Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_1** | Confirm that Kentucky Power will place rates into effect at the end of the suspension period, subject to the conditions of KRS 278.190. |

**RESPONSE**

Confirmed.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_2** | Refer to Application, Section III, Volume 1, Direct Testimony of Linda Schlessman, Exhibit LMS-8. Provide a table showing the amount of accelerated tax depreciation Kentucky Power recorded during each of the periods shown in Exhibit LMS-8 and explanation(s) for why net operating loss carryforwards in those periods should be attributed to accelerated tax depreciation based on those amounts. |

**RESPONSE**

As discussed on pages 22-23 of Company Witness Schlessman's Direct Testimony, the Company used the "with and without" methodology per IRS guidance to determine whether the net operating loss carryforwards should be attributed to accelerated tax depreciation. Application of that methodology demonstrated that 100% of the net operating loss carryforwards are attributed to accelerated tax depreciation. Please see KPCO_R_KPSC_PHDR_2_Attachment1 for the requested analysis.

Witness: Linda M. Schlessman

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_3** | Refer to Application, Section III, Volume 1, Direct Testimony of Jaclyn Cost, Exhibit JNC-1. Provide the Cost of Service Study (COSS) in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible. |

**RESPONSE**

See attachment KPCO_R_KPSC_PHDR_3_Attachment1, KPCO_R_KPSC_PHDR_3_Attachment2, KPCO_R_KPSC_PHDR_3_Attachment3 and KPCO_R_KPSC_PHDR_3_Attachment4 for the full Class Cost of Service study and supporting Allocation Workpapers. To the extent there are value-pasted inputs on the Allocators tab, the supporting information may be obtained from the Workpapers. There are no protected columns, though some may be hidden for presentation purposes but can be expanded.

Witness: Jaclyn N. Cost

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_4** | Provide any written cost reduction plan for American Electric Power Company, Inc. (AEP) and Kentucky Power, individually or collectively. If no cost reduction plan has been created, explain why not. |

**RESPONSE**

Kentucky Power and AEP engage in constant and ongoing efforts to reduce costs, where possible, for the benefit of customers. In the Company's response to KPSC 1-1(b), a list of cost-reducing efforts and process efficiencies was provided in KPCO_R_KPSC_1_1_Attachment2. These efforts primarily yield process efficiencies which indirectly produce savings by increasing the productivity of the Company's existing workforce. No written document detailing the implementation of those cost reduction efforts and processes exist; nonetheless, such efforts and processes have and continue to produce efficiencies and overall customer benefit.

Additionally, AEP engages in numerous other initiatives aimed at cost savings for the benefit of all customers. Please see KPCO_R_KPSC_PHDR_4_Attachment1 for a listing of some initiatives and KPCO_R_KPSC_PHDR_4_Attachment2 for documentation on one such initiative.

Witness: Brian K. West

# FutureGen

## Generation's Continuous Improvement Journey

***December 2023***

# FutureGen Overview

**FutureGen is the next evolution of Generation's continuous improvement initiative striving for top decile performance and self-funding critical work**

**Structured Process**

| Determine Target | Training & Bootcamps | Monitor, Check & Adjust | Sustainment |
|---|---|---|---|
| Detailed gap analysis to best in class & value drivers resulting in low to high target by facility/org | Partnership between Gen Leadership, Front Line, EPI, & McKinsey<br><br>Boot camps produced ideas w/business cases & plans to achieve target | Bi-Weekly Transformation Office update to ask for help, share fleet wide ideas, ensure progress | Sustainment plan for each facility and continued idea generation |

**Kentucky Plans**

| 2022 | 2023 | 2024 |
|---|---|---|
| Mitchell Due Diligence Completed 2021 & Boot camp in 2022 | Mitchell in sustainment<br>Big Sandy due diligence completed | Big Sandy Boot Camp scheduled July-September<br><br>Mitchell continued idea generation and top decile comparison |

**AEP Goal: I**mproving performance for (a) Availability, (b) Cost, and (C) Fuel Efficiency.

# WAVE Definitions

Net recurring benefits (LE, $k): Sum of the annualized latest estimate (LE) recurring impacts (Categorized as the difference between reoccurring benefits and reoccurring costs).

Implementation costs (LE, $k): Sum of the annualized latest estimate (LE) implementation costs of each impact. (Categorized as One Time Costs)

One-time benefits (LE, $k): Sum of the annualized latest estimate (LE) one-time benefits of each impact. (Categorized as One Time Benefits)

Stage – See slide 3  for details.  Only stage =>4 are included in data.

Impact Estimate Values – See chart to right

## Impact Estimate Value Logic

Below is the logic that Wave typically uses to calculate the impact estimate value.
***Note:*** *some configurations of Wave do not include estimates or the logic to calculate estimates may vary slightly.*

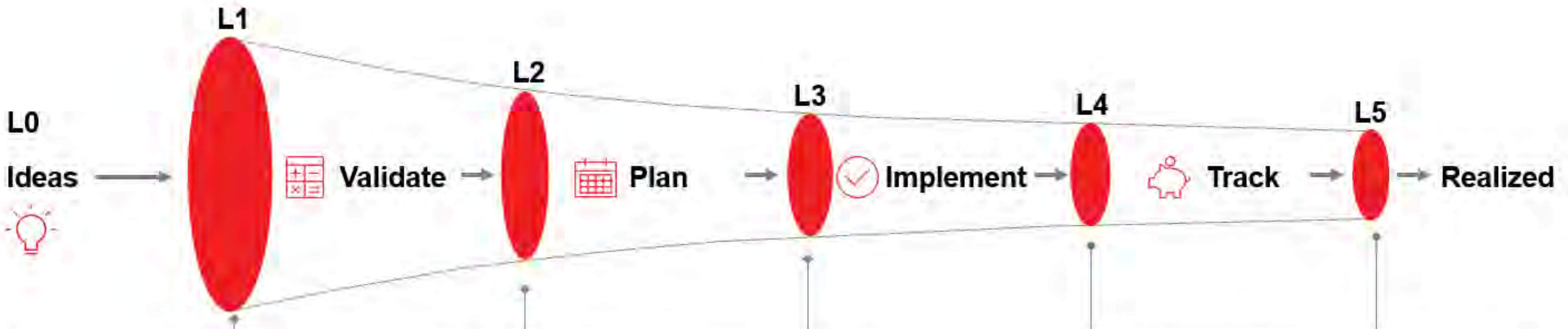
- If the Initiative is in L0, L1, or L2, the estimate values will be equal to the Plan values starting from the current month. Past months will have no value
- If the Initiative is in L3 or L4:
  - The estimate values will equal to the actual values for the first month up to the current month
  - The estimate values will equal to the forecast values starting from the current month (if there is no actual value yet) or the next month
- If the Initiative is in L5:
  - The estimate values will equal to the actual values for the first month up to the current month
  - The estimate values will equal to the forecast values starting from the month the Initiative reached L5 (using actual values where available)
- If the Initiative's Weekly status is Cancelled or On hold, the estimate line will not be calculated

**Impact Estimate Example**

The following example shows how the impact estimate varies based on available values.

| | May | June | July | August | September |
|---|---|---|---|---|---|
| Planned | 10 | 10 | 15 | 15 | |
| Actual | 9 | 8 | | | |
| Forecast | | 12 | 17 | | |
| **Estimate** | 9 | 8 | 17 | 15 | - |

# INITIATIVE PROGRESSION: Stage gates create a sharp, fact-based view on status of initiatives




**Key requirements for approval**

| L1 | L2 | L3 | L4 | L5 |
|---|---|---|---|---|
| • **Idea generated with** a high-level estimate of impact<br>• Initiative Owner identified | • **Estimate of impact** (with supporting documentation)<br>• Idea **analyzed** for feasibility, impact and risks<br>• **Determine L3 and L4** dates | • Detailed **Implementation Plan** developed (L4 date locked in)<br>• **KPIs to track delivery** of impact | • Milestones including the **Money Step** is **complete**<br>– *The Money Step is the Milestone in the execution plan which when executed is required for the impact to be realized* | • **Impact accruing at expected ramp rate** (recurring)<br>• **Full impact accrued** (one-time) |

# Impact Summaries in WAVE as of 12/13/2023 for measures listed & stages =>4

**All tabs** filtered by **Plant/Corporate Groups** (Initiative) [Mitchell], **OpCo** (Initiative) [<all>]

Multiple measures, grouped by Plant/Corporate Groups (Initiative), filtered by Stage (Initiative)

| | Net recurring benefits (LE, $k) | Implementation costs (planned, $k) | One-time benefits (planned, $k) |
|---|---|---|---|
| Mitchell | $k 22,135.7 | $k 14,200.6 | $k 1,596.1 |
| **Total** | **$k 22,135.7** | **$k 14,200.6** | **$k 1,596.1** |

* KY/APCO jointly own Mitchell, information above is Mitchell overall..

# Net Reoccurring Benefits in WAVE as of 12/13/2023 for measures listed & stages =>4


| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Earnings Offset | $k 5.0 | | | | | | | | **$k 5.0** |
| O&M | | $k 6,171.4 | | | | | | | **$k 6,171.4** |
| Capital | | | $k 2,266.6 | | | | | | **$k 2,266.6** |
| Fuel | | | | $k 9,081.0 | | | | | **$k 9,081.0** |
| Purchased Power | | | | | $k 4,122.3 | | | | **$k 4,122.3** |
| Reagents | | | | | | $k 489.4 | | | **$k 489.4** |
| Removal | | | | | | | | | |
| Revenue | | | | | | | | | |
| **Total** | **$k 5.0** | **$k 6,171.4** | **$k 2,266.6** | **$k 9,081.0** | **$k 4,122.3** | **$k 489.4** | | | **$k 22,135.7** |

* KY/APCO jointly own Mitchell, information above is Mitchell overall..

# One Time Costs in WAVE as of 12/13/2023 for measures listed & stages =>4

All tabs filtered by Plant/Corporate Groups (Initiative) [Mitchell], OpCo (Initiative) [<all>]

Implementation costs (LE, $k), grouped by What is the type of impact? > Metric Category (Impact), colored by What is the type of impact? > Metric Category (Impact), filtered by Stage (Initiative)


| | | | | |
|---|---|---|---|---|
| Earnings Offset | | | | |
| O&M | $k 3,588.7 | | | **$k 3,588.7** |
| Capital | | $k 8,493.9 | | **$k 8,493.9** |
| Fuel | | | | |
| Purchased Power | | | | |
| Reagents | | | | |
| Removal | | | $k 2,118.0 | **$k 2,118.0** |
| Revenue | | | | |
| **Total** | **$k 3,588.7** | **$k 8,493.9** | **$k 2,118.0** | **$k 14,200.6** |

* KY/APCO jointly own Mitchell, information above is Mitchell overall..

# One Time Benefits in WAVE as of 12/13/2023 for measures listed & stages =>4


| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Earnings Offset | | | | | | | | | |
| O&M | | $k 1,024.0 | | | | | | | **$k 1,024.0** |
| Capital | | | $k 565.6 | | | | | | **$k 565.6** |
| Fuel | | | | $k 6.5 | | | | | **$k 6.5** |
| Purchased Power | | | | | | | | | |
| Reagents | | | | | | | | | |
| Removal | | | | | | | | | |
| Revenue | | | | | | | | | |
| **Total** | | **$k 1,024.0** | **$k 565.6** | **$k 6.5** | | | | | **$k 1,596.1** |

* KY/APCO jointly own Mitchell, information above is Mitchell overall..

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_5** | Refer to Kentucky Power's Response to Commission Staff's Sixth Request for Information (Staff's Sixth Request), Item 10 and Item 11. For customers served under Tariff Residential Service, for the years 2022, 2021, and 2020, for each month individually, provide a comparative graph with dot plot of the distribution of monthly usage with LIHEAP customers' bills in one color using kWh by month and all other customers in another color using kWh by month. |

**RESPONSE**

The Company only maintains, from a data retention standpoint, three years of LIHEAP data. Please see KPCO_R_KPSC_PHDR_5_Attachment1 for the monthly kWh frequency distributions for residential and residential LIHEAP customers.

Witness: Michael M. Spaeth

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_6** | Refer to Kentucky Power's Company's Motion to Approve the Settlement Agreement, Direct Testimony of Brian West, Exhibit BKW 1-S, Exhibit 5. Provide the proposed tariff sheets filed with the Application with a redline version showing the changes made in the Settlement Agreement. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_6_Attachment1 for the requested information.

Witness: Lerah M. Kahn

P.S.C. KY. NO. 13
CANCELLING P.S.C. KY. NO. 12

# Kentucky Power Company

1645 Winchester Avenue
Ashland, KY 41101
www.kentuckypower.com

Rates, Terms, and Conditions for Furnishing
Electric Service

*Applicable to the Entire Territory Served by Kentucky Power Company In: Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan Counties.*

## Filed with the Kentucky Public Service Commission

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Index



DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service

**1. Application**

Applications may be made in writing, on-line, or via telephone for customers who wish to have the Company provide electric service. Requests for service are to be made in the Customer's legal name by telephone or online at: www.kentuckypower.com. The Company has the right to reject any request for service based on 807 KAR 5:006 Section 15 and associated tariffs.

The Company may require verification of ownership of property, lease, applicant's identity, or other requested information.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. A copy of the tariff is also available online at www.kentuckypower.com.

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

**2. Inspection**

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may disconnect or refuse to connect service if the customer's wiring is deemed unsafe by the Company.

Company may also require a new state electrical inspection should tampering, illegal use or theft of service be the basis for disconnection service.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

**3. Service Connections**

Service connections will be provided in accordance with 807 KAR-5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

*Continued on Sheet 2-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

**Service Connections Continued**

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

**4. Deposits**

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty acceptable to the Company to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained by the Company during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which may be considered by the Company cumulatively:

i. Satisfactory payment history with the Company, which may be established by paying all bills by due date, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no energy diversion or theft of service;
ii. Satisfactory payment history with another utility acceptable to the Company;
iii. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit; or
iv. Providing evidence of other collateral acceptable to Company.

C. Method of Determination – Calculated Deposits

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.
b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

*Continued on Sheet 2-3*

# Terms and Conditions of Service Continued

D. Additional or Supplemental Deposit Requirement
An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or payment history. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplement deposit will be charged to the account the next time the account is billed.

i. Satisfactory payment history is defined as paying all bills by due date, having no disconnections for nonpayment, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.
ii. A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to present a risk of nonpayment, including but not limited to: below a “BB+” level at Standard and Poor’s or below “Ba1” at Moody’s. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer presents a risk of nonpayment, a deposit may be required.

E. Recalculation of Customer Deposit
When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer’s actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment. No refund will be made if the Customer’s bill is delinquent at the time of the recalculation.

**5. Payments**
Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer’s service.

A. Equal Payment Plan (Budget)
Nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above and all residential customers have the option of paying a fixed amount each month under the Company’s Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customer’s estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence April through December.

In the last month of the plan (the “settle-up month”) if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

Customers currently enrolled in the Equal Payment Plan whose settle-up month falls within the period December through February may elect to change their settle-up month to November or March if their Equal Payment Plan account is current.

If a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the Equal Payment Plan and restored to regular billing.

*Continued on Sheet 2-4*

# Terms and Conditions of Service Continued

B. Average Monthly Payment Plan
The Average Monthly Payment Plan (AMP Plan) is available to all residential customers and nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above.

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

If a customer who is currently enrolled in the AMP Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the AMP Plan and restored to regular billing.

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve (12) consecutive billing months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments
All bills are due and payable within twenty-one (21) days after their mailing date. Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

*Delayed Payment Charge*
The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. On all non-residential accounts not so paid, an additional charge of 5% of the unpaid balance will be applied. Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding six months.

*Continued on Sheet 2-5*

# Terms and Conditions of Service Continued

**6. Payment Arrangements**

In accordance with 807 KAR 5:006 Section 14(2), Kentucky Power shall negotiate and accept reasonable payment arrangements at the request of a residential customer who has received a termination notice for failure to pay. Payment arrangements will include the following reasonable provisions:

a. Partial Payment Plans are available up to the day prior to the termination date printed on a customer's termination notice.
b. Partial Payment Plans are available only for current balances and balances up to 30 days in arrears.
c. Any balance more than 30 days in arrears must be paid in full at least one business day prior to the date the Partial Payment Plan is established.
d. Customers with delinquent or otherwise unsatisfied Partial Payment Plans may not be eligible for a Partial Payment Plan.
e. Unpaid deposit amounts are not eligible for inclusion in a Partial Payment Plan.
f. Company reserves the right to refuse unverifiable third-party pledges toward a customer's obligations under a Partial Payment Plan.
g. Customer shall be advised, in writing or by telephone, the date and the amount of payment(s) due. Service may be terminated without additional notice if the Customer fails to meet the obligations of the agreed plan.
h. It is the responsibility of the customer presenting the Medical Certificate to contact the Company to negotiate a payment arrangement based upon the customer's ability to pay. The payment arrangement shall require that the account become current no later than October 15.
i. Customers presenting Certification from the Cabinet for Health and Family Services must do so during the initial 10 day termination notice period. As a condition of the 30-day extension, the customer shall exhibit good faith by entering into a payment arrangement.

**7. Underground Service**

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

Please see Tariff Sheet No. 14-1 for the underground differential cost schedule.

**8. Company's Liability**

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or cause to be avoided. Force Majeure events includes acts of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

*Continued on Sheet 2-6*

# Terms and Conditions of Service Continued

**Company's Liability Continued**

Any new installation, upgrade or other modification of an existing meter installation shall be made using only Company-supplied or Company-approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

**9. Customer's Liability**

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking the seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make internal or external adjustments to any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause. The Company may assess charges based on electric usage and damages to all Company equipment.

**10. Extension of Service**

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

*Continued on Sheet 2-7*

# Terms and Conditions of Service Continued

**Extension of Service Continued**

For services to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to service the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain
or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer's requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

i. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer's requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.
ii. The annual energy cost based on the latest available production costs related to the Customer's estimated annual energy use requirements.
iii. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as describe herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in venue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer' electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

**11. Extension of Service to Mobile Home**
The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

**12. Location and Maintenance of Company Equipment**
The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

*Continued on Sheet 2-8*

# Terms and Conditions of Service Continued

**13. Billing Form**

Pursuant to 807 KAR 5:006, Section 7, copies of the billing forms used by the Company are shown on Sheet Nos. 2-14 thru 2-23.

**14. Rate Schedule Selection**

The Company will explain to the Customer, at the beginning of service or upon request, the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedules.

**15. Monitoring Usage**

At least once quarterly the Company will monitor the usage of each customer according to the following procedure:

a. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
b. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
c. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
d. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
e. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
f. The Company will notify the Customer of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

In addition to the quarterly monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

**16. Use of Energy by Customer**

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

*Continued on Sheet 2-9*

# Terms and Conditions of Service Continued

**Use of Energy by Customer Continued**

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs that specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

**17. <u>Residential Service</u>**

Except as otherwise provided in these tariffs, individual residences shall be served individually with single-phase secondary service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or primary service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff, and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

**18. <u>Denial or Discontinuance of Service</u>**

The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent or person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made.

*Continued on Sheet 2-10*

# Terms and Conditions of Service Continued

**Denial or Discontinuance of Service Continued**

Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect.

Residential disconnections are limited to the hours of 8:00 a.m. through 5:00 p.m. Monday through Thursday and 8:00 a.m. through noon on Friday.

Residential service will not be disconnected for 24 hours following when temperatures are forecast to be 32 degrees or below or 95 degrees or higher.

**19. Special Charges**

a. Reconnection and Disconnect Charges
In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

| | |
|---|---|
| Reconnect for nonpayment during regular hours | $4.70 |
| Reconnect at the end of the day (no "Call Out" required) | $30.00 |
| Reconnect for nonpayment when a "Call Out" is required prior to 8:00 p.m. ~~PM~~ (A "Call Out" is when an employee must be called in to work on overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made when a "Call Out" after 8:00 p.m. is required) | $95.00 |
| Reconnect for nonpayment when double time is required (Sunday and Holiday) | $124.00 |
| Termination or field trip | $4.70 |

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

b. Meter Read Check
Pursuant to 807 KAR 5:006, Section 9(3)(d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $21.00 to cover the handling cost.

c. Returned Check Charge
In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $14.65 to cover the handling costs.

d. Meter Test Charge
Where test of a meter is made upon written request by the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged $48.00 if such test shows that the meter was not more than two percent (2%) fast.

*Continued on Sheet 2-11*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

**Special Charges Continued**

e. Work Performed on Company's Facilities at Customer's Request
Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

**20. Refunds to Residential Customers**
The Company may make a refund to residential customers by one of the following means: a credit to the Customer's bill, a prepaid card, or a check or electronic funds transfer (EFT).

The Company acting through its customer service representative shall fully address and resolve any customer complaints or disputes related to: (a) the accuracy of the names and last known addresses of the customer to receive prepaid cards; (b) the effective delivery and receipt of the prepaid cards; and (c) the amount of any refunds.

**21. Alerts and Subscriptions**
Kentucky Power offers an optional Mobile Alert Service for customers through which participating customers can elect to receive notifications from the Company via e-mail or text message. The Company provides billing and payment alerts and alerts relating to outages. These alerts are supplemental to standard communications from the Company and to the extent any discrepancies exist between the information contained in the mobile alerts and the information contained in standard communications from the Company, the information in the standard communications from the Company shall prevail.

Customers interested in receiving mobile alerts from Kentucky Power may sign up for the service through the Company's website at www.kentuckypower.com. The full terms and conditions of participating in the Kentucky Power Mobile Alert Service are included on the Company's website. Customers wishing to participate in Kentucky Power's Mobile Alert Service and to receive alerts via e-mail should add communications@kentuckypower-mail.com to the customer's email address book or spam filter to avoid alert communications from Kentucky Power being directed to spam. Customers are advised to contact their e-mail service provider for instructions on how to add addresses to an address book or spam filter if needed.

E-mail addresses from which alerts are sent through the Mobile Alert Service are used for sending e-mails only. Any e-mails sent to those addresses will not be received by the Company and the Company will not respond. Any electronic communication to the Company should be sent to Communications@kentuckypower-mail.com.

There is no charge from the Company for the Mobile Alert Service; however, message and data rates may apply. Customers are advised to verify message and data rates with their cellular and internet service providers.

Information regarding the types of alerts and the Mobile Alert Service in general are provided below.

*Continued on Sheet 2-12*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

**Alerts and Subscriptions Continued**

Billing and Payment Alerts
Billing and payment alerts provided through Kentucky Power's Mobile Alert Service are in addition to regular billing statements, payment notifications, disconnect notices, or other standard communications sent by Kentucky Power or its third party partners as required by law, regulation, or tariff filed by Kentucky Power or its subsidiaries. These alerts are not a replacement for any regular billing statement, payment notifications, disconnect notices, or other standard communications. In the event of a discrepancy between the information provided in a billing or payment alert provided through the Mobile Alert Service and the information provided in the Company's standard communication, the information in the standard communication shall prevail.

Kentucky Power shall not have any liability for any delay or failure to deliver a billing or payment alert or for any mistakes or errors in any billing or payment alert provided through the Mobile Alerts Service.

Outage Alerts
Kentucky Power provides alerts relating to system outages through its Mobile Alert Service. Outage alerts will be sent when the Company has evidence of an outage at a subscribed address. Due to variations in equipment from one area to another, it is possible that the accuracy of outage alerts will vary from one area to another. Recipients shall consider any outage related information as guidance and not as an absolute guarantee. Kentucky Power will send outage related notifications based upon available information and does not guarantee that the notifications will be without error.

Planned outages and short-duration outages will normally not generate an outage-related notification. During large-scale outage events, the frequency and timeliness of outage updates may be impacted.

Kentucky Power shall not have any liability for any delay or failure to deliver an outage-related notification.

General
Kentucky Power does not warrant or guarantee that alerts will be sent or received, and Kentucky Power shall not be responsible for any lost or misdirected messages.

Customers electing to participate in Kentucky Power's Mobile Alert Service authorize the Company to contact them via their elected communication method with transactional messages pertaining to the service. Participation in the Mobile Alert Service shall be considered as affirmative consent to receive the related messages should these messages ever be classified as commercial in nature.

Kentucky Power shall not have any liability under any theory of recovery, whether in contract or tort, for any loss or damages due to delay or failure to deliver an alert through the Mobile Alert Service. Without limiting the previous sentence, Kentucky Power disclaims any liability, expressed or implied, for indirect or consequential damages arising from a customer's subscription to Kentucky Power's Mobile Alert Service.

Customer agrees not to publish, copy, communicate to the public, edit, retransmit, or amend any data received as part of Kentucky Power's Mobile Alert Service. The data communicated via the Mobile Alert Service is provided for the participating customer's personal non-commercial use only and may not be used for any other purpose.

Personal information and data ("Personal Data") provided by customers when using Kentucky Power's Mobile Alert Service will only be used by Kentucky Power and its suppliers and contractors for Mobile Alert Service-related purposes. Data other than Personal Data may be aggregated and used by the Company for the purpose of undertaking market research or in facilitating reviews, developments and improvements to Kentucky Power's Mobile Alert Service.

*Continued on Sheet 2-13*

# Terms and Conditions of Service Continued

**Alerts and Subscriptions Continued**

Customers participating in the Mobile Alert Service may discontinue a portion of or all alerts at any time by modifying their alert subscription or by unsubscribing entirely. Customers wishing to modify or unsubscribe from the Mobile Alert Service may do so at the Company's website: www.kentuckypower.com or by contacting Kentucky Power's Customer Operations Centers at 1-800-572-1113. Kentucky Power will process a request to unsubscribe from the Mobile Alert Service within ten days of receiving the request. Kentucky Power is authorized to send a communication to a customer requesting to unsubscribe from the Mobile Alert Service to confirm the request.

The terms and conditions the Company's Mobile Alert Service shall be governed by applicable state law.

Customers electing to participate in the Company's Mobile Alert Service agree to the terms and conditions of the service and further agree that the terms and conditions may be updated from time to time. The Company will provide customers participating in the Mobile Alert Service with updated terms and conditions as they become effective. Customers participating in the Mobile Alert Service must take affirmative action to withdraw from the service if the customer does not agree with any new or updated term or condition of service. Failure to withdraw after an updated term and condition is provided by the Company means that the customer accepts the new or updated terms and conditions.

<u>Additional Terms and Conditions for E-mail Alerts</u>
If a customer sends an email to Kentucky Power with questions or comments, Kentucky Power may use the customer's e-mail address and other personal information included in the correspondence in order to respond. If a customer provides the Company with an e-mail address in order to receive alerts, Kentucky Power may use that e-mail address to send the customer other types of information.

A customer may unsubscribe from receiving e-mail alerts by clicking the "Unsubscribe" link near the bottom of an e-mail alert.

<u>Additional Terms and Conditions for Text Message Alerts</u>
Customers may elect to receive text alerts through Kentucky Power's Mobile Alert Service. For text alerts, message and data rates may apply consistent with the customer's mobile phone service agreement. Kentucky Power assumes no responsibility for any service charges received from customer's mobile phone service providers for text alerts received through the Mobile Alert Service. Kentucky Power is not responsible for and will not be liable for any breach of the terms of an agreement between a customer electing to receive text alerts through the Mobile Alert System and that customer's mobile phone service provider or for any mistake that may arise in the billing process.

To receive text alerts from the Company through the Mobile Alert Service, the customer must be the owner or legitimate user of the mobile phone registered or have the express consent of the owner or legitimate user. Customers electing to receive text alerts from the Company through the Mobile Alert Service are responsible for providing and maintaining a mobile phone and ensuring connection to a mobile network capable of receiving the text alerts.

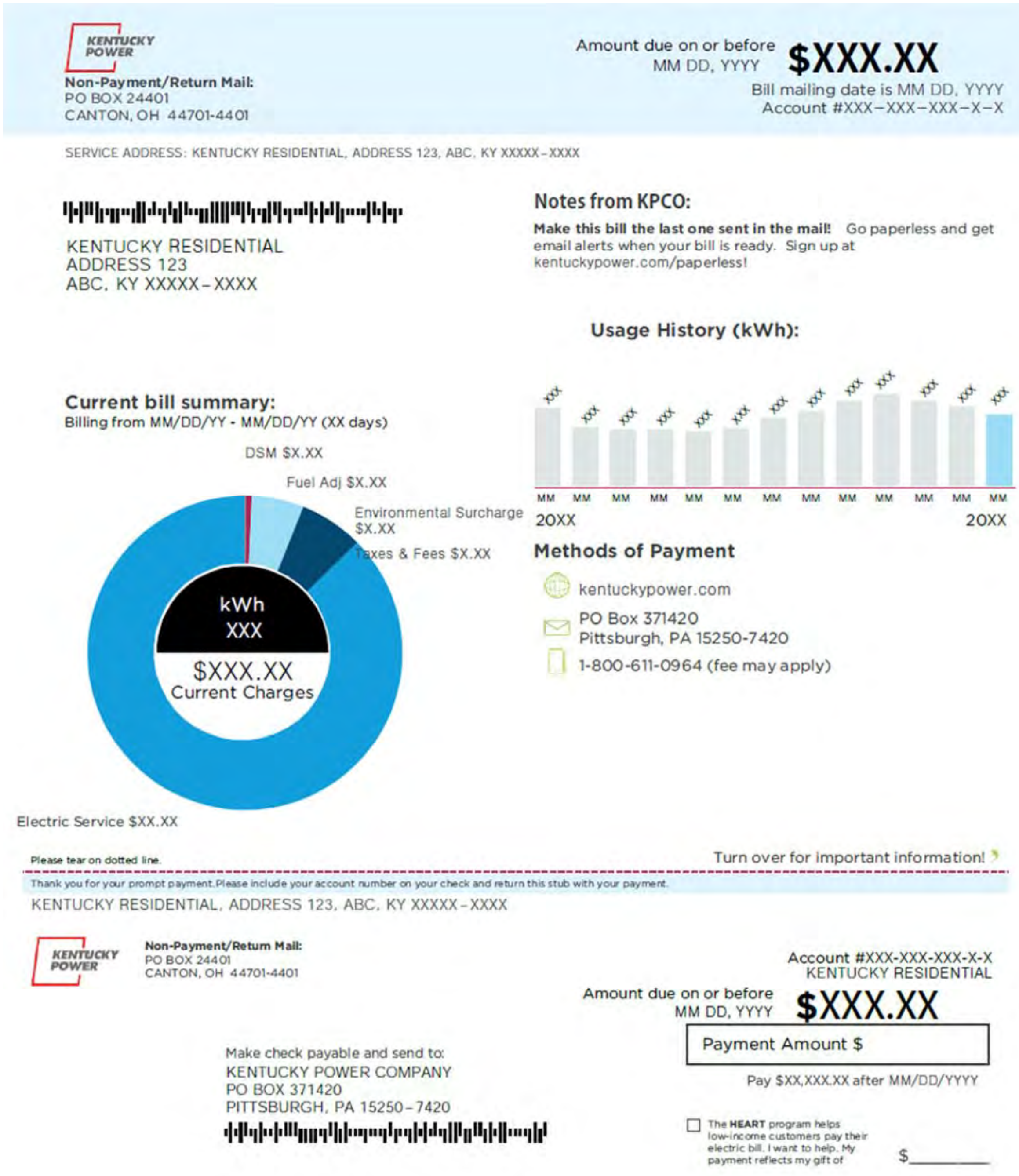
Customers electing to receive text alerts through the Mobile Alert Service acknowledge that the text alerts may, at any time, be adversely affected by problems with the mobile phone network including, without limitation, interference to the network coverage. Kentucky Power shall not be responsible or liable for any loss, damage, or expense incurred directly or indirectly by customers electing to receive text alerts through the Mobile Alert Service as a result of any difficulties experienced by any cellular phone service provider.

In the event a customer electing to receive text alerts through the Mobile Alert Service changes mobile phone service providers or telephone number, that customer is required to subscribe again to receive text alerts. If no alerts are sent or received for eighteen months, a customer's opt-in to that offering will expire. A customer must opt-in again to the program in order to receive alerts.

Kentucky Power may discontinue text alerts at any time. Customers electing to receive text alerts through the Mobile Alert Service will receive text alerts from 23711. Customers may unsubscribe from text alerts by texting STOP to 23711 and may obtain assistance via text by texting HELP to 23711.

*Continued on Sheet 2-14*

## Terms and Conditions of Service Continued



KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX–XXX–XXX–X–X

SERVICE ADDRESS: KENTUCKY RESIDENTIAL, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX

**Notes from KPCO:**

**Make this bill the last one sent in the mail!** Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

**Usage History (kWh):**

XXX XXX XXX XXX XXX XXX XXX XXX XXX XXX XXX XXX XXX
MM MM MM MM MM MM MM MM MM MM MM MM MM
20XX 20XX

**Current bill summary:**
Billing from MM/DD/YY - MM/DD/YY (XX days)

DSM $X.XX
Fuel Adj $X.XX
Environmental Surcharge $X.XX
Taxes & Fees $X.XX
kWh XXX
$XXX.XX Current Charges
Electric Service $XX.XX

**Methods of Payment**

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY RESIDENTIAL, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY POWER

**Non-Payment/Return Mail:**
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY RESIDENTIAL

Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420
PITTSBURGH, PA 15250–7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

*Continued on Sheet 2-15*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

**Service Address:**

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX

**Account #XXX-XXX-XXX-X-X**

**Line Item Charges:**

| | | |
|---|---|---|
| **Previous Charges** | | |
| Total Amount Due At Last Billing | $ | XXX.XX |
| Payment 02/07/22 - Thank You | | -XXX.XX |
| **Previous Balance Due** | **$** | **X.XX** |
| **Current KPCO Charges** | | |
| **Tariff XXX - Residential Service XX/XX/XX** | | |
| Rate Billing | $ | XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XX.XX |
| Residential Energy Assistance @ $X.XX | | XX.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Renewable Power Option Rider | | XX.XX |
| KY Power Solar Credit @ $X.XX | | XX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | XX.XX |
| School Tax | | XX.XX |
| City's Franchise Fee | | XX.XX |
| State Sales Tax | | XX.XX |
| **Current Balance Due** | **$** | **XXX.XX** |
| Homeserve Warranty Service | $ | XX.XX |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX kWh |
| Service Period XX/XX – XX/XX | | | | | Multiplier 1 |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

**Notes from KPCO:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

**Usage Details:**

Values reflect changes between current month and previous month.


Total usage for the past 12 months: X,XXX kWh
Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

**Service Address:**

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX-XXXX

**Account #XXX-XXX-XXX-X-X**

**Line Item Charges:**

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XXX.XX |
| Payment 02/07/22 - Thank You | | -XXX.XX |
| **Previous Balance Due** | **$** | **X.XX** |
| **Current KPCO Charges** | | |
| **Tariff XXX - Residential Service XX/XX/XX** | | |
| Rate Billing | $ | XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XX.XX |
| Residential Energy Assistance @ $X.XX | | XX.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Renewable Power Option Rider | | XX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | XX.XX |
| School Tax | | XX.XX |
| City's Franchise Fee | | XX.XX |
| State Sales Tax | | XX.XX |
| **Current Balance Due** | **$** | **XXX.XX** |
| Homeserve Warranty Service | $ | XX.XX |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX kWh |
| Service Period XX/XX – XX/XX | | | | | Multiplier 1 |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

**Notes from KPCO:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

**Usage Details:**

Values reflect changes between current month and previous month.


Total usage for the past 12 months: X,XXX kWh
Average (Avg.) monthly usage: XXX kWh

*Continued on Sheet 2-16*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

**Non-Payment/Return Mail:**
PO BOX 24401
CANTON, OH 44701-4401

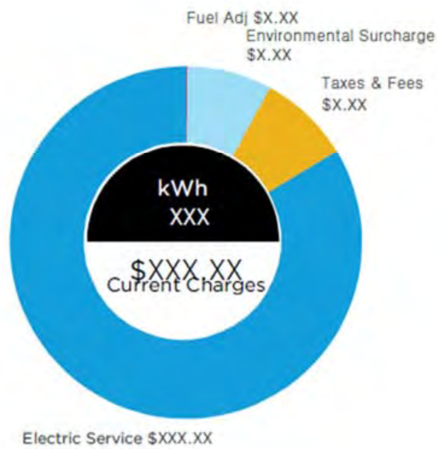
Amount due on or before MM DD, YYYY **$XXX.XX**
Bill mailing date is MM DD, YYYY

SERVICE ADDRESS: KENTUCKY GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX-XXXX

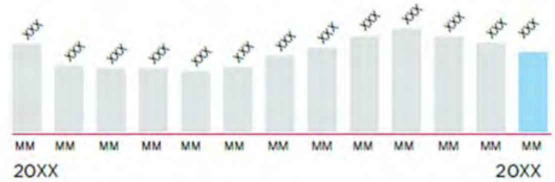
KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX-XXXX

**Notes from KPCO:**

**Make this bill the last one sent in the mail!** Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!




**Usage History (kWh):**




**Methods of Payment**

kentuckypower.com

PO Box 371420
Pittsburgh, PA 15250-7420

1-800-611-0964 (fee may apply)

**Need to get in touch?**

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line. Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

**Non-Payment/Return Mail:**
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY GENERAL SERVICE

Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

*Continued on Sheet 2-17*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

**Service Address:**

KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX

**Account #XXX-XXX-XXX-X-X**

## Line Item Charges:

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX.XX |
| Payment XX/XX/XX - Thank You | | -XX.XX |
| **Previous Balance Due** | **$** | **X.XX** |
| **Current KPCO Charges** | | |

| **Tariff XXX - General Service XX/XX/XX** | | |
|---|---|---|
| Rate Billing | $ | XX.XX |
| Demand Charge | | XX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | XX.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Renewable Power Option Rider | | XX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | XX.XX |
| School Tax | | XX.XX |
| City's Franchise Fee | | XX.XX |
| State Sales Tax | | XX.XX |
| **Current Balance Due** | **$** | **XX.XX** |

## Meter Read Details:

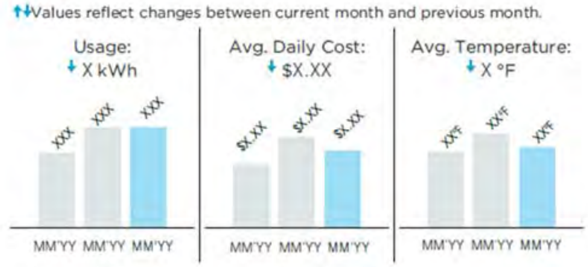
| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| XXX | Actual | XXX | Actual | XXX | XXX kWh |
| Service Period XX/XX - XX/XX | | | | | Multiplier 1 |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

## Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

## Usage Details:

↑↓Values reflect changes between current month and previous month.




Total usage for the past 12 months: XXX kWh
Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX.XX |
| Payment XX/XX/XX - Thank You | | -XX.XX |
| **Previous Balance Due** | **$** | **X.XX** |
| **Current KPCO Charges** | | |
| **Tariff XXX - General Service XX/XX/XX** | | |
| Rate Billing | $ | XX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XX.XX |
| ~~Kentucky Economic Development Surcharge @ $X.XX~~ | | ~~XX.XX~~ |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Renewable Power Option Rider | | XX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | XX.XX |
| School Tax | | XX.XX |
| City's Franchise Fee | | XX.XX |
| State Sales Tax | | XX.XX |
| **Current Balance Due** | **$** | **XX.XX** |

## Meter Read Details:

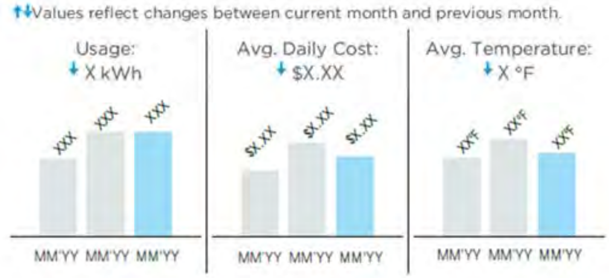
| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| XXX | Actual | XXX | Actual | XXX | XXX kWh |
| Service Period XX/XX - XX/XX | | | | | Multiplier 1 |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

## Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

## Usage Details:

↑↓Values reflect changes between current month and previous month.




Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

*Continued on Sheet 2-18*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

## Terms and Conditions of Service Continued

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX-XXX-XXX-X-X

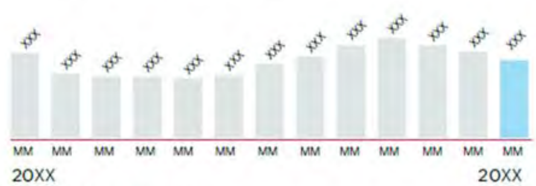
SERVICE ADDRESS: KENTUCKY LARGE GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY LARGE GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX-XXXX

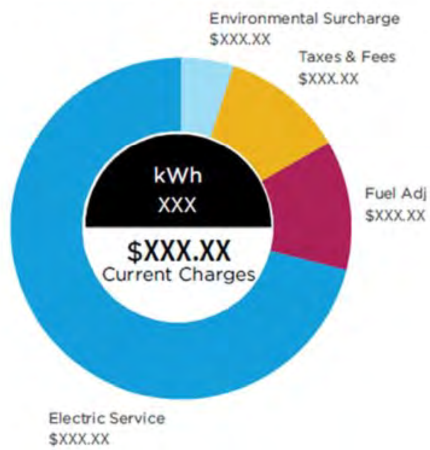
**Notes from KPCO:**

**Make this bill the last one sent in the mail!** Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

**Usage History (kWh):**




**Current bill summary:**
Billing from MM/DD/YY - MM/DD/YY (XX days)




**Methods of Payment**

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

**Need to get in touch?**

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY LARGE GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY LARGE GENERAL SERVICE
Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

*Continued on Sheet 2-19*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

## Terms and Conditions of Service Continued

KENTUCKY POWER

**Service Address:**

KENTUCKY LARGE GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX-XXXX
**Account #XXX-XXX-XXX-X-X**

| Billed Usage MM/YY | | | | |
|---|---|---|---|---|
| Usage | Power Factor | Power Factor Constant | Meter Location Comp. | Billed Usage |
| XXX | - | - | - | XXXX kWh |
| XXX | - | - | - | XXX kW |
| XXX | - | - | - | XXX.XXX KVA |

**Line Item Charges:**

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XXX.XX |
| Payment XX/XX/XX - Thank You | | -XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| Current Charges | | |
| **Tariff XXX - Large General Service XX/XX/XX** | | |
| Rate Billing | $ | XXX.XX |
| Demand Charge | | -XXX.XX |
| Economic Development Rider - IBDD | | -XXX.XX |
| Economic Development Rider - SBDD | | -XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XXX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XXX.XX |
| Renewable Power Option Rider | | XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XXX.XX |
| Envrionmental Adj. X.XXXXX% | | XXX.XX |
| School Tax | | XXX.XX |
| City's Franchise Fee | | XXX.XX |
| State Sales Tax | | XXX.XX |
| **Current Balance Due** | **$** | **XXX.XX** |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X,XXX | Actual | X | X kVAR |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kW |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| | | | | | |
| Service Period MM/DD - MM/DD | | | | | Multiplier XXX |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

**Notes from Kentucky Power:**

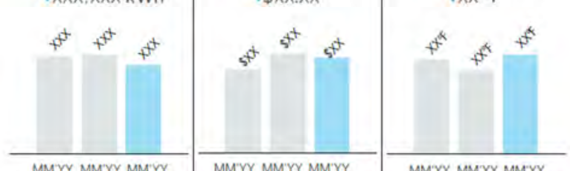
Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

↑↓Values reflect changes between current month and previous month.

Usage: ↓XXX,XXX kWh | Avg. Daily Cost: ↓$XX.XX | Avg. Temperature: ↑XX °F




Total usage for the past 12 months: XXX kWh
Average (Avg.) monthly usage: XXX kWh

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XXX.XX |
| Payment XX/XX/XX - Thank You | | -XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| Current Charges | | |
| **Tariff XXX - Large General Service XX/XX/XX** | | |
| Rate Billing | $ | XXX.XX |
| Economic Development Rider - IBDD | | -XXX.XX |
| Economic Development Rider - SBDD | | -XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | XXX.XX |
| DSM Adj @ X.XXXXX Per kWh | | XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XXX.XX |
| Renewable Power Option Rider | | XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XXX.XX |
| Envrionmental Adj. X.XXXXX% | | XXX.XX |
| School Tax | | XXX.XX |
| City's Franchise Fee | | XXX.XX |
| State Sales Tax | | XXX.XX |
| **Current Balance Due** | **$** | **XXX.XX** |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X.XXX | Actual | X | X kVAR |
| X | X | X.XXX | Actual | X.XXX | XXX.XX kW |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| | | | | | |
| Service Period MM/DD - MM/DD | | | | | Multiplier XXX |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

| Net Usage : XXX,XXX kWh | Billable Usage: XXX,XXX kWh |
|---|---|

**Notes from Kentucky Power:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

↑↓Values reflect changes between current month and previous month.


Total usage for the past 12 months: XXX kWh
Average (Avg.) monthly usage: XXX kWh

*Continued on Sheet 2-20*

## Terms and Conditions of Service Continued

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XX,XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX-XXX-XXX-X-X

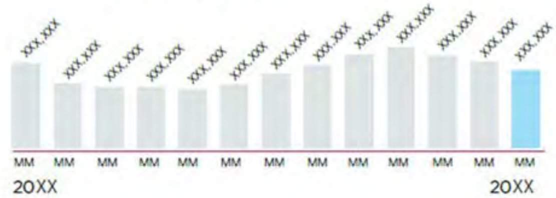
SERVICE ADDRESS: KENTUCKY INDUSTRIAL-PRIMARY & SECONDARY, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY INDUSTRIAL– PRIMARY & SECONDARY
ADDRESS 123
ABC, KY XXXXX-XXXX

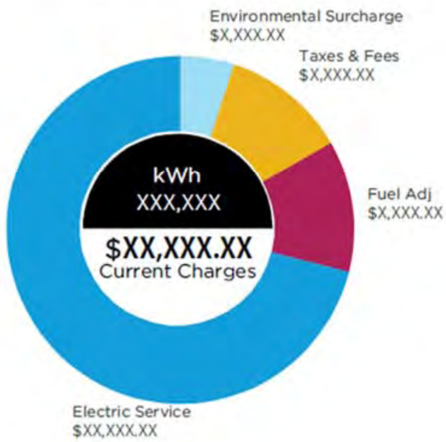
**Notes from KPCO:**

**Make this bill the last one sent in the mail!** Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

**Usage History (kWh):**




**Current bill summary:**
Billing from MM/DD/YY - MM/DD/YY (XX days)




**Methods of Payment**

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

**Need to get in touch?**
Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY INDUSTRIAL-PRIMARY & SECONDARY, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY INDUSTRIAL – PRIMARY & SECONDARY
Amount due on or before MM DD, YYYY **$XX,XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

*Continued on Sheet 2-21*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

**Service Address:**

KENTUCKY INDUSTRIAL—PRIMARY & SECONDARY

ADDRESS 123
ABC, KY XXXXX–XXXX

**Account #XXX-XXX-XXX-X-X**

| Billed Usage MM/YY | | | | |
|---|---|---|---|---|
| Usage | Power Factor | Power Factor Constant | Meter Location Comp. | Billed Usage |
| XXX,XXX | - | - | - | XXX,XXX kWh |
| XXX,XXX | - | - | - | XXX,XXX kW On-Pk |
| XXX,XXX | - | - | - | XXX,XXX kW Off-Pk |
| Contract Capacity = X,XXX.X | | | | High Prev Demand = X,XXX.X On-Pk<br>High Prev Demand = X,XXX.X Off-Pk |

**Line Item Charges:**

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX,XXX.XX |
| Payment XX/XX/XX - Thank You | | -XX,XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| **Current Charges** | | |
| **Tariff XXX - Industrial General Service XX/XX/XX** | | |
| Rate Billing | $ | XXXXX.XX |
| Demand Charge | | -X,XXX.XX |
| Economic Development Rider - IBDD | | -X,XXX.XX |
| Economic Development Rider - SBDD | | -X,XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -X,XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | X,XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Purchased Power Adj. $X.XXXXX/kW | | X,XXX.XX |
| Renewable Power Option Rider | | X,XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | X,XXX.XX |
| School Tax | | X,XXX.XX |
| City's Franchise Fee | | X,XXX.XX |
| State Sales Tax | | X,XXX.XX |
| **Total Balance Due** | **$** | **XX,XXX.XX** |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X,XXX | Actual | X | X kVAR |
| X | X | X,XXX | Actual | X,XXX | XXX,XX kW On-Pk |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| X | X | X,XXX | Actual | X,XX | XXX.X kW Off-Pk |
| X | X | X,XXX | Actual | X,XXX | XXX,XX kVAR |
| Service Period MM/DD - MM/DD | | | Multiplier XXX | | |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

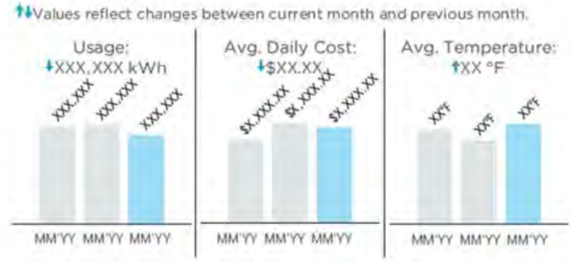
**Notes from Kentucky Power:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

Values reflect changes between current month and previous month.




Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

**Service Address:**

KENTUCKY INDUSTRIAL—PRIMARY & SECONDARY
ADDRESS 123
ABC, KY XXXXX-XXXX
**Account #XXX-XXX-XXX-X-X**

| Billed Usage MM/YY | | | | |
|---|---|---|---|---|
| Usage | Power Factor | Power Factor Constant | Meter Location Comp. | Billed Usage |
| XXX,XXX | - | - | - | XXX,XXX kWh |
| XXX,XXX | - | - | - | XXX.XXX kW On-Pk |
| XXX,XXX | - | - | - | XXX.XXX kW Off-Pk |
| Contract Capacity = X,XXX.X | | | High Prev Demand = X,XXX.X On-Pk | |
| | | | High Prev Demand = X,XXX.X Off-Pk | |

**Line Item Charges:**

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX,XXX.XX |
| Payment XX/XX/XX - Thank You | | -XX,XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| Current Charges | | |
| **Tariff XXX - Industrial General Service XX/XX/XX** | | |
| Rate Billing | $ | XX,XXX.XX |
| Economic Development Rider - IBDD | | -X,XXX.XX |
| Economic Development Rider - SBDD | | -X,XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -X,XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | X,XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Distribution Reliability Rider @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Purchased Power Adj. $X.XXXXX/kW | | X,XXX.XX |
| Renewable Power Option Rider | | X,XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | X,XXX.XX |
| School Tax | | X,XXX.XX |
| City's Franchise Fee | | X,XXX.XX |
| State Sales Tax | | X,XXX.XX |
| **Total Balance Due** | **$** | **XX,XXX.XX** |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X,XXX | Actual | X | X kVAR |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kW On-Pk |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| X | X | X.XXX | Actual | X.XX | XXX.X kW Off-Pk |
| X | X | X.XXX | Actual | X.XXX | XXX.XX kVAR |
| Service Period MM/DD - MM/DD | | | | | Multiplier XXX |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

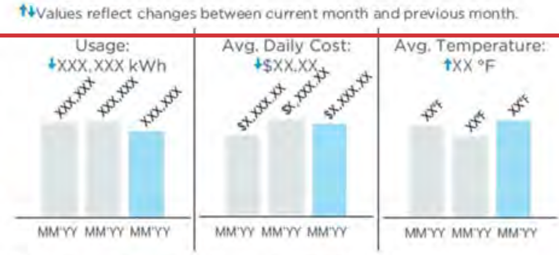
**Notes from Kentucky Power:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

Values reflect changes between current month and previous month.




Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

*Continued on Sheet 2-22*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XX,XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX-XXX-XXX-X-X

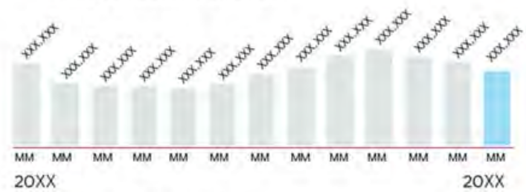
SERVICE ADDRESS: KENTUCKY INDUSTRIAL–SUBTRANSMISSION & TRANSMISSION, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION & TRANSMISSION
ADDRESS 123
ABC, KY XXXXX-XXXX

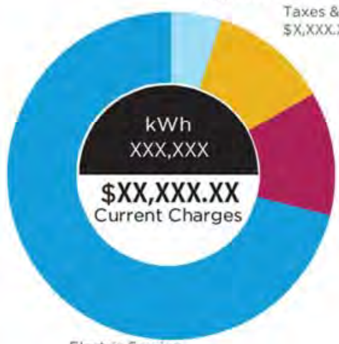
**Notes from KPCO:**

**Make this bill the last one sent in the mail!** Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

**Usage History (kWh):**




**Current bill summary:**
Billing from MM/DD/YY - MM/DD/YY (XX days)




**Methods of Payment**

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

**Need to get in touch?**

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY INDUSTRIAL–SUBTRANSMISSION & TRANSMISSION, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY INDUSTRIAL – SUBTRANSMISSION & TRANSMISSION
Amount due on or before MM DD, YYYY **$XX,XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $______

*Continued on Sheet 2-23*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Terms and Conditions of Service Continued

KENTUCKY POWER

**Service Address:**

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

**Account #XXX-XXX-XXX-X-X**

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX,XXX.XX |
| Payment XX/XX/XX - Thank You | | -XX,XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| Current Charges | | |

| | | |
|---|---|---|
| **Tariff XXX - Industrial General Service XX/XX/XX** | | |
| Rate Billing | $ | XX,XXX.XX |
| Demand Charge | | -X,XXX.XX |
| Economic Development Rider - IBDD | | -X,XXX.XX |
| Economic Development Rider - SBDD | | -X,XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -X,XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | X,XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Purchased Power Adj. $X.XXXXX/kW | | X,XXX.XX |
| Renewable Power Option Rider | | X,XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | X,XXX.XX |
| School Tax | | X,XXX.XX |
| City's Franchise Fee | | X,XXX.XX |
| State Sales Tax | | X,XXX.XX |
| **Total Balance Due** | **$** | **XX,XXX.XX** |

| Billed Usage MM/YY | | | | |
|---|---|---|---|---|
| Usage | Power Factor | Power Factor Constant | Meter Location Comp. | Billed Usage |
| XXX,XXX | - | - | - | XXX,XXX kWh |
| XXX,XXX | - | - | - | XXX.XXX kW On-Pk |
| XXX,XXX | - | - | - | XXX.XXX kW Off-Pk |
| Contract Capacity = X,XXX.X | | High Prev Demand = X,XXX.X On-Pk | | |
| | | High Prev Demand = X,XXX.X Off-Pk | | |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X,XXX | Actual | X | X kVAR |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kW On-Pk |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| X | X | X,XXX | Actual | X.XX | XXX.X kW Off-Pk |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kVAR |
| Service Period MM/DD - MM/DD | | | Multiplier XXX | | |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

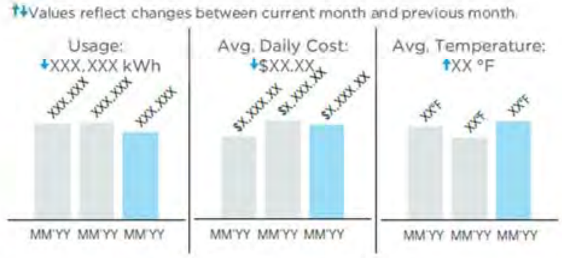
**Notes from Kentucky Power:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

Values reflect changes between current month and previous month.




Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

KENTUCKY POWER

**Service Address:**

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

**Account #XXX-XXX-XXX-X-X**

| Billed Usage MM/YY | | | | |
|---|---|---|---|---|
| Usage | Power Factor | Power Factor Constant | Meter Location Comp. | Billed Usage |
| XXX.XXX | - | - | - | XXX.XXX kWh |
| XXX.XXX | - | - | - | XXX.XXX kW On-Pk |
| XXX.XXX | - | - | - | XXX.XXX kW Off-Pk |
| Contract Capacity = X,XXX.X | | | | High Prev Demand = X,XXX.X On-Pk<br>High Prev Demand = X,XXX.X Off-Pk |

| Previous Charges | | |
|---|---|---|
| Total Amount Due At Last Billing | $ | XX,XXX.XX |
| Payment XX/XX/XX - Thank You | | -XX,XXX.XX |
| **Previous Balance Due** | **$** | **XX.XX** |
| **Current Charges** | | |
| **Tariff XXX - Industrial General Service XX/XX/XX** | | |
| Rate Billing | $ | XX,XXX.XX |
| Economic Development Rider - IBDD | | -X,XXX.XX |
| Economic Development Rider - SBDD | | -X,XXX.XX |
| Federal Tax Change @ X.XXXXX- Per kWh | | -X,XXX.XX |
| Fuel Adj @ X.XXXXX Per kWh | | X,XXX.XX |
| Kentucky Economic Development Surcharge @ $X.XX | | X.XX |
| Purchased Power Adj. $X.XXXXX/kWh | | XX.XX |
| Purchased Power Adj. $X.XXXXX/kW | | X,XXX.XX |
| Renewable Power Option Rider | | X,XXX.XX |
| Securitization Financing Rider X.XXXXX% | | XX.XX |
| Decommissioning Rider X.XXXXX% | | XX.XX |
| Envrionmental Adj. X.XXXXX% | | X,XXX.XX |
| School Tax | | X,XXX.XX |
| City's Franchise Fee | | X,XXX.XX |
| State Sales Tax | | X,XXX.XX |
| **Total Balance Due** | **$** | **XX,XXX.XX** |

**Meter Read Details:**

| Meter #XXXXXXXXX | | | | | |
|---|---|---|---|---|---|
| Previous | Type | Current | Type | Metered | Usage |
| X | X | X,XXX | Actual | X | X kVAR |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kW On-Pk |
| XXXXX | Actual | XXXXX | Actual | XXX | XXX,XXX kWh |
| X | X | X,XXX | Actual | X.XX | XXX.X kW Off-Pk |
| X | X | X,XXX | Actual | X,XXX | XXX.XX kVAR |
| Service Period MM/DD - MM/DD | | | | | Multiplier XXX |
| Next scheduled read date should be between MM DD and MM DD. | | | | | |

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

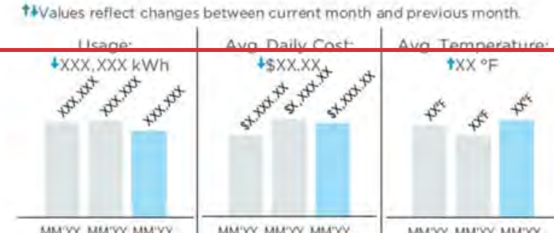
**Notes from Kentucky Power:**

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

**Usage Details:**

↑↓Values reflect changes between current month and previous month.




Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Capacity and Energy Control Program

**Introduction**
Kentucky Power Company's Capacity and Energy Control Program outlines the procedures the Company will follow in the event of an emergency that threatens the continued reliable operation of bulk power supply system. Notwithstanding any provisions of this Capacity and Energy Control Program, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law. The Company's Capacity and Energy Control Program consists of three sets of procedures:

I. Procedures During Abnormal System Frequency
II. Capacity Deficiency Program
III. Energy Emergency Control Program

Specific details regarding the Company's Capacity and Energy Control Program are included in the Company's Emergency Operating Plan ("EOP"). A copy of the Company's current EOP is on file with the Kentucky Public Service Commission in Administrative Case No. 345. Where this tariff diverts from the Company's EOP, the EOP Plan shall govern.

**I. AEP/PJM Procedures During Abnormal System Frequency (EOP Section IV)**

a. Purpose
Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP/PJM program described below provides procedures for reducing the consumption of electric energy on the Company's system in the event of a period of abnormal system frequency.

b. AEP/PJM Procedures
From 59.8 – 60.2 Hz, to the extent practicable, the Company will utilize all operating and emergency reserves. The manner of utilization of these reserves depends on the behavior of the System during the emergency.

For rapid frequency decline, the Company will utilize capacity that is on-line and automatically responsive to frequency (spinning reserve) and such measures as interconnection assistance and automatic load reductions to arrest the decline in frequency.

If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, will invoke non-automatic procedures involving operating and emergency reserves. These efforts will continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities. At 59.75 Hz, the Company will suspend Automatic Generation Control (AGC) and notify Interruptible Customers to drop load.

If at any time the decline in area frequency is arrested below 59.5 Hz, the Company will evaluate whether the area should manually shed an additional 5% of its initial load. If, after five minutes, shedding 5% of load has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5% of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the EOP subsection titled, "Isolation of Coal-fired Generating Units."

Automatic Load Shedding Program details are located in Section IV of the Company's EOP.

*Continued on Sheet 3-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Capacity and Energy Control Program Continued

**II. Capacity Deficiency Program (EOP Section III)**

a. Purpose
The purpose of the Capacity Deficiency Program is to provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP) East/PJM Eastern System in the event of a capacity deficiency. A capacity deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

b. AEP East/PJM Procedures
There are three general levels of emergency actions for capacity deficiencies:

- Alerts - issued in advance of the operating day for elevated awareness and to give time for advanced preparations.
- Warnings - issued real time, typically preceding, and with an estimated time/window for a potential future action.
- Actions - issued real time and requires PJM and/or Member response. PJM actions are consistent with NERC and RFC EOP standards.

The Company may also issue an Advisory, one or more days in advance of the operating day during which a capacity deficiency may occur, that are general in nature and are for elevated awareness only. No preparations or actions are required in response to an Advisory.

**Alerts**

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

**Real Time Emergency Procedures (Warnings and Actions)**

Warnings
Warnings are issued in real time during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. Generally, a warning precedes an associated action. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO.

Actions
The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

The Company's EOP includes a nine-step warning and action procedure during capacity deficiency conditions.

*Continued on Sheet 3-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Capacity and Energy Control Program Continued

c. Priority Levels

For the purpose of these capacity deficiency procedures, the following Priority Levels for loads have been established:

I. Essential Health and Safety Uses – to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use:

a. Hospitals, which shall be limited to institutions providing medical care to patients.

b. Life Support Equipment, which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

c. Police Stations and Government Detention Institutions, which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

d. Fire Stations, which shall be limited to facilities housing mobile fire-fighting apparatus.

e. Communication Services, which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

f. Water and Sewage Services, which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

g. Transportation and Defense-related Services, which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential services such as street, highway and signal-lighting.

Although, when practical, these types of uses will be given special consideration when implementing the manual load- shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses – Except as described in Section C.III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use – Residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

*Continued on Sheet 3-4*

# Capacity and Energy Control Program Continued

**Priority Levels Continued**

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses – The following and similar types of uses of electric energy shall be considered nonessential for all customers:

a. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

b. General interior lighting levels greater than minimum functional levels.

c. Show-window and display lighting.

d. Parking lot lighting above minimum functional levels.

e. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

f. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

g. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

d. Curtailment Procedures
In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on interruptible contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Contract Service – Interruptible Power Tariff or the Alternate Feed Service Rider.

2. Power output will be maximized at Company's generating units.

3. Company use of energy at its generating stations will be reduced to a minimum.

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

*Continued on Sheet 3-5*

# Capacity and Energy Control Program Continued

e. Service Restoration Procedures
Where practical, priority uses will be considered in restoring service and service will be restored in the order I through V as defined under Priority Levels described above. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times on its website to aid customers in assessing the need for alternative power sources and temporary relocations.

**III. Energy Emergency Control Program (EOP Section V)**

a. Introduction
The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

b. Procedures
In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction. For further information, see EOP Section V.

With regard to mandatory curtailments, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

# Standard Nominal Voltages

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

**Secondary Distribution Voltages**

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire, Single-phase 480 volts two wire, and Single-phase 240/480 volts three wire.

**Primary Distribution Voltages**

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y; 19,900 and 34,500Y.

**Subtransmission Line Voltages**

The Company's sub transmission voltage levels are 34,500; 46,000; and 69,000.

**Transmission Line Voltages**

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

# Tariff R.S.
# (Residential Service)

**Availability of Service**
Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

**Rate** *(Tariff Codes 015, 017, 022)*

| | | |
|---|---|---|
| Service Charge | $20.00 | per month |
| Energy Charge | 12.036~~12.947~~¢ | per kWh |

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Residential Energy Assistance | Sheet No. 26 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Volunteer Departments** *(Tariff Code 024)*
Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually.

**Kentucky Power Solar Credit**
The Kentucky Power Solar Credit is available only to residential customers participating in LIHEAP (Low Income Home Energy Assistance Program). This credit is funded solely by Kentucky Power's Solar Gardens distributed solar program. Total program funding per year is equal to 50% of the energy benefits produced by the Kentucky Power's Solar Gardens distributed solar program in the twelve months ending in October of each year. Total program funding will be split ratably between all eligible customers and credited to eligible customers' bills. The credit will be automatically reflected on eligible customers' electric bills in equal amounts over the course of January through March of each year. The credit amount will be updated annually and trued-up annually to match the number of customers actually participating in the program at the time of the true-up. The monthly Fuel Adjustment Clause also will be adjusted to account for removal of 50% of the energy benefits produced by the Solar Gardens facilities and credited to eligible customers as detailed in this section.

| | | |
|---|---|---|
| Credit Amount | $X.XX | per month (January – March) |

*Continued on Sheet 5-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S. Continued
# (Residential Service)

**Optional Seasonal Provision** (*Tariff Code XXX*)
For residential customers desiring to take seasonal rate service. Service under this provision shall be for a minimum of 12 consecutive billing months.

| | | |
|---|---|---|
| Service Charge | $20.00 | per month |
| Energy Charge | | |
| All kWh used during winter billing months (December-March) | 11.150~~11.947~~¢ | per kWh |
| All kWh used during all other months (April-November) | 12.756~~13.762~~¢ | per kWh |

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clause section.

**Storage Water Heating Provision**
This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

| *Tariff Code* | | | |
|---|---|---|---|
| *012* | For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at | 8.546¢ ~~8.603¢~~ | per kWh |
| *013* | For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at | 8.546¢ ~~8.603¢~~ | per kWh |
| *014* | For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at | 8.546¢ ~~8.603¢~~ | per kWh |

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

**Load Management Water-Heating Provision** *(Tariff Code 011)*
For residential customers who install a load management water-heating system which consumes electrical energy during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at 8.546~~8.603~~¢ per kWh.

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

*Continued on Sheet 5-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S. Continued
# (Residential Service)

**Load Management Water Heating Provision Continued**

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated; it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

**Special Terms and Conditions**

This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S.Tariff. Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

*Continued on Sheet 5-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S.-L.M.-T.O.D.
# (Residential Service Load Management Time of Day)

**Availability of Service**
Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

**Rate** *(Tariff Codes 028, 030, 032, 034)*

| | | |
|---|---|---|
| Service Charge | $23.00 | per month |
| Energy Charge<br>All kWh used during on-peak billing period | 16.613¢<br>~~18.646¢~~ | per kWh |
| All kWh used during off-peak billing period | 8.546¢<br>~~8.603¢~~ | per kWh |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

**Conservation and Load Management Credit**
For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per kWh for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Residential Energy Assistance | Sheet No. 26 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

*Continued on Sheet 5-5*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S.-L.M.-T.O.D. Continued
# (Residential Service Load Management Time of Day)

**Separate Metering Provision**
Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $4.30 per month.

**Separate Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated; it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

*Continued on Sheet 5-6*

# Tariff R.S.-T.O.D.
# (Residential Service Time of Day)

**Availability of Service**
Available for residential electric service through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

**Rate** *(Tariff Code 036)*

| | | |
|---|---|---|
| Service Charge | $23.00 | per month |
| Energy Charge<br>All kWh used during on-peak billing period | 16.613¢ ~~18.646¢~~ | per kWh |
| All kWh used during off-peak billing period | 8.546¢ ~~8.603¢~~ | per kWh |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Residential Energy Assistance | Sheet No. 26 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

*Continued on Sheet 5-7*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S.-T.O.D.2
# (Experimental Residential Service Time of Day 2)

**Availability of Service**
Available on a voluntary, experimental basis to individual residential customers for residential electric service through a multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

**Rate** *(Tariff Code 027)*

| | | |
|---|---|---|
| Service Charge | $23.00 | per month |
| Energy Charge<br>All kWh used during Summer on-peak billing period | 17.561¢ ~~18.921¢~~ | per kWh |
| All kWh used during Winter on-peak billing period | 12.678¢ ~~13.642¢~~ | per kWh |
| All kWh used during off-peak billing period | 11.415¢ ~~12.277¢~~ | per kWh |

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

| **Months**<br>Approximate Percent (%) of Annual Hours | **On-Peak**<br>16% | **Off-Peak**<br>84% |
|---|---|---|
| Winter Period:<br>November 1 to March 31 | 7:00 AM to 11:00 AM<br>6:00 PM to 10:00 PM | 11:00 AM to 6:00 PM<br>10:00 PM to 7:00 AM |
| Summer Period:<br>May 15 to September 15 | Noon to 6:00 PM | 6:00 PM to Noon |
| All Other Calendar Periods | None | Midnight to Midnight |

Note: All kWh consumed during Saturday and Sunday are billed at the off-peak level.

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Residential Energy Assistance | Sheet No. 26 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

*Continued on Sheet 5-8*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff R.S.-T.O.D.2 Continued
# (Experimental Residential Service Time of Day 2)

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

*Continued on Sheet 5-9*

# Tariff R.S.D.
# (Residential Demand-Metered Electric Service)

**Availability of Service**
Available for residential electric service through one single-phase multiple-register demand meter. Availability is limited to the first 1,000 customers applying for service under this tariff.

**Monthly Rate** *(Tariff Code 018)*

| | | |
|---|---|---|
| Service Charge | $23.00 | per customer |
| Energy Charge | | |
| All kWh used during on-peak billing period | 9.090~~11.843~~¢ | per kWh |
| All kWh used during off-peak billing period | 8.546~~8.603~~¢ | per kWh |
| Demand Charge | $5.94~~6.77~~ | for each kW of monthly billing demand |

For the purpose of this tariff, the on-peak billing period is defined as follows:
Months of October – May: 7:00 AM to 11:00 AM for all weekdays
Months of June – September 4:00 PM to 9:00 PM for all weekdays
The off-peak billing period is defined as all weekday hours not defined above as on-peak and all hours of Saturday and Sunday

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Residential Energy Assistance | Sheet No. 26 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Monthly Billing Demand**
Customer's demand will be taken monthly to be the highest registration of a 60 minute integrating demand meter or indicator during the on- peak period.

**Special Terms and Conditions**
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff G.S.
# (General Service)

**Availability of Service**
Available for general service customers. Customers may continue to qualify for service under this tariff until their average maximum demand exceeds 100 kW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

**Rate**

| Tariff Code | Service Voltage | Demand Charge ($/kW) | First 4,450 kWh (¢/kWh) | Over 4,450 kWh (¢/kWh) | Monthly Service Charge ($) |
|---|---|---|---|---|---|
| 211, 212, 215, 216, 218 | Secondary | 8.36~~8.82~~ | 12.292 | 10.813 | 28.00 |
| 217, 220 | Primary | 7.56~~8.03~~ | 10.790 | 9.533 | 120.00 |
| 236 | Subtransmission | 5.84~~6.38~~ | 9.763 | 8.629 | 460.00 |

The Demand Charge shall apply to all monthly billing demand in excess of 10 kW.

**Minimum Charge**
This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by the monthly billing demand in excess of 10 kW.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Metered Voltage**
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

*Continued on Sheet 6-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff G.S. Continued
# (General Service)

**Monthly Billing Demand**
Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The monthly billing demand shall be the greater of: (1) Customer's metered kW demand, (2) 60% of the Customer's contract capacity in excess of 100 kW, or (3) 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

The Company reserves the right to install a demand meter on any customer receiving service under this tariff. A demand meter will be installed by the Company for customers with monthly kWh usage of 4,450 kWh or greater.

**Recreational Lighting Service Provision**
Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

**Rate** *(Tariff Code 214)*

| | | |
|---|---|---|
| Service Charge | $28.00 | per month |
| Energy Charge | 13.247~~13.336~~¢ | per kWh |

**Load Management Time of Day Provision**
Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

**Rate** *(Tariff Codes 223 and 225)*

| | | |
|---|---|---|
| Service Charge | $28.00 | per month |
| Energy Charge | | |
| All kWh used during on-peak billing period | 18.443¢ ~~18.567¢~~ | per kWh |
| All kWh used during off-peak billing period | 8.501¢ ~~8.558¢~~ | per kWh |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

*Continued on Sheet 6-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff G.S. Continued
# (General Service)

**Optional Unmetered Service Provision**
Available to customers who qualify for Tariff G.S., have a demand of less than 10 KW, and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

**Rate** *(Tariff Codes 204 (Metered) and 213 (Unmetered))*

| | | |
|---|---|---|
| Customer Charge | $15.00 | per month |
| | | |
| Energy Charge | | |
| First 4,450 kWh per month | 12.292¢ | per kWh |
| All Over 4,450 kWh per month | 10.813¢ | per kWh |

**Term of Contract**
Contracts under this tariff may be required of customers. Contracts under this tariff will be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

*Continued on Sheet 6-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff S.G.S.-T.O.D.
# (Small General Service Time of Day Service)

**Availability of Service**
Available on a voluntary, basis for general service to customers being served at secondary distribution voltage with one single-phase, multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Customers not meeting the requirements for availability under this tariff will be permitted to continue service under this tariff only for continuous service at the premises occupied on or prior to June 30, 2015.

**Rate** *(Tariff Code 227)*

| | | |
|---|---|---|
| Service Charge | $28.00 | per month |
| Energy Charge | | |
| All kWh used during Summer on-peak billing period | 19.417~~19.545~~¢ | per kWh |
| All kWh used during Winter on-peak billing period | 13.693~~13.784~~¢ | per kWh |
| All kWh used during off-peak billing period | 12.266~~12.349~~¢ | per kWh |

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

| **Months**<br>Approximate Percent (%)<br>of Annual Hours | **On-Peak**<br>16% | **Off-Peak**<br>84% |
|---|---|---|
| Winter Period:<br>November 1 to March 31 | 7:00 AM to 11:00 AM<br>6:00 PM to 10:00 PM | 11:00 AM to 6:00 PM<br>10:00 PM to 7:00 AM |
| Summer Period:<br>May 15 to September 15 | Noon to 6:00 PM | 6:00 PM to Noon |
| All Other Calendar Periods | None | Midnight to Midnight |

Note: All kWh consumed during weekends are billed at the off-peak level.

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

*Continued on Sheet 6-5*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff S.G.S.-T.O.D. Continued
# (Small General Service Time of Day)

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

*Continued on Sheet 6-6*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff M.G.S.-T.O.D.
# (Medium General Service Time of Day)

**Availability of Service**
Available for general service to customers with average maximum demands greater than 10 KW but not more than 100 KW being served by a multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

**Rate** *(Tariff Code 229)*

| | | |
|---|---|---|
| Service Charge | $28.00 | per month |
| Energy Charge | | |
| All kWh used during on-peak billing period | 18.443¢ ~~18.567¢~~ | per kWh |
| All kWh used during off-peak billing period | 8.501¢ ~~8.558¢~~ | per kWh |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the Service Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Metered Voltage**
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

*Continued on Sheet 6-7*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff M.G.S.-T.O.D. Continued
# (Medium General Service Time of Day)

**Special Terms and Conditions**

This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

# Tariff L.G.S.
# (Large General Service)

**Availability of Service**
Available for general service to customers with average maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

**Rate**

| | Service Voltage | | | |
|---|---|---|---|---|
| | **Secondary** | **Primary** | **Subtransmission** | **Transmission** |
| *Tariff Code* | 240, 242, 260 | 244, 246, 264 | 248, 268 | 250, 270 |
| Service Charge per Month | $97.00 | $145.00 | $750.00 | $750.00 |
| Demand Charge per kW | $13.84~~10.39~~ | $12.23~~8.95~~ | $8.46~~5.39~~ | $8.28~~5.25~~ |
| Excess Reactive Charge per KVA | $3.46 | $3.46 | $3.46 | $3.46 |
| Energy Charge per kWh | 8.198~~8.796~~¢ | 7.352~~7.867~~¢ | 5.524~~5.975~~¢ | 5.430~~5.874~~¢ |

**Minimum Charge**
Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Metered Voltage**
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

*Continued on Sheet 7-2*

# Tariff L.G.S. Continued
# (Large General Service)

**Monthly Billing Demand**
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

**Determination of Excess Kilovolt-Ampere (KVA) Demand**
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

**Load Management Time of Day Provision**
Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

**Rate** *(Tariff Code 251)*

| | | |
|---|---|---|
| Service Charge | $97.00 | per month |
| Energy Charge | | |
| All kWh used during on-peak billing period | 15.932¢ ~~14.934¢~~ | per kWh |
| All kWh used during off-peak billing period | 8.639¢ ~~8.695¢~~ | per kWh |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

**Term of Contract**
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

**Contract Capacity**
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

*Continued on Sheet 7-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff L.G.S. Continued
# (Large General Service)

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

*Continued on Sheet 7-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff L.G.S.-T.O.D.
# (Large General Service Time of Day)

**Availability of Service**
Available for general service customers with average maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

**Rate**

| | Service Voltage | | | |
|---|---|---|---|---|
| | **Secondary** | **Primary** | **Subtransmission** | **Transmission** |
| *Tariff Code* | 256 | 257 | 258 | 259 |
| Service Charge per Month | $97.00 | $145.00 | $750.00 | $750.00 |
| Demand Charge per kW | $9.33~~9.13~~ | $7.91~~7.76~~ | $4.39~~4.40~~ | $4.32~~4.33~~ |
| Excess Reactive Charge per KVA | $3.46 | $3.46 | $3.46 | $3.46 |
| On-Peak Energy Charge per kWh | 12.648~~11.793~~¢ | 12.052~~11.238~~¢ | 11.878~~11.075~~¢ | 11.731~~10.938~~¢ |
| Off-Peak Energy Charge per kWh | 6.138~~6.194~~¢ | 5.966~~6.021~~¢ | 5.916~~5.970~~¢ | 5.874~~5.927~~¢ |

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

**Minimum Charge**
Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Metered Voltage**
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

*Continued on Sheet 7-5*

# Tariff L.G.S.-T.O.D. Continued
# (Large General Service Time of Day)

**Monthly Billing Demand**
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

**Determination of Excess Kilovolt-Ampere (KVA) Demand**
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

**Term of Contract**
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

**Contract Capacity**
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff I.G.S.
# (Industrial General Service)

**Availability of Service**
Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet average maximum requirements.

**Rate**

| | Service Voltage | | | |
|---|---|---|---|---|
| | **Secondary** | **Primary** | **Subtransmission** | **Transmission** |
| *Tariff Code* | 356 | 358/370 | 359/371 | 360/372 |
| Service Charge per Month | $276.00 | $276.00 | $794.00 | $1,353.00 |
| Demand Charge per kW<br>Of monthly on-peak billing demand<br>Of monthly off-peak billing demand | <br>$26.99~~27.32~~<br>$1.84 | <br>$24.94~~25.31~~<br>$1.78 | <br>$17.36~~17.89~~<br>$1.75 | <br>$17.00~~17.52~~<br>$1.73 |
| Energy Charge per kWh | 3.156~~3.214~~¢ | 3.007~~3.063~~¢ | 2.964~~3.018~~¢ | 2.927~~2.981~~¢ |

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand………………………………….. $0.69/KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

**Minimum Demand Charge**
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

| Secondary | Primary | Subtransmission | Transmission |
|---|---|---|---|
| $25.68~~26.01~~ / kW | $23.68~~24.05~~ / kW | $16.12~~16.64~~ / kW | $15.77~~16.29~~ / kW |

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

**Minimum Charge**
This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

*Continued on Sheet 8-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff I.G.S. Continued
# (Industrial General Service)

**Metered Voltage**
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

**Monthly Billing Demand**
The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

**Term of Contract**
Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

**Contract Capacity**
The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiples of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

# Tariff M.W.
# (Municipal Waterworks)

**Availability of Service**
Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

**Rate** *(Tariff Code 540)*

| | | |
|---|---|---|
| Service Charge | $25~~28~~.00 | per month |
| Energy Charge<br>All kWh used per month | 11.073¢<br>~~10.506¢~~ | per kWh |

**Minimum Charge**
This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $9.55 per KVA as determined from customer's total connected load.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Term of Contract**
Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff O.L.
# (Outdoor Lighting)

**Availability of Service**

Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium, Mercury Vapor and Metal Halide lamps shall cease on January 14, 2021.

**Base Fuel Rate**

Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

**Rate**

A. Overhead Lighting Service

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **High Pressure Sodium** | 094 | 100 (9,500 Lumens) | $10.25~~10.53~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 113 | 150 (16,000 Lumens) | $11.69~~12.01~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 097 | 200 (22,000 Lumens) | $14.17~~14.55~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 103 | 250 (28,000 Lumens) | $20.19~~20.74~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 098 | 400 (50,000 Lumens) | $22.38~~22.99~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **Mercury Vapor** | 093 | 175 (7,000 Lumens) | $13.07~~13.43~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 095 | 400 (20,000 Lumens) | $22.49~~23.11~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

| | Tariff Code | Lumens | Rate | |
|---|---|---|---|---|
| **LED** | 150 | 6,000-10,000 | $7.49~~7.70~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Post-Top Lighting Service

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **High Pressure Sodium** | 111 | 100 (9,500 Lumens) | $18.58~~19.09~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 122 | 150 (16,000 Lumens) | $29.23~~30.03~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 120 | 250 (19,000 Lumens) | $34.02~~34.96~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 126 | 400 (40,000 Lumens) | $44.66~~45.88~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **Mercury Vapor** | 099 | 175 (7,000 Lumens) | $14.99~~15.40~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

*Continued on Sheet 10-2*

# Tariff O.L. Continued
# (Outdoor Lighting)

**Post-Top Lighting Service Continued**

| | Tariff Code | Lumens | Rate | |
|---|---|---|---|---|
| **LED** | 160 | 6,000-10,000 | $21.56~~22.15~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits. Incremental costs of installation beyond thirty feet shall be the responsibility of the customer.

C. Flood Lighting Service

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **High Pressure Sodium** | 107 | 200 (22,000 Lumens) | $16.27~~16.72~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 109 | 400 (50,000 Lumens) | $23.76~~24.41~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

| | Tariff Code | Watts | Rate | |
|---|---|---|---|---|
| **Metal Halide** | 110 | 250 (20,500 Lumens) | $19.74~~20.29~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 116 | 400 (36,000 Lumens) | $24.87~~25.55~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 131 | 1,000 (110,000 Lumens) | $45.27~~46.51~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 130 | 250 Mongoose (20,500 Lumens) | $25.75~~26.46~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 136 | 400 Mongoose (36,000 Lumens) | $31.43~~32.29~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

| | Tariff Code | Lumens | Rate | |
|---|---|---|---|---|
| **LED** | 165 | 17,500-22,500 | $28.00~~28.77~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |
| | 166 | 42,500-47,500 | $34.40~~35.34~~ | per lamp + 0.02612 x kWh in Sheet No. 10-4 |

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

D. LED Lamp Conversion Charge
Existing outdoor lighting customers that wish to convert from non-LED lamps to new LED fixtures shall pay a monthly charge of $3.33 per lamp replaced, per month for 84 months.

*All lumen figures are based upon manufacturer estimates and may vary.*

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

| | | |
|---|---|---|
| Wood Pole | $4.08~~4.20~~ | per month |
| Overhead wire span not over 150 feet | $2.26~~2.33~~ | per month |
| Underground wire lateral not over 50 feet | $7.66~~7.87~~ | per month |

(Price includes pole riser and connections)

*Continued on Sheet 10-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff O.L. Continued
# (Outdoor Lighting)

E. Flexible Lighting Option *(Tariff Code 175 for Unmetered and Tariff Code 201 for Metered)*
Applicable for the installation of any outdoor area lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use if it is not metered. The Company reserves the right to refuse service under this provision based on customer's creditworthiness.

**Rate**
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.42~~1.43~~% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Monthly maintenance charge is $0.80 per lamp per month
Monthly non-fuel charge is .08561~~.08698~~ $/kWh
Base fuel charge is 0.02612 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

*Continued on Sheet 10-4*

# Tariff O.L. Continued
# (Outdoor Lighting)

| | Metal Halide | | | Mercury Vapor | | High Pressure Sodium | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 250 Watts | 400 Watts | 1,000 Watts | 175 Watts | 400 Watts | 100 Watts | 150 Watts | 200 Watts | 250 Watts | 400 Watts |
| **Jan** | 127 | 199 | 477 | 91 | 199 | 51 | 74 | 106 | 130 | 210 |
| **Feb** | 106 | 167 | 400 | 76 | 167 | 43 | 62 | 89 | 109 | 176 |
| **Mar** | 106 | 167 | 400 | 76 | 167 | 43 | 62 | 89 | 109 | 176 |
| **Apr** | 90 | 142 | 340 | 65 | 142 | 36 | 53 | 76 | 93 | 150 |
| **May** | 81 | 127 | 304 | 58 | 127 | 32 | 47 | 68 | 83 | 134 |
| **Jun** | 72 | 114 | 272 | 52 | 114 | 29 | 42 | 61 | 74 | 120 |
| **Jul** | 77 | 121 | 291 | 55 | 121 | 31 | 45 | 65 | 79 | 128 |
| **Aug** | 88 | 138 | 331 | 63 | 138 | 35 | 51 | 74 | 90 | 146 |
| **Sep** | 96 | 152 | 363 | 69 | 152 | 39 | 57 | 81 | 99 | 160 |
| **Oct** | 113 | 178 | 427 | 81 | 178 | 45 | 66 | 95 | 116 | 188 |
| **Nov** | 119 | 188 | 449 | 86 | 188 | 48 | 70 | 100 | 122 | 198 |
| **Dec** | 129 | 203 | 486 | 92 | 203 | 52 | 75 | 108 | 132 | 214 |
| **Total** | 1,204 | 1,896 | 4,540 | 864 | 1,896 | 484 | 704 | 1,012 | 1,236 | 2,000 |

| | Light Emitting Diode (LED) | | | |
|---|---|---|---|---|
| | 150 Tariff Code 6,000-10,000 Lumens | 160 Tariff Code 6,000-10,000 Lumens | 165 Tariff Code 17,500-22,500 Lumens | 166 Tariff Code 42,500-47,500 Lumens |
| **Jan** | 28 | 33 | 75 | 154 |
| **Feb** | 24 | 28 | 63 | 129 |
| **Mar** | 24 | 28 | 63 | 129 |
| **Apr** | 20 | 24 | 53 | 109 |
| **May** | 18 | 21 | 48 | 96 |
| **Jun** | 16 | 19 | 43 | 87 |
| **Jul** | 17 | 20 | 46 | 93 |
| **Aug** | 19 | 23 | 52 | 105 |
| **Sep** | 22 | 26 | 58 | 118 |
| **Oct** | 25 | 30 | 67 | 136 |
| **Nov** | 27 | 32 | 71 | 145 |
| **Dec** | 29 | 33 | 77 | 156 |
| **Total** | 269 | 317 | 716 | 1,457 |

*Continued on Sheet 10-5*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff O.L. Continued
# (Outdoor Lighting)

**Hours of Lighting**
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

**Ownership of Facilities**
All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

**Term of Initial Service**
Term of initial service shall be required for a period of one year. If early termination is requested or service is terminated during the initial 12 month period, the customer will be billed for the remainder of the 12 month period on the final bill.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

Customer's account balance must be current prior to installation of new or additional lights.

# Tariff S.L.
# (Street Lighting)

**Availability of Service**
Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium lamps shall cease on January 14, 2021.

**Base Fuel Rate**
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

**Rate** *(Tariff Code 528)*

A. Overhead Service on Existing Distribution Poles

| | Watts | Rate | |
|---|---|---|---|
| High Pressure Sodium | 100 (9,500 Lumens) | $8.64~~8.49~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 150 (16,000 Lumens) | $9.49~~9.32~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 200 (22,000 Lumens) | $11.24~~11.04~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 400 (50,000 Lumens) | $14.76~~14.50~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

| | Lumens | Rate | |
|---|---|---|---|
| LED | 8,000-11,000 | $9.89~~9.71~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 10,000-14,000 | $12.70~~12.48~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 24,000-30,000 | $15.14~~14.87~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 6,000-10,000 | $10.27~~10.09~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 8,000-12,000 | $22.78~~22.38~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Flood 17,500-22,500 | $16.67~~16.38~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

B. Service on New Wood Distribution Poles

| | Watts | Rate | |
|---|---|---|---|
| High Pressure Sodium | 100 (9,500 Lumens) | $13.51~~13.27~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 150 (16,000 Lumens) | $14.47~~14.22~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 200 (22,000 Lumens) | $16.23~~15.94~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 400 (50,000 Lumens) | $20.83~~20.46~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

| | Lumens | Rate | |
|---|---|---|---|
| LED | 8,000-11,000 | $16.30~~16.01~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 10,000-14,000 | $19.12~~18.79~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 24,000-30,000 | $21.57~~21.19~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 6,000-10,000 | $16.68~~16.39~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 8,000-12,000 | $29.20~~28.69~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Flood 17,500-22,500 | $23.10~~22.69~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

*Continued on Sheet 11-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff S.L. Continued
# (Street Lighting)

C. Service on New Metal or Concrete Poles*

| | Watts | Rate | |
|---|---|---|---|
| High Pressure Sodium | 100 (9,500 Lumens) | $28.15~~27.65~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 150 (16,000 Lumens) | $29.17~~28.66~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 200 (22,000 Lumens) | $30.93~~30.38~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 400 (50,000 Lumens) | $34.45~~33.84~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

| | Lumens | Rate | |
|---|---|---|---|
| LED | 8,000-11,000 | $28.49~~27.99~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 10,000-14,000 | $30.40~~29.86~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | 24,000-30,000 | $31.90~~31.34~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 6,000-10,000 | $29.34~~28.82~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Post Top 8,000-12,000 | $41.70~~40.97~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |
| | Flood 17,500-22,500 | $33.39~~32.80~~ | per lamp + 0.02612 x kWh in Sheet No. 11-3 |

* Effective June 29, 2010 and thereafter these lamps are not available for new installations

D. LED Lamp Conversion Charge

Existing street lighting customers that wish to convert from non-LED lamps to a new LED fixture shall pay a monthly charge of $2.18 per lamp replaced, per month for 84 months.

*All lumen figures are based upon manufacturer estimates and may vary.*

E. Flexible Lighting Option *(Tariff Code 525 for Unmetered and Tariff Code 526 for Metered)*
Applicable for the installation of any street lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use unless the system is separately metered. The Company reserves the right to refuse service under this provision based on customer's credit worthiness.

**Rate**
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.04% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Monthly maintenance charge is $2.52 per lamp per month
Monthly non-fuel charge is .05192~~.05261~~ $/kWh
Base fuel charge is 0.02612 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

*Continued on Sheet 11-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff S.L. Continued
# (Street Lighting)

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

For adjustments calculated on a per kWh basis the following kWh values will be used in the calculation:

| | **High Pressure Sodium** | | | | **Light Emitting Diode (LED)** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 100 Watts | 150 Watts | 200 Watts | 400 Watts | 8,000-11,000 Lumens | 10,000-14,000 Lumens | 24,000-30,000 Lumens | Post Top 6,000-10,000 Lumens | Post Top 8,000-12,000 Lumens | Flood 17,500-22,500 Lumens |
| **Jan** | 51 | 74 | 106 | 210 | 35 | 49 | 98 | 33 | 48 | 75 |
| **Feb** | 43 | 62 | 89 | 176 | 30 | 40 | 83 | 28 | 41 | 63 |
| **Mar** | 43 | 62 | 89 | 176 | 30 | 40 | 83 | 28 | 41 | 63 |
| **Apr** | 36 | 53 | 76 | 150 | 25 | 34 | 70 | 24 | 34 | 53 |
| **May** | 32 | 47 | 68 | 134 | 22 | 30 | 62 | 21 | 31 | 48 |
| **Jun** | 29 | 42 | 61 | 120 | 20 | 27 | 56 | 19 | 27 | 43 |
| **Jul** | 31 | 45 | 65 | 128 | 21 | 29 | 60 | 20 | 29 | 46 |
| **Aug** | 35 | 51 | 74 | 146 | 23 | 33 | 68 | 23 | 32 | 52 |
| **Sep** | 39 | 57 | 81 | 160 | 27 | 37 | 75 | 26 | 37 | 58 |
| **Oct** | 45 | 66 | 95 | 188 | 31 | 43 | 87 | 30 | 43 | 67 |
| **Nov** | 48 | 70 | 100 | 198 | 33 | 46 | 93 | 32 | 45 | 71 |
| **Dec** | 52 | 75 | 108 | 214 | 36 | 50 | 100 | 33 | 50 | 77 |
| **Total** | 484 | 704 | 1,012 | 2,000 | 333 | 458 | 935 | 317 | 458 | 716 |

**Special Facilities**
When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

*Continued on Sheet 11-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff S.L. Continued
# (Street Lighting)

**Hours of Lighting**
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

**Term of Contract**
Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

**Special Terms and Conditions**
A customer's account balances must be current prior to installation of new or additional lights.

# Tariff P.A.
# (Pole Attachments)

**1. Availability of Service**

Available to broadband internet providers, cable television system operators, governmental units and telecommunications carriers that provide service within the operating area of Kentucky Power Company (Company). This Tariff is not available to: (1) the Attachments of utilities, including local exchange carriers (LECs), that have joint use agreements with Company; or (2) macro cell facilities. Nothing in this Tariff expands the right to attach to Company's facilities beyond the rights otherwise conveyed by law.

**2. Definitions**

Unless stated otherwise, the terms used in this Tariff shall have the same meaning as the terms expressly defined in Section 1 of 807 KAR 5:015.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means a Wireline Facility or Wireless Facility and all associated equipment, including without limitation, any overlashed cable or fiber, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases or other equipment that impedes accessibility or otherwise conflicts with Company's standards. For billing purposes, the term "Attachment" also includes: (1) a Service Drop affixed to a pole that is located more than one (1) vertical foot away from the point at which the messenger strand is attached to the pole; and (2) a Service Drop located on a dedicated service, drop or lift pole.

"Communications Space" means the area on a pole below the Communications Worker Safety Zone and above the point on the pole necessary to meet NESC clearance, department of transportation or other governmental requirements, and Company's construction standards.

"Facility" means any Company Distribution Pole, right-of-way, conduit or duct normally used by Company to support or protect its electric conductors. The term "Facility" does not include any Transmission Pole.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69kV, but does not include a pole used primarily to support outdoor lighting.

"NESC" means the National Electrical Safety Code.

"Larger Order" means an application, or multiple applications submitted within thirty (30) days of one another, seeking to make Attachments to more than three hundred (300) poles.

"Operator" means a broadband internet provider, cable television system operator, governmental unit or telecommunications carrier.

"Overlashing" means the practice whereby an entity, whether Operator or a third party, physically connects or attaches, through lashing or otherwise, new fiber optic or coaxial cable, or any other type of cable, to an existing Wireline Attachment on a Distribution Pole.

"Service Drop" means a Wireline Facility, attached to a pole with a J-hook or other similar hardware, that connects the trunk line to an end user's premises, and extends directly from the trunk line to a drop/lift pole or into an end user's premises.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69kV or greater.

"Wireline Facility" means fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

*Continued on Sheet 12-2*

# Tariff P.A. Continued
# (Pole Attachments)

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Operator's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's standards. The term "Wireless Facility" does not include any strand-mounted antennas or macro cell facilities.

**3. Rate**

| | | |
|---|---|---|
| Charge for Wireline Facility on a two-user pole | $10.82 | per attachment per year |
| Charge for Wireline Facility on a three-user pole | $6.71 | per attachment per year |

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost x Usage Factor x Carrying Charge = Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party.

| | | |
|---|---|---|
| Charge for Attachments within ducts or conduits | $2.70 | per linear foot per year |
| Charge for attachment of Wireless Facility to top of Distribution Pole | $150 | per attachment per year |
| Charge for attachment of Wireless Facility within Communications Space of Distribution Pole | $75 | per attachment per year |

The above rates are subject to revision from time to time as approved by the Commission.

**4. Company Facilities Subject to Attachment**

Pursuant to 807 KAR 5:015 and the terms and conditions of this Tariff, Attachments to Company Facilities that do not interfere with Company's electric service requirements shall be permitted. Company may deny access to any Company Facility on a non-discriminatory basis where there is insufficient capacity or for reasons of safety, reliability, and generally applicable engineering purposes.

All Company Facilities covered by this Tariff remain the property of Company regardless of any payment by Operator toward their cost. No use, however extended, of Company Facilities or payment of any fee or charge required hereunder shall create or vest in Operator any claim or right, possession, title, interest or ownership in such Facilities. Nothing in this Tariff shall be construed to obligate Company to construct, reconstruct, retain, extend, repair, place, replace or maintain any Facility which, in Company's sole discretion, is not needed for Company's own purposes. Company and its successors and assigns shall have the right to operate, relocate and maintain Company Facilities in such a manner as will best enable Company, in its sole discretion, to fulfill its service requirements.

**5. Company's Pole Attachment Policy Handbook**

Operator is expected to follow the processes and guidelines set forth in Company's Pole Attachment Policy handbook, as well as any amendments thereto, but only to the extent that such processes and guidelines do not conflict with 807 KAR 5:015 or this Tariff.

*Continued on Sheet 12-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.A. Continued
# (Pole Attachments)

**6. Applications**

When Operator proposes to furnish service within Company's operating area and desires to make Attachments to Company Facilities, Operator shall make written application to install such Attachments, in the format required by Company, that specifies the location of each Facility in question, the character of its proposed Attachments, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed Attachment and any other attachments or equipment attached to the Facility. If Operator's application qualifies as a Larger Order, Operator shall provide Company at least sixty (60) days' advance written notice before submission to Company. Company will notify Operator, within ten (10) days of receipt of an application, if the application is incomplete. If the application is incomplete, Operator shall provide the additional information required by Company prior to Company's review of the application on its merits.

If Operator is only seeking to make Wireline Attachments to Distribution Poles, Company shall complete a make-ready survey within forty-five (45) days (or within sixty (60) days in the case of a Larger Order) of receipt of a complete application. Company may, in its sole discretion, require prepayment for a make-ready survey. The current per pole estimate for a make-ready survey is $275. If the actual cost of performing the make-ready survey exceeds the amount of Operator's prepayment, then Operator shall reimburse Company for any difference upon receipt of an invoice for such amount. If the actual cost of performing the make-ready survey is less than the amount of Operator's prepayment, then Company shall issue Operator a refund for the difference. Company shall use commercially reasonable efforts to provide at least five (5) days advance notice of a field inspection to Operator and any other affected third party. If Operator submits a make-ready survey with an application, Company may elect to utilize the survey by: (1) notifying the affected third parties of its intent to use the make-ready survey performed by Operator; and (2) providing the affected third parties with a copy of the make-ready survey within the deadline set forth above for completing a make-ready survey.

Within forty-five (45) days (or within sixty (60) days in the case of Larger Orders) after receipt of a complete application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Within fourteen (14) days of providing such notice, Company shall provide Operator with a statement of the costs for any necessary Company make-ready work, including the cost of rearranging Company's electric supply facilities or pole changeouts. Operator shall indicate its approval of the make-ready cost statement by submitting payment to Company within fourteen (14) days of receipt of the make-ready cost statement. If payment is not received by Company within fourteen (14) days, then Company's make-ready cost statement shall be deemed withdrawn. Within seven (7) days of receipt of Operator's payment, Company shall notify, in a manner consistent with applicable law, all third parties whose attachments might be affected by the make-ready, and thereafter provide Operator with the contact information for, and copies of the notices sent to, such third parties. Thereafter, Operator shall be responsible for coordinating the rearrangement or transfer of any third-party attachment and shall pay the costs related thereto.

Operator shall reimburse Company for any expenses incurred in reviewing Operator's written applications for attachment. Operator shall have a non-exclusive right to use such Facilities of Company as may be used or reserved for use by Operator and any other Facilities of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant to others, by contract or otherwise, rights or privileges to use any Facilities of Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted.

*Continued on Sheet 12-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.A. Continued
# (Pole Attachments)

**7. Standards for Installation**

All Attachments and associated equipment of Operator shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the Facilities covered by this Tariff. All such Attachments and equipment shall be installed and at all times maintained by Operator so as to comply with the standards set forth in Company's Pole Attachment Policy handbook, the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction thereover. In the event of a conflict, the more stringent standard shall apply. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

Operator shall complete the installation of its Attachments within thirty (30) days of Company's approval of the application for such Attachments, or if make-ready is required to accommodate the Attachments, the completion date of such make-ready. Operator shall, within seven (7) days after completing the installation of its Attachments, provide Company with written notice of such completion, and Company shall have the right to perform a post-inspection on such Attachments, at Operator's sole expense, within ninety (90) days of receipt of Operator's notice of completion. If Company's inspection reveals that Operator's installation resulted in any property damage or code violations, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

**8. Tagging Requirement**

Operator shall identify each of its Attachments with a tag, approved in advance by Company, that includes Operator's name, 24-hour contact telephone number, and such other information as Company may require. Operator shall tag an Attachment at the time of construction. Any untagged Attachment existing as December 28, 2022 shall be tagged by Operator by no later than December 31, 2024.

**9. Overlashing**

Operator shall provide Company with at least thirty (30) days' advance written notice before Overlashing, or allowing a third party to overlash, Operator's existing Wireline Facilities. Operator is responsible for all Overlashing performed on its Wireline Facilities, including any Overlashing by a third party, and shall ensure that all Overlashing complies with Company's standards, the applicable provisions of the NESC, and any other applicable law or code. If Overlashing of Operator's Wireline Facilities results in any damage to the pole, Company equipment or existing Attachments, or if any Overlashing causes a safety or engineering standard violation, Operator shall be responsible, at its expense, for any necessary repairs or corrections.

Operator shall notify Company within fifteen (15) days of completion of an overlash on a particular pole. Within ninety (90) days of receiving such notice, Company will perform an inspection at Operator's expense to determine whether the overlash caused any damage to Company property or resulted in any code violations. Company shall notify Operator of any damage to Company property or code violations within fourteen (14) days after completion of the inspection. At Company's discretion, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

*Continued on Sheet 12-5*

# Tariff P.A. Continued
# (Pole Attachments)

**10. Pole Installation or Replacement; Rearrangements; Guying**

In any case Operator proposes to install Attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such Attachments such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or shared ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed Attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed Attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of transferring each of their respective facilities or attachments to the newly-installed pole.

If Operator's desired Attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon or of any other person, or if because of Operator's proposed Attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company intends to replace an existing pole on which Operator has any Attachment, or Company intends to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's Attachment, or if as a result of any inspection of Operator's Attachments Company determines that any such Attachments are not in accordance with Company's standards, applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than sixty (60) days' notice of such proposed replacement or change, or any such violation or hazard; provided, however, that the sixty (60) day notice requirement shall not apply to: (1) make-ready notices pursuant to Section 4 of 807 KAR 5:015; (2) routine maintenance by Company; or (3) a replacement or change made by Company in response to an emergency. In such event, Operator shall at its expense relocate, rearrange or modify its Attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the Attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

**11. Self-Help Remedy**

If Company is unable to meet the timelines in 807 KAR 5:015 for completing a survey or completing make-ready work above the Communications Space, and if Company lacks good and sufficient cause to deviate from such timelines, Operator may perform such work at its own expense using an Approved Contractor. Operator shall refer to Company's Pole Attachment Policy on Company's website for a list of Approved Contractors for specified purposes. Self-help is not available for pole replacements or for surveys or make-ready related to ducts. Operator shall provide written notice to Company at least one (1) week prior to performing surveys or make-ready above the Communications Space. Operator shall notify Company immediately if a survey or make-ready causes any property damage or an outage that is reasonably likely to interrupt Company's services.

*Continued on Sheet 12-6*

# Tariff P.A. Continued
# (Pole Attachments)

**12. One-Touch Make-Ready**
For Attachments to Distribution Poles that require only “simple make-ready,” as that term is defined in 807 KAR 5:015, Operator may elect to proceed with the one-touch make-ready (OTMR) process established in this Section 12, as opposed to the standard process set forth in Section 6 of this Tariff. To elect OTMR, Operator must clearly indicate in its application that it is electing the OTMR process. Operator shall not combine requests for “simple make-ready” and “complex make-ready,” as those terms are defined in 807 KAR 5:015, within an OTMR application. Operator’s OTMR application shall identify the “simple make-ready” that it intends to perform.

Company shall, within ten (10) days of receipt, determine whether Operator’s OTMR application is complete. Upon receipt of a complete OTMR application, Company shall review such application on the merits within the timelines established by 807 KAR 5:015. If Company denies an OTMR application on the merits, Company will provide Operator with an explanation of its denial, along with information and documentation supporting Company’s decision.

Operator shall be responsible for all surveys required as part of the OTMR process. Any survey performed under the OTMR process shall be conducted by an Approved Contractor. Operator shall provide Company, as well as any third parties with attachments on Distribution Poles subject to an OTMR application, at least five (5) days’ advance written notice of any field inspection, and such notice shall: provide the date, time and location of the field inspection; and state the name of the Approved Contractor that will be performing the field inspection. Operator shall allow Company and affected third parties to be present for any field inspection it performs under the OTMR process.

If Operator’s OTMR application is approved, Operator may, after providing fifteen (15) days’ advance written notice to Company and affected third parties, proceed with the make-ready. Operator’s notice shall: provide the date, time and location of the make-ready; describe the make-ready involved; and identify the contractor that will be performing the make-ready. Operator shall allow Company and affected third parties to be present during the make-ready. Operator shall complete all make-ready within thirty (30) days of the date on which Company approved Operator’s OTMR application (or within seventy-five (75) days in the case of a Larger Order), or Operator’s OTMR application will be deemed closed.

If Company or Operator determine at any time that make-ready does not qualify as “simple make-ready,” Operator shall halt all make-ready on the impacted Distribution Poles. The make-ready on the impacted Distribution Poles shall thereafter be subject to the requirements of Section 6 of this Tariff. Operator shall notify Company and affected third parties within fifteen (15) days of completion of the make-ready identified in the OTMR application.

**13. Pole Inspection**
Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company’s Facilities. In addition, Company’s right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

**14. Transfer of Attachments to New Poles**
Operator shall transfer its Attachments within sixty (60) days of receiving notice from Company (Transfer Period). If Operator fails to transfer its Attachments within the Transfer Period, Company may transfer the Attachments at Operator’s sole risk and expense. Company may transfer Operator’s Attachments prior to the expiration of the Transfer Period if an expedited transfer is necessary for safety or reliability purposes.

*Continued on Sheet 12-7*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.A. Continued
# (Pole Attachments)

**15. Attachment Inventory**
Owner may conduct a complete field inventory for the purpose of verifying the number and location of Operator's Attachments on Company Facilities. Company shall provide Operator with at least thirty (30) days' prior notice of a field inventory, and Operator shall advise Company whether Operator desires to participate in the field inventory not less than fifteen (15) days prior to the scheduled date of such inventory. Operator shall reimburse Company for the costs Company incurs in performing the field inventory, regardless of whether Operator elects to participate in the inventory; provided, however, Company may not charge Operator for more than one (1) field inventory within a five (5) year period. If Company inspects the Attachments of more than one Operator during a field inventory, then each Operator whose Attachments were inspected by Company during the field inventory shall share pro rata in the costs of such inventory. Upon request, Company shall furnish a summary report for the field inventory within a reasonable time after its completion.

If a field inventory reveals that the number of Operator's Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be unauthorized attachments and handled in accordance with Section 16.

**16. Unauthorized Attachments**
If Operator makes an Attachment that requires approval by, or advance notice to, Company under this Tariff, and if Operator fails to comply with such approval or notice requirements, then Operator's Attachment shall be deemed an unauthorized attachment. Unless Operator can demonstrate to Company's reasonable satisfaction that an unauthorized attachment was made more recently, unauthorized attachments are presumed to have existed on Company Facilities for two (2) years. Operator shall be liable for all charges and fees that would have been due under the Tariff for this time period. In addition to charges and fees applicable to the period of unauthorized attachment, Operator shall pay a penalty in the amount of: (1) $25 for each unauthorized attachment within the Communications Space on a Distribution Pole; (2) $500 for each unauthorized attachment above the Communications Space on a Distribution Pole; and (3) $500 for each unauthorized attachment within a duct. Operator shall submit an application for approval of any unauthorized attachment within sixty (60) days of the Attachment's discovery. If Operator fails to submit the required application or to comply with Company's application process, Company may remove the unauthorized attachment at Operator's sole risk and expense.

**17. Abandonment by Operator**
Operator may at any time abandon the use of a Company Facility hereunder by removing therefrom all of its Attachments and by giving written notice thereof, on a form provided by Company, and no Facility shall be considered abandoned until such notice is received. If notice has been given that Attachment(s) have been removed, but the Attachments are later discovered not to have been removed, then such Attachments shall be deemed unauthorized attachments and handled in accordance with Section 16 of this Tariff.

**18. Indemnity**
Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the Attachments and other facilities of Operator on the Facilities of Company under this Tariff, or to any such act or omission of Operator's respective representatives, employees, agents or contractors.

**19. Limitation of Liability**
IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER THIS TARIFF TO OPERATOR FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH THIS TARIFF, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE; (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE OSSIBILITY OF SUCH DAMAGES OR (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPSON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 19 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER THIS TARIFF.

*Continued on Sheet 12-8*

# Tariff P.A. Continued
# (Pole Attachments)

**20. Insurance**
Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $5,000,000 for any one occurrence.
(b) Comprehensive property damage liability insurance in an amount not less than $5,000,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making Attachments to Company's Facilities, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company thirty (30) days' prior written notice of any cancellation of or material change in such policies.

**21. Performance Assurance**
Operator shall furnish Performance Assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by Company under this Tariff, including the removal of Attachments upon termination of any license hereunder:

| Number of Attachments | Amount per Attachment | Maximum Total |
|---|---|---|
| 1-7,500 | $20 | $150,000 |
| 7,501-15,000 | $10 | $225,000 |
| 15,001+ | $5 | $1,000,000 |

The above-stated amounts are incremental. By way of example, 10,000 Attachments would require Performance Assurance in the amount of $175,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment for the next 2,500 Attachments); 20,000 Attachments would require Performance Assurance in the amount of $250,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment the next 7,500 Attachments; and $5 per Attachment for the last 5,000 Attachments).
The amount of the Performance Assurance shall be calculated by Company annually based on Operator's then-existing number of Attachments. Operator shall provide the Performance Assurance within thirty (30) days of its request by Company.
If Operator proposes to attach a Wireless Facilities to Company Facilities, Operator shall post Performance Assurance in the amount of $1,500 for each Company Facility to which a Wireless Facility is attached. The amount of the Performance Assurance shall not be reduced upon completion of installation or other event.

In the event the Operator provides Performance Assurance in the form of a surety bond or letter of credit, each bond or letter of credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or letter of credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or letter of credit, Company shall request Operator to immediately remove its Attachments and all other equipment from Company Facilities. If Operator should fail to complete the removal of all of its Attachments from Company Facilities within sixty (60) days after receipt of such request, then Company may remove Operator's Attachments at Operator's expense and without liability for any damage to Operator's Attachments.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- and/or letter of credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

*Continued on Sheet 12-9*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.A. Continued
# (Pole Attachments)

**22. Easements**
Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of Attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said Attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said Attachments on Company's poles.

**23. Charges and Fees**
Operator agrees to pay Company an annual charge per Attachment as set forth in Section 3 of this Tariff in advance, and such other charges as may be provided for herein, for the use of each of Company Facility, any portion of which is occupied by, or reserved at Operator's request for, the Attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial Attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make Attachments.

**24. Fees for Additional Attachments**
For Attachments made to Company Facilities between billing dates, Operator shall be billed a prorated amount of the annual charge effective on the date of attachment in on the Operator's next bill. Company will not reimburse Operator for, or otherwise prorate Operator's next bill for, any Attachments removed from Company Facilities between billing dates.

**25. Payment**
Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due thirty (30) days from the date of the invoice therefor. all amounts not so paid shall accrue interest at a monthly simple interest rate of 1.5% . Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company may, in its sole discretion, invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

**26. Default or Non-Compliance**
If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within sixty (60) days, after written notice from Company to correct such default or non-compliance, Company may, in addition to all other remedies under this Tariff, take any one or more of the following actions: terminate the specific permit or permits covering the Company Facilities to which such default or non-compliance is applicable; remove, relocate or rearrange Attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional Attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults, terminate Operator's right of attachment. Where applicable, Company's written notice of default or non-compliance shall inform Operator of Company's right to remove, relocate or rearrange Attachments of Operator, in the event Operator fails to cure its default or non-compliance within the aforementioned 60-day period. Operator shall remove all Attachments where Company has terminated the right of attachment herein within sixty (60) days of Company providing notice of termination. If Operator fails to remove such Attachments within sixty (60) days, then Company may remove such Attachments at Operator's expense. Company shall have no obligation to store or recover any value for such removed Attachments.

No liability shall be incurred by Company because of any or all such actions except for Company's gross negligence or willful misconduct in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

*Continued on Sheet 12-10*

# Tariff P.A. Continued
# (Pole Attachments)

**27. Notices**

Any notice required by this Tariff shall be deemed properly given if sent to Company's or Operator's authorized representative using any of the following methods: (1) overnight delivery by nationally recognized courier; (2) certified U.S. mail, return receipt requested, postage prepaid; (3) electronically via telecopier or electronic mail; or (4) sent in the manner expressly required herein or by Company's standards. Operators shall, within thirty (30) days of the effective date of this Tariff, or if service is taken for the first time following the effective date of this Tariff, prior to submitting any applications for Attachments, provide Company with the following information for each of their authorized representatives: name, title, mailing address and electronic mailing address. The designation of an authorized representative, as well as the contact information for an existing authorized representative, may be changed at any time by similar notice. Operators are required to maintain current contact information with Company for each of their authorized representatives.

**28. Prior Agreements**

This Tariff, as of the effective date, terminates, supersedes and replaces any previous agreement or license affecting Company's Facilities and Operator's Attachments covered herein.

**29. Assignment**

This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

**30. Performance Waiver**

Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

**31. Preservation of Remedies**

No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

# Tariff T.S.
# (Temporary Service)

**Availability of Service**
Where capacity is available, Company will install service for temporary lighting and power service to customers who have demonstrated to the Company's satisfaction that the requested temporary service will be temporary in nature. Residential customers will be supplied with 100 amp single phase service. All other customer classes will be supplied at voltage levels applicable to the class of business.

**Rate** *(Tariff Code 019)*
Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of installation, connection, disconnection and removal of service.

**Charges**
The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

Customer's requesting temporary service will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost of installation, connection, disconnection, and removal of the required facilities to provide temporary service.

**Terms of Service**
Temporary Service will be in effect for a period of 180 days from the date of installation. The Company may grant extensions based on customer's demonstration of continued need for temporary service.

The Company may discontinue temporary service at the end of the 180 days, or at the end of any extended period of time after the initial 180 days.

**Special Terms and Conditions**
A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required. This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature. See Terms and Conditions of Service.

# Tariff U.D.C.
# (Underground Differential Cost Schedule)

## Underground Service Plan for Residential Subdivisions and Residential Service Laterals

**Applicable**
To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, and R.S.D.

**Rate**

**PRIMARY AND SECONDARY DISTRIBUTION SYSTEM**

Charge: **$ 65.29** per foot of lot width (average x number of lots) when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: **$ 31.95** per foot of lot width (average x number of lots) when Customer performs trenching, conduit installation, and backfilling to Company specifications.

**SERVICE LATERALS**

**FROM OVERHEAD FACILITIES**

Charge: **$ 29.67** per foot of trench length from Overhead Facilities when Company performs trenching, conduit installation, and backfilling to Company

Charge: **$ 11.04** per foot of trench length from Overhead Facilities when Customer performs trenching, conduit installation, and backfilling to Company

**FROM UNDERGROUND FACILITIES**

Charge: **$ 23.83** per foot of trench length from Underground Facilities when Company performs trenching, conduit installation, and backfilling to Company

Charge: **$ 5.70** per foot of trench length from Underground Facilities when Customer performs trenching, conduit installation, and backfilling to Company

**REPLACEMENT OF USEFUL OVERHEAD SERVICE DROP**

Charge: **$ 200.00** for each removal in addition to any underground differential costs.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Rider A.F.S.
# (Alternate Feed Service Rider)

**Availability of Service**
Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S.-TOD, L.G.S., L.G.S.-TOD, I.G.S., or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

**System Impact Study Charge**
The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

**Equipment and Installation Charge**
The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer’s basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

**Transfer Switch Provision**
In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company’s engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $15.75 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

*Continued on Sheet 15-2*

# Rider A.F.S. Continued
# (Alternate Feed Service Rider)

**Transfer Switch Provision Continued**

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

**Monthly AFS Capacity Reservation Demand Charge**
Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $6.38 per kW.

**AFS Capacity Reservation**
The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's average maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify Kentucky Power regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

*Continued on Sheet 15-3*

# Rider A.F.S. Continued
# (Alternate Feed Service Rider)

**Determination of Billing Demand**

Full-Load Requirement:

For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:

For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

**Terms of Contract**

The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

**Special Terms and Conditions**

This rider is subject to the Company's Terms and Conditions of Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

# Rider R.P.O.
# (Renewable Power Option Rider)

**Availability of Service**
Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W. tariffs.

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand.

**Conditions of Service**
Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers.

**Rates**

Option A
In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

| | **Block Purchase Charge ($ per 100 kWh block)** | **All Usage Purchase Charge per kWh consumed** |
|---|---|---|
| **A1. Solar RECs** | $0.50/month | $0.005 |
| **A2. Wind RECs** | $0.50/month | $0.005 |
| **A3. Hydro & Other RECs** | $0.50/month | $0.005 |

Option B
Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer.

*Continued on Sheet 16-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Rider R.P.O. Continued
# (Renewable Power Option Rider)

**Term**
This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice.

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer.

**Special Terms and Conditions**
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program.

# Tariff N.U.G.
# (Non-Utility Generator)

**Availability of Service**
This tariff is unavailable to new participants. This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by Customer's generator.

**Definitions**

**Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the Customer's generation facilities, usually when the Customer's generator is not operating. Station Power does not include Startup Power.

**Station Power Service**
Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the Customer's Station Power requirements.

**Station Contract Capacity** – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

**Transmission Service**

**Transmission Provider** - The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

**Term of Contract**
Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

*Continued on Sheet 17-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.U.G. Continued
# (Non-Utility Generator)

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide Station Power from other generation facilities, owned by the same individual business entity that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

# Tariff N.M.S.
# (Net Metering Service)

**Availability of Service**

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible electric generating facilities in service before May 15, 2021 shall be entitled to continue to take service under this tariff, as it may be amended from time to time by the Commission, until the earlier of: (i) May 14, 2046; or (ii) the date the customer's modification of the eligible electric generating facility results in a material increase in the eligible electric generating facility's capacity.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

**Metering**

Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

**Billing/Monthly Charges**

Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

*Continued on Sheet 18-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**Application and Approval Process**
The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

**Level 1 and Level 2 Definitions**

**Level 1**
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

*Continued on Sheet 18-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**Level 1 Continued**
If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

**Level 2**
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

*Continued on Sheet 18-4*

# Tariff N.M.S. Continued
# (Net Metering Service)

**Application, Inspection and Processing Fees**
No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

**Terms and Conditions for Interconnection**
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company’s Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company’s system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company‘s electric system. At all times when the generating facility is being operated in parallel with Company’s electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company’s electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company’s ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

*Continued on Sheet 18-5*

# Tariff N.M.S. Continued
# (Net Metering Service)

**Terms and Conditions for Interconnection Continued**

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

*Continued on Sheet 18-6*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**Terms and Conditions for Interconnection Continued**

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

**Term of Contract**
Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

**Special Terms and Conditions**
This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

*Continued on Sheet 18-7*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

## Application For Interconnection And Net Metering – Level 1

***Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity and 3.) connecting to Kentucky Power distribution system.***

*Submit this Application to:*

**D.G. Coordinator**
**American Electric Power**
**1 Riverside Plaza**
**Columbus, Ohio 43215-2373**
**614-716-4020 Office / 614-716-1414 Fax**
**dgcoordinator@aep.com**

**(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)**

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip: Electric Service

Account Number

*Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:*

**Alternate Contacts**

| Name | Company | Telephone/Email |
|---|---|---|
| | | |
| | | |

*Continued on Sheet 18-8*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

**Tariff N.M.S. Continued**
**(Net Metering Service)**

***APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED***

**Equipment Qualifications**

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

*Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.*

*Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.*

*Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.*

**Expected Start-up Date: _______________________**

*Continued on Sheet 18-9*

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 1:**

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

*Continued on Sheet 18-10*

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

*Continued on Sheet 18-11*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

*Continued on Sheet 18-12*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

**Effective Term and Termination Rights**

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

**Customer Signature: ________________________________________ Date: ______________________________________________**

**COMPANY APPROVAL SECTION**

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

**Company inspection and witness test: ( ) Required ( ) Waived**

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: _______________________ to schedule an inspection and witness test.

**Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed**

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

_______________________________________________________________________________________________

**Approved by**: _____________________________ **Date**:___________________________________

**Printed Name**: ____________________________**Title:** ___________________________________

*Continued on Sheet 18-13*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

## Application for Interconnection and Net Metering – Level 2

***Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).***

*Submit this Application (along with the application fee of $100) to:*

**D.G. Coordinator**
**American Electric Power**
**1 Riverside Plaza**
**Columbus, Ohio 43215-2373**
**614-716-4020 Office / 614-716-1414 Fax**
**dgcoordinator@aep.com**

**(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)**

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

*Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:*

**Alternate Contacts**

| Name | Company | Telephone/Email |
|---|---|---|
| | | |
| | | |

*Continued on Sheet 18-14*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

## APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

### Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: ______________________________________________

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

*Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.*

*Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.*

*Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.*

Expected Start-up Date: ___________________________________

*Continued on Sheet 18-15*

# Tariff N.M.S. Continued
# (Net Metering Service)

## Interconnection Agreement – Level 2

**This Interconnection Agreement** (Agreement) is made and entered into this _____ day of ___, 20__, by and between Kentucky Power Company (Company), and ________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

**Witnesseth**:

**Whereas,** Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: ______________________________________________

Generator Size and Type: ______________________________________________

**Now, Therefore,** in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

*Continued on Sheet 18-16*

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 2:**

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

*Continued on Sheet 18-17*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

*Continued on Sheet 18-18*

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

*Continued on Sheet 18-19*

# Tariff N.M.S. Continued
# (Net Metering Service)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

**Effective Term and Termination Rights**

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

| | | | |
|---|---|---|---|
| **Customer Signature:** | ______________________________ | **Date:** | ______________________________ |
| **Printed Name:** | ______________________________ | **Title:** | ______________________________ |
| **Company Signature:** | ______________________________ | **Date:** | ______________________________ |
| **Printed Name:** | ______________________________ | **Title:** | ______________________________ |

*Continued on Sheet 18-20*

## Tariff N.M.S. Continued
## (Net Metering Service)

### Interconnection Agreement – Level 2
### Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.

- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.

- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

# Tariff N.M.S. II
# (Net Metering Service II)

**Availability of Service**
Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible generating facilities may take service, for a period of 25 years after the eligible generating facility is first placed in service, under the two-part rate structure and netting periods of this tariff in effect at the time the eligible electric generating facility is first placed in service.

Customers served under this optional offering will not be eligible for the Company's Equal Payment Plan (Budget) or Average Monthly Payment Plan (AMP).

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

**Metering**
Net energy metering shall be accomplished using a time of use ("TOU") kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

**Billing Charges**
All net billing kWh and kW in each netting period, accumulated for the billing period, shall be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill.

All excess customer generation, (net negative energy or "NNE"), accumulated for the billing period, shall be credited at the avoided cost rate of 0.09746 $/kWh for Residential service and 0.09657 $/kWh for non-residential service each billing period.

Bill credits to customers for NNE at the avoided cost rate each billing period is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed energy charges, along with any riders that are based on a per kWh charge, during the billing period, the amount in excess will be carried over for use in subsequent billing periods.

*Continued on Sheet 19-2*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**Application and Approval Process**
The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

**Level 1 and Level 2 Definitions**

**Level 1**
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

*Continued on Sheet 19-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**Level 1 Continued**
If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

**Level 2**
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

*Continued on Sheet 19-4*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**Level 2 Continued**
The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

**Application, Inspection and Processing Fees**
No application fee or other review, study, or inspection or witness test fees will be charged by the Company for Level 1 applications.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $100. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

**Terms and Conditions for Interconnection**
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard TOU metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

*Continued on Sheet 19-5*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**Terms and Conditions for Interconnection Continued**

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company‘s electric system. At all times when the generating facility is being operated in parallel with Company’s electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company’s electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company’s ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer’s sole cost and expense, the generating facility from any condition or disturbance on Company’s electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer’s side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer’s energy generating equipment from Company’s electric service under the full rated conditions of the customer’s generating facility. The external disconnect switch (EDS) shall be located adjacent to Company’s meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company’s safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company‘s sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company’s electric system creates or contributes (or may create or contribute) to a system emergency on either Company’s or customer’s electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company’s electric system; or (c) the generating facility interferes with the operation of Company’s electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer’s entire facility.

*Continued on Sheet 19-6*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**Terms and Conditions for Interconnection Continued**

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

**Term of Contract**

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

**Special Terms and Conditions**

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

*Continued on Sheet 19-7*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## Application For Interconnection And Net Metering – Level 1

***Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity, and 3.) connecting to Kentucky Power distribution system.***

*Submit this Application to:*

**D.G. Coordinator American Electric Power**
**1 Riverside Plaza**
**Columbus, OH 43215-2373**
**614-716-4020 Office / 614-716-1414 Fax**
dgcoodinator@aep.com

**(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)**

Applicant

Name: ____________________

Mailing Address: ____________________

City: ____________ State: ____________ Zip: ____________

Phone: ( ) Phone: ( )

E-mail address: ____________________

Service Location

Name: ____________________

Street Address: ____________________

City: ____________ State: ____________ Zip: ____________

Electric Service Account Number ____________________

*Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:*

**Alternate Contacts**

| Name | Company | Telephone/Email |
|---|---|---|
| | | |
| | | |

*Continued on Sheet 19-8*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## *APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED*

**Equipment Qualifications**

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

*Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.*

*Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.*

*Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.*

**Expected Start-up Date: ________________________**

*Continued on Sheet 19-9*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 1:**

1 The Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

*Continued on Sheet 19-10*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

*Continued on Sheet 19-11*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits ("RECs") that may be generated by their generating facility.

*Continued on Sheet 19-12*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 1, continued**

**Effective Term and Termination Rights**

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

**Customer Signature:** ______________________________ **Date:** ______________________

**COMPANY APPROVAL SECTION**

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

**Company inspection and witness test: ( ) Required ( ) Waived**

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: to schedule an inspection and witness test.

**Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed**

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

______________________________________________________________

**Approved by**: ______________________________ **Date**: ______________________

**Printed Name**: ______________________________ **Title:** ______________________

*Continued on Sheet 19-13*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## Application for Interconnection and Net Metering – Level 2

***Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).***

*Submit this Application (along with the application fee of $100) to:*

**D.G. Coordinator**
**American Electric Power**
**1 Riverside Plaza**
**Columbus, Ohio 43215-2373**
**614-716-4020 Office / 614-716-1414 Fax**
**dgcoordinator@aep.com**

**(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)**

Applicant

Name: ______________________________

Mailing Address: ______________________________

City: __________ State: __________ Zip: __________

Phone: (______) Phone: (______________________)

E-mail address: ______________________________

Service Location

Name: ______________________________

Street Address: ______________________________

City: __________ State: __________ Zip: __________

Electric Service Account Number ______________________________

*Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:*

**Alternate Contacts**

| Name | Company | Telephone/Email |
|---|---|---|
| | | |
| | | |

*Continued on Sheet 19-14*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

### Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility:

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

*Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.*

*Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.*

*Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.*

Expected Start-up Date: ________________________________

*Continued on Sheet 19-15*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## Interconnection Agreement – Level 2

**This Interconnection Agreement** (Agreement) is made and entered into this _____ day of __, 20__, by and between Kentucky Power Company (Company), and ________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

**Witnesseth**:

**Whereas,** Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location:_____________________________________________________________

Generator Size and Type:________________________________________________

**Now, therefore,** in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

*Continued on Sheet 19-16*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 2:**

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

*Continued on Sheet 19-17*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company’s electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company’s safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS
   be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

*Continued on Sheet 19-18*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity are allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

*Continued on Sheet 19-19*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff N.M.S. II Continued
# (Net Metering Service II)

**TERMS AND CONDITIONS FOR LEVEL 2, continued**

**Effective Term and Termination Rights**

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

**Customer Signature:** ______________________________ **Date:** ______________

**Printed Name:** ______________________________ **Title:** ______________

**Company Signature:** ______________________________ **Date:** ______________

**Printed Name:** ______________________________ **Title:** ______________

*Continued on Sheet 19-20*

# Tariff N.M.S. II Continued
# (Net Metering Service II)

## Interconnection Agreement – Level 2
## Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.

- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.

- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

# Tariff COGEN/SPP I
# (Cogeneration and/or Small Power Production--100 KW or Less)

**Availability of Service**

This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

**Monthly Charges for Delivery from the Company to the Customer**

Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

**Additional Charges**

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

| | Single Phase | Polyphase |
|---|---|---|
| Standard Measurement | $9.25 | $12.10 |
| T.O.D. Measurement | $9.85 | $12.40 |

*Continued on Sheet 20-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff COGEN/SPP I Continued
# (Cogeneration and/or Small Power Production--100 KW or Less)

**Additional Charges Continued**

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

**Monthly Credits or Payments for Energy and Capacity Deliveries**

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

| | |
|---|---|
| Standard Meter – All KWH | Variable LMP at time of delivery ¢ KWH |
| T.O.D. Meter | |
| On-Peak KWH | Variable LMP at time of delivery ¢ KWH |
| Off-Peak KWH | Variable LMP at time of delivery ¢ KWH |

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

| | | | |
|---|---|---|---|
| A. | 2023/2024 | $3.48 | kW/month |
| | 2024/2025 | $3.72 | kW/month |
| | 2025/2026 | $3.25 | kW/month, times the lowest of: |

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

*Continued on Sheet 20-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff COGEN/SPP I Continued
# (Cogeneration and/or Small Power Production--100 KW or Less)

**Monthly Credits or Payments for Energy and Capacity Deliveries Continued**

If T.O.D. energy meters are used,

| | | | |
|---|---|---|---|
| B. | 2023/2024 | $8.36 | kW/month |
| | 2024/2025 | $8.92 | kW/month |
| | 2025/2026 | $7.79 | kW/month, times the lowest of: |

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305 or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

**On-Peak and Off-Peak Periods**
The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

**Charges for Cancellation or Non Performance Contract**
If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

**Term of Contract**
Contracts under this tariff shall be made for a term not less than five (5) years. A Qualifying Facility can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff COGEN/SPP II
# (Cogeneration and/or Small Power Production--Over 100 KW)

**Availability of Service**
This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of over 100 KW. In addition, cogeneration facilities must have a net power production capacity at or below 20,000 KW, and small power production facilities must have a net power production capacity at or below 5,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

**Monthly Charges for Delivery from the Company to the Customer**
Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

**Additional Charges**
There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge
The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

| | Single Phase | Polyphase |
|---|---|---|
| Standard Measurement | $9.25 | $12.10 |
| T.O.D. Measurement | $9.85 | $12.40 |

*Continued on Sheet 21-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff COGEN/SPP II Continued
# (Cogeneration and/or Small Power Production-- Over 100 KW)

**Additional Charges Continued**

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

**Monthly Credits or Payments for Energy and Capacity Deliveries**

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

| | |
|---|---|
| Standard Meter – All KWH | Variable LMP at time of delivery ¢ KWH |
| T.O.D. Meter | |
| On-Peak KWH | Variable LMP at time of delivery ¢ KWH |
| Off-Peak KWH | Variable LMP at time of delivery ¢ KWH |

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

| | | | |
|---|---|---|---|
| A. | 2023/2024 | $3.48 | kW/month |
| | 2024/2025 | $3.72 | kW/month |
| | 2025/2026 | $3.25 | kW/month, times the lowest of: |

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

*Continued on Sheet 21-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff COGEN/SPP II Continued
# (Cogeneration and/or Small Power Production-- Over 100 KW)

**Monthly Credits or Payments for Energy and Capacity Deliveries Continued**

If T.O.D. energy meters are used,

| | | | |
|---|---|---|---|
| B. | 2023/2024 | $8.36 | kW/month |
| | 2024/2025 | $8.92 | kW/month |
| | 2025/2026 | $7.79 | kW/month, times the lowest of: |

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

**On-Peak and Off-Peak Periods**
The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

**Charges for Cancellation or Non Performance Contract**
If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/ SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

**Term of Contract**
Contracts under this tariff shall be made for a term not less than five (5) years. A Qualifying Facility can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

# Tariff C.S.-I.R.P.
# (Contract Service – Interruptible Power)

**Availability of Service**

Available for service to customers who contract for service under the Company's Industrial General Service (I.G.S.) tariff. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000 kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

**Conditions of Service**

The Company will offer eligible customers the option to receive interruptible power service. This interruptible service will be consistent with PJM's Load Management Resource Product – Capacity Performance Demand Response requirement, hereafter referred to as the "PJM Demand Response Program", subject to any limitations on the availability of that Program by PJM. To be eligible for the credit, customers must be able to provide interruptible load (not including behind the meter diesel generation) of at least one (1) MW at a single site and commit to a minimum four (4) year contract term. The contract shall provide that 90 days prior to each contract anniversary date, the customer shall re-nominate the amount of interruptible load for the upcoming contract year, except that the cumulative reductions over the life of the contract shall not exceed 20% of the original interruptible load nominated under the contract. If no re-nomination is received at least 90 days prior to the contract anniversary date, the prior year's interruptible load shall apply for the forthcoming contract year.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written addendum containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet average maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

The Company reserves the right to test and verify the customer's ability to curtail. Any such test or verification may require actual physical interruption or curtailment, to the extent such testing or interruption is required under PJM's Demand Response Program.

NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Except as otherwise provided in the written agreement, the Company's Terms and Conditions of Service shall apply to service under this tariff.

*Continued on Sheet 22-2*

# Tariff C.S.-I.R.P. Continued
# (Contract Service – Interruptible Power)

**Rate**
Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's Demand Response Program rules as capacity for the purpose of the Company's Fixed Resource Requirement (FRR) obligation.

| Tariff | Tariff Type | Tariff Code Description | Tariff Description |
|---|---|---|---|
| 321 | IR | CS-IRP SEC | IRP-IGS SECONDARY |
| 330 | IR | CS-IRP PR | IRP-IGS PRIMARY |
| 331 | IR | CS-IRP ST | IRP-IGS SUBTRANSMISSION |
| 332 | IR | CS-IRP TR | IRP-IGS TRANSMISSION |

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect the firm service rates otherwise available to the Customer.

**Adjustment Clauses**
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

| | |
|---|---|
| Kentucky Economic Development Surcharge | Sheet No. 27 |
| Demand-Side Management Adjustment Clause | Sheet No. 28 |
| System Sales Clause | Sheet No. 29 |
| Fuel Adjustment Clause | Sheet No. 30 |
| Purchase Power Adjustment | Sheet No. 31 |
| Environmental Surcharge | Sheet No. 32 |
| Decommissioning Rider | Sheet No. 33 |
| Distribution Reliability Rider | Sheet No. 34 |
| Securitization Financing Rider | Sheet No. 35 |
| Federal Tax Change Tariff | Sheet No. 36 |
| City's Franchise Fee | Sheet No. 37 |
| School Tax | Sheet No. 38 |

**Confidentiality**
All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR 5:001 Section 7 and the request is granted.

**Special Terms and Conditions**
Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

# Rider D.R.S.
# (Demand Response Service)

**Availability of Service**

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

**Conditions of Service**

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

8. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.**

*Continued on Sheet 23-2*

# Rider D.R.S. Continued
# (Demand Response Service)

**Interruptible Capacity Reservation**
The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

**The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.**

**Monthly Interruptible Demand Credit**
The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

**Interruption Event Compliance**
A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

**DRS Event Failure**
A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

| Number of Failures | Penalty Payment % |
|---|---|
| Failure 1 | 5% |
| Failure 2 | 10% |
| Failure 3 | 10% |
| Failure 4 | 15% |
| Failure 5 | 15% |
| Failure 6 | 20% |
| Failure 7 | 25% |
| Totals | 100% |

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

**Settlement**
The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

**Term**
A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff V.C.S.
# (Voluntary Curtailment Service)

This Rider provides the Customer with the opportunity to reduce their cost of electric service by curtailing usage during Voluntary Curtailment Events requested by the Company. Upon each event, the Customer shall have the option, but not the obligation, to curtail usage at their premises and be compensated by the Company as provided below.

**Availability of Service**

The initial term of this tariff is two (2) years beginning January 28, 2022. Eligible customers must have a curtailable usage of not less than 1,000 kW at the metering point for a single account for electric service, have accounts that are current, and maintain satisfactory credit criteria as defined under the Company's Terms and Conditions under Deposits, Section D. All provisions of the applicable standard tariff for electric service will apply except as modified herein. Customers participating in a third-party demand response program and customers receiving service under special contracts, including COGEN/SPP contracts, are not eligible to participate under this Rider. Customers in this program are also subject to curtailments due to system emergencies in the same manner as all other firm service customers.

**Monthly Charges and Credits**

Customer's net monthly bill for service provided under this Rider will be calculated in accordance with the Company's applicable rate schedule, with the exception that the Voluntary Curtailment Credit will be applied as a line item on the Customer's bill.

The Voluntary Curtailment Event Hours and the Voluntary Curtailment Price will be quoted to the Customer by no later than 5:00 p.m. ET of the day prior to the Event Day.

The Voluntary Curtailment Price will be based upon the Day-Ahead Market price of energy at the time of the Voluntary Curtailment Event, as determined in the Company's sole judgment, but not less than $100 per MWh. The AEPKY_RESID_AGG LMP shall be used to develop the Voluntary Curtailment Price.

**Conditions of Service**

1. The Company reserves the right to request a Voluntary Curtailment Event at any time at the Company's sole discretion. The Company will call no more than two (2) Voluntary Curtailment Events per day. The Events must be separated by at least one (1) non-event hour.
2. Customers must request enrollment in the program thirty (30) days before participating in a Voluntary Curtailment Event. A fully executed contract is required before a customer may participate in a Voluntary Curtailment Event.
3. The Company shall notify the Customer of a Voluntary Curtailment Event by e-mail, text or automated phone message. The Customer shall designate their representative(s) to receive said notifications.
4. No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.
5. The Customer shall not receive credit for any curtailment periods in which the Customer's usage is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions or any event other than the Customer's normal operating conditions.
6. The Customer's participation in any Company capacity-based demand response program takes priority over this program. No credit shall be given under this program for hours that a customer is responsible for curtailing under another program. An interval meter is required for service under this Rider. The incremental cost of any special metering, communications or control equipment required for service under this Rider beyond that normally provided shall be borne by the Customer.

*Continued on Sheet 24-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff V.C.S. Continued
# (Voluntary Curtailment Service)

**Curtailed Demand**
For each Voluntary Curtailment Event, Curtailed Demand shall be defined as the difference between the Customer's Average On-Peak Demand and the maximum sixty (60)-minute integrated demand in kW during the Voluntary Curtailment Event. The Curtailed Demand so computed will not be less than zero (0).

The Company shall determine the Customer's Average On-Peak Demand in kW specified in a contract or contract addendum for service under this Rider. The Customer's Average On-Peak Demand will be reviewed annually. Annual, seasonal or monthly Average On-Peak Demands may be established based upon Customer's historic usage patterns. For the purpose of determining the Average On-Peak Demand, the on-peak period is defined as 7:00 a.m.to 11:00 p.m. ET for all weekdays, Monday through Friday.

**Voluntary Curtailment Credit**
For each Voluntary Curtailment Event, the Event Credit shall be the product of the Curtailed Demand, the number of Voluntary Curtailment Event Hours and the Voluntary Curtailment Price.

The Voluntary Curtailment Credit will be the sum of the Event Credits for the calendar month.

The Voluntary Curtailment Credit will be applied to the Customer's bill within forty-five (45) days after the end of the month in which the Voluntary Curtailment Event occurred.

The Voluntary Curtailment Credit applied to the Customer's bill for service will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identity of this amount is preserved.

**Non-Compliance Provision**
There are no charges for non-compliance with a Voluntary Curtailment Event.

**Term**
Contracts under this Rider shall be made for an initial period of one (1) year and shall remain in effect thereafter until either party provides to the other at least thirty (30) days written notice of its intention to discontinue service under this Rider.

# Tariff E.D.R.
# (Economic Development Rider)

**Availability of Service**
To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S. and I.G.S. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

**Terms and Conditions**

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non- discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. The last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information must include:

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment,
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives or assistance associated with the new or expanded project, and
e. A statement that without the EDR discount, the customer would locate elsewhere or would choose not to expand within Kentucky Power's service territory.

*Continued on Sheet 25-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff E.D.R. Continued
# (Economic Development Rider)

**Terms and Conditions Continued**

(4) For new and existing customers, billing demands for which reductions will be applicable under this EDR shall be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another Company-served location or load transfers from another Company-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(5) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(6) Service under the EDR will be offered under the applicable Tariff L.G.S. or I.G.S. schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4) six (6), eight (8), or ten (10) years only.

(7) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(8) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company, and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9.

(9) The L.G.S., and I.G.S. tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

*Continued on Sheet 25-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff E.D.R. Continued
# (Economic Development Rider)

**Determination of Monthly Qualifying Incremental Billing Demand**
For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., I.G.S., for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

**Determination of Incremental Billing Demand Discount**
Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The qualifying incremental billing demand charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of the Customer's choosing at the time of the contract filing. A sample illustration of an (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S. or I.G.S., demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S. or I.G.S., demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S. or I.G.S., demand charge;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount and a maximum annual IBDD of 40% in one year. Similarly, a six (6) year contract will have three (3) years of discount and a maximum annual IBDD of 30% in one year.

*Continued on Sheet 25-4*

# Tariff E.D.R. Continued
# (Economic Development Rider)

**Determination of Supplemental Billing Demand Discount**

At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The order in which the SBDD is applied will follow the same order selected by the Customer for the IBDD contract. A sample illustration of the SBDD for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced an additional 4.5% for an increase of at least 50 jobs or 2.0% for an increase of at least 25 jobs;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with a maximum SBDD of either 4.5% or 2.0% as appropriate during one year of the contract.

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months as selected by the Customer in 12-month increments at the time of the contract.

**Terms of Contract**

A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S. or I.G.S., shall be executed by the Customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate.

**Special Terms and Conditions**

Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

# Tariff R.E.A.
# (Residential Energy Assistance)

Proceeds of the charge and ~~matching~~ a Company contribution~~s~~ (that equals two times the amount collected from the per meter charge) will be used to provide financial assistance to eligible residential customers' ~~fix~~ electric bills during peak hea~~r~~ting months (January through April).

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2

**Rate**
$0.40 per month per residential account.

**Programs**
Participation in the programs below will be determined by the residential customer's local community action agency in accordance with guidelines approved by the Commission and the availability of funds. Customer participation is limited to one program each calendar year.

**Home Energy Assistance in Reduced Temperatures (HEART)**
Participating low-income residential customers, whose primary source of heat is electric, are eligible to receive an electric bill credit of $115.00 a month for bills rendered in January through April.

Participating low-income residential customers, whose primary source of heat is non-electric, are eligible to receive an electric bill credit of $58.00 a month for bills rendered in January through April.

**Temporary Heating Assistance in Winter (THAW)**
Participating residential customers, who are experiencing temporary economic hardships, are eligible to receive electric bill credits totaling no more than $175.00 for bills rendered in January through April in any single calendar year.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff K.E.D.S.
# (Kentucky Economic Development Surcharge)

Proceeds of the surcharge and matching Company contributions will be used to fund economic development programs and activities as determined by the Company within the 20 counties comprising Kentucky Power's certified territory.

**Applicable**
To Tariffs G.S, S.G.S. – T.O.D., M.G.S. – T.O.D., L.G.S., L.G.S. – T.O.D., I.G.S., C.S. – I.R.P., M.W.

**Rate**
$1.00 per month per commercial account.

# Tariff D.S.M.C.
# (Demand-Side Management Adjustment Clause)

**Applicable**

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., and M.W.,

**Rate**

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{(c) Adjustment Factor} = \frac{DSM}{S(c)}$$

Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The efficiency incentive, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the maximizing incentive which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      i. the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      ii. the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      iii. the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2023.

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

*Continued on Sheet 28-2*

# Tariff D.S.M.C. Continued
# (Demand-Side Management Adjustment Clause)

**Rate Continued**

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

| | Customer Sector | | |
|---|---|---|---|
| | Residential | Commercial | Industrial* |
| DSM(c) | $479,489 | $181,893 | 0 |
| S(c) | 1,943,627,965 | 1,448,924,338 | 0 |
| Adjustment Factor | $0.000247 | $0.000126 | 0 |

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

**Program Descriptions**
The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

*Continued on Sheet 28-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff D.S.M.C. Continued
# (Demand-Side Management Adjustment Clause)

## Program: TEE – Targeted Energy Efficiency

**Availability of Service**

Available on a voluntary basis to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh per month from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by the local community action agency.

**Program Description**

The Kentucky Power Targeted Energy Efficiency Program (TEE) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by the local community action agency. This program provides energy saving improvements to an existing home. Program services include residential energy audits, the installation of home weatherization/energy conservation items and customer education on home energy efficiency. The home weatherization/energy conservation measures may include, but not limited to:

- High efficiency lighting
- Domestic hot water pipe insulation
- Water heater insulation wrap (electric DHW only)
- Low flow showerhead
- Low flow faucet aerator
- Air and duct sealing (electric heat only)
- Insulation (electric heat only)
- Efficient windows and doors
- Air source heat pump

**Rate**

No rate applies for this program.

**Equipment**

The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment as provided by this program.

# Tariff S.S.C.
# (System Sales Clause)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L. and S.L.

**Rate**

1. When the annual net revenues from system sales are above or below the annual base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   Annual System Sales Adjustment Factor (A) = (1.0 [Ta –Tb+U/a])/Sa

   In the above formula "T" is Kentucky Power Company's (KPCo) annual net revenues from system sales in the current annual (a), base (b) periods, and "S" is the KWH sales in the current annual (a) period, all defined below. "U/a" represents any under-or-over recovery from the prior period.

   The applicable rate for service rendered on and after September 28, 2021, calculated in accordance with the above formula, is $(.00066) per kWh.

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

3. The base annual net revenues from system sales are: $ 1,935,350

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon actual annual revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The annual System Sales Clause shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle. The Company shall update the Annual System Sales Adjustment Factor for the period ending June 30, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff F.A.C.
# (Fuel Adjustment Clause)

**Applicable**
To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, R.S.D., G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

**Rate**

1. The fuel clause shall provide for periodic adjustment per kWh of sales equal to the difference between the fuel costs per kWh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

   Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the Company to substitute for its own higher cost of energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

   e. The fuel-related costs charged to the Company by PJM Interconnection LLC those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

   f. All fuel costs shall be based on weighted average inventory costing.

   g. All Commission approved financial power hedging program-related contract settlements, and related contract costs.

*Continued on Sheet 30-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff F.A.C. Continued
# (Fuel Adjustment Clause)

**Rate Continued**

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

5. Sales (S) shall be all kWh's sold, excluding intersystem sales. If, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to: (i) generation, plus (ii) purchases, plus (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power. Any changes in the contracts or other documents, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by 807 KAR 5:056 (Fuel Adjustment Clause).

8. The monthly fuel adjustment shall be filed with the Commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

9. Copies of all documents required to be filed with the Commission under 807 KAR 5:056 shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

10. At six (6) month intervals, the Commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments. The Commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the Commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practice.

11. Every two (2) years following the initial effective date of each utility's fuel clause, the Commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1 (2) of 807 KAR 5:056.

12. The Commission may conduct a public hearing if the Commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest.

13. Resulting cost per kilowatt-hour in February 2020 to be used as the base cost in Standard Fuel Adjustment Clause is:

| | | | | | |
|---|---|---|---|---|---|
| Fuel | February 2020 | ÷ | $12,810,858 | = | $0.02612/kWh |
| Sales | February 2020 | | 490,482,730 | | |

This, as used in the Fuel Adjustment Clause, is 2.612¢ per kilowatt-hour.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.P.A.
# (Purchase Power Adjustment)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., M.W., O.L. and S.L.

**Rate**
The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

   PPANC = N+CSIRP+RKP+RP-BPP

   Where:

   BPP = The annual amount of purchase power costs included in base rates, $6,554,678.

   a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II above or below the $1,269,331 included in BPP. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
   b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., Tariff V.C.S. and special contracts for interruptible service above or below the $1,165,983 included in BPP.
   c. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
      1. Rockport deferral amount to be recovered;
      2. Rockport offset estimate and true-up.
      3. Final (over)/under recovery associated with tariff CC following its expiration
   d. RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $4,119,364 included in BPP.

*Continued on Sheet 31-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.P.A. Continued
# (Purchase Power Adjustment)

**Rates**

| Tariff Class | $/kWh | $/kW |
|---|---|---|
| R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D. | $0.00353 | -- |
| S.G.S.-T.O.D. | $0.00288 | -- |
| M.G.S.-T.O.D. | $0.00288 | -- |
| G.S. | $0.00288 | -- |
| L.G.S., L.G.S.-T.O.D. | $0.00014 | $0.82 |
| L.G.S.-L.M.-T.O.D. | $0.00265 | -- |
| I.G.S. and C.S.-I.R.P. | $0.00014 | $1.04 |
| M.W. | $0.00199 | -- |
| O.L. | $0.00051 | -- |
| S.L. | $0.00051 | -- |

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

*Continued on Sheet 31-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff P.P.A. Continued
# (Purchase Power Adjustment)

**Rates Continued**

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.
2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.
3. "BE $_{Class}$" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD $_{Class}$" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP $_{Class}$" is the coincident peak demand for each tariff class estimated as follows:

| Tariff Class | $BE_{Class}$ | CP/kWh Ratio | $CP_{Class}$ |
|---|---|---|---|
| R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D. | | 0.022970% | |
| S.G.S.-T.O.D. | | 0.018187% | |
| M.G.S.-T.O.D. | | 0.018187% | |
| G.S. | | 0.018187% | |
| L.G.S., L.G.S.-T.O.D. | | 0.016146% | |
| L.G.S.-L.M.-T.O.D. | | 0.016146% | |
| I.G.S. and C.S.-I.R.P. | | 0.011832% | |
| M.W. | | 0.012350% | |
| O.L. | | 0.005294% | |
| S.L. | | 0.005375% | |

6. "BE $_{Total}$" is the sum of the BE Class for all tariff classes.
7. "CP $_{Total}$" is the sum of the CP Class for all tariff classes.
8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.40% and the KPSC Maintenance Fee of 0.1493% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues.
9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

# Tariff E.S.
# (Environmental Surcharge)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

**Rate**
The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 2 below and in the current period as provided in Paragraph 3 below.

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment, and Distribution Reliability Rider.

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Distribution Reliability Rider.

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

| | | | |
|---|---|---|---|
| Where: | E(m) | = | CRR-BRR |
| | CRR | = | Current Period Revenue Requirement for the Expense Month. |
| | BRR | = | Base Period Revenue Requirement. |

2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

| Billing Month | | Base Net Environmental Costs |
|---|---|---|
| January | $ | 3,022,418 |
| February | | 2,558,332 |
| March | | 2,621,611 |
| April | | 2,519,828 |
| May | | 2,514,284 |
| June | | 2,644,974 |
| July | | 2,594,563 |
| August | | 2,741,097 |
| September | | 2,508,995 |
| October | | 2,376,639 |
| November | | 2,423,992 |
| December | $ | 2,597,739 |
| | $ | 31,124,472 |

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020.

*Continued on Sheet 32-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff E.S. Continued
# (Environmental Surcharge)

3. Current Period Revenue Requirement, CRR
   $CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} - AS]$

   Where:

   | | | |
   |---|---|---|
   | $RB_{KP(c)}$ | = | Environmental Compliance Rate Base for Mitchell. |
   | $ROR_{KP(c)}$ | = | Annual Rate of Return on Mitchell Environmental Compliance Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return. |
   | $OE_{KP(c)}$ | = | Monthly Pollution Control Operating Expenses for Mitchell. |
   | AS | = | Net proceeds from the sale of Title IV and CSAPR SO 2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. |

   “KP(C)” identifies components from Mitchell Units – Current Period.

   The Environmental Compliance Rate Base for Kentucky Power reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service. The Operating Expenses for Kentucky Power reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan.

   The Rate of Return for Kentucky Power is 9.65~~90~~% rate of return on equity as authorized by the Commission in its Order Dated XXXX XX, 20XX, Case No. 2023-00159.

   Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

   The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

*Continued on Sheet 32-3*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff E.S. Continued
# (Environmental Surcharge)

4. Revenue Allocation

Residential Allocation RA(m) = KY Residential Retail Revenue RR(b) / KY Retail Revenue R(b)

All Other Allocation OA(m) = KY All Other Classes Retail Revenue OR(b) / KY Retail Revenue R(b)

Where:

(m) = the expense month.
(b) = the most recent calendar year revenues

5. Environmental Surcharge Factor

Residential Monthly Environmental Surcharge Factor = Net KY Retail E(m) * RA(m) / KY RR(m)

All Other Monthly Environmental Surcharge Factor = Net KY Retail E(m) * AO(m) / KY OR(m)- KY OF(m)

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

RR(m) = Average Kentucky Residential Retail Revenues for the Preceding Twelve Month Period

OR(m) = Average Kentucky All Other Classes Retail Revenues for the Preceding Twelve Month Period

OF(m) = Average Kentucky All Other Classes Fuel Revenues for the Preceding Twelve Month Period.

*Continued on Sheet 32-4*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Tariff E.S. Continued
# (Environmental Surcharge)

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

   Total Company:
   - return on Title IV and CSAPR $SO_2$ allowance inventory
   - over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
   - costs associated with any Commission's consultant approved by the Commission
   - costs associated with the consumption of Title IV and CSAPR $SO_2$ allowances
   - costs associated with the consumption of $NO_x$ allowances
   - return on $NO_x$ allowance inventory
   - costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
   - costs associated with consumables used in conjunction with approved environmental projects.
   - return on inventories of consumables used in conjunction with approved environmental projects.
   - return on environmental compliance rate base including construction work in progress.
   - Monthly expense to amortize the $1,446,998.35 regulatory asset for prudently incurred ELG (Effluent Limitation Guidelines) project costs over a two-year period to begin with July 2022 billing and conclude with June 2024 billing.

   The Company's share of costs associated with the following environmental equipment at the Mitchell Plant:
   - Mitchell Unit Nos 1 and 2 Water Injection, Low $NO_x$ burners, Low $NO_x$ burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and $SO_3$ Mitigation
   - Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
   - Air Emission Fees
   - Precipitator Modifications and Upgrades
   - Coal Combustion Waste Landfill
   - Bottom Ash and Fly Ash Handling
   - Mercury Monitoring (MATS)
   - Dry Fly Ash Handling Conversion
   - Wastewater Ponds (for the Mitchell CCR compliance project) with depreciation expense calculated using a 20 percent depreciation rate approved by the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Decommissioning Rider
# (D.R.)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

**Rate**

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) as set in the Company's most recent Rate Case carrying cost over a 25 year period beginning with the date rates became effective in Case No. 2014-00396. The term "Retirement Costs" are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

   The applicable rates for service rendered on and after September 28, 2022 to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$12{,}203{,}475}{\$260{,}106{,}760} = 4.6917\%$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$14{,}511{,}306}{\$183{,}145{,}514} = 7.9234\%$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve month period, ending June 30 according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

   Where:

   (y) = the expense year;
   (b) = Most recent available twelve month period ended June 30.

*Continued on Sheet 33-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Decommissioning Rider Continued

3. The Residential D.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential D.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

| | | |
|---|---|---|
| Net Annual Residential Allocation NRA(b) | = | Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment; |
| Residential Retail Revenue RR(b) | = | Annual Retail Revenue for all KY residential classes for the year (b). |

4. The All Other Classes D.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes D.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

| | | |
|---|---|---|
| Net Annual All Other Allocation NOA(y) | = | Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment; |
| All Other Classes Non-Fuel Retail Revenue ONR(b) | = | Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b). |

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment, and Distribution Reliability Rider.

   The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Distribution Reliability Rider.

6. The annual Decommissioning Rider adjustments shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Distribution Reliability Rider
# (D.R.R.)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S. Secondary and Primary, S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S. Secondary and Primary, L.G.S.-T.O.D. Secondary and Primary, I.G.S. Secondary and Primary, C.S. – I.R.P. Secondary and Primary, and M.W.

**Rate**
The Distribution Reliability Rider will apply to all customers served at secondary and primary voltages excluding customers receiving service under Tariffs O.L. and S.L. The Annual Distribution Reliability Net Costs to be recovered through this rider will be capped at 1% of the prior year's total retail revenue. The Annual Distribution Reliability Net Costs to be recovered through this rider will be calculated on a per bill basis using the following formula:

1. Annual Distribution Reliability Net Costs (ADRNC)

   ADRNC = ERW + ATL + DACRR + ANDSS + ARSHR + Rollover

   Where:

   a. ERW = targeted widening of primary distribution circuits.

   b. ATL = the cost of constructing primary lines to tie two circuits together to permit electrical load to be transferred.

   c. DACRR = the costs of installing automation equipment to allow for the isolation of a fault and reconfiguration of the circuit to close other devices to re-energize the non-impacted areas of original circuit impacted by the initial fault and the recloser devices upgrade from three-phase to single-phase to allow for future DACR implementation, closure via electronics, event recordings and power quality investigations, and more precise coordination with other devices.

   d. ANDSS = the costs of new distribution substations in remote areas with associated transmission lines in and out to reduce the number of radial distribution circuits and reduce outage times.

   e. ARSHR = the costs of targeted facilities projects to renew and improve cable, conductor, hardware, and equipment to reduce feeder-level outages.

   f. Rollover = Unspent ADRNC amounts from prior years.

   g ~~f~~. Subparts a through e include the capital expenditure and operations and maintenance to support that capital to enhance customer reliability.

2. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2021-00159 dated ________ as filed and approved by the Commission, Kentucky Power Company is to recover from its retail customers the costs associated with the Distribution Reliability Work Plan including vegetation management and other targeted investments to maintain and improve reliability.

3. The allocation of the ADRNC between residential and all other customers shall be based upon their respective contribution to total non-fuel retail revenues for the most recent twelve-month period, ending December 31 according to the following formula:

*Continued on Sheet 34-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

## Distribution Reliability Rider Continued
## (D.R.R.)

~~3. The allocation of the ADRNC between residential and all other customers shall be based upon their respective contribution to total non-fuel retail revenues for the most recent twelve-month period, ending December 31 according to the following formula:~~

$$\text{Residential Allocation(y)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Classes Allocation(y)} = \frac{\text{KY All Other Classes Non-Fuel Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

| | | |
|---|---|---|
| (y) | = | the expense year; |
| (b) | = | most recent available twelve month period ended December 31; |
| RR | = | $XXX; |
| OR | = | $XXX; and |
| R | = | $XXX. |

4. The rate will be calculated according to the following formula:

$$\text{Residential Factor} = \frac{\text{Residential Allocation x ADRNC}}{\text{Number of Residential Bills}}$$

$$\text{All Other Classes Factor} = \frac{\text{All Other Classes Allocation x ADRNC}}{\text{Number of All Other Classes Bills}}$$

5. The applicable rates for service rendered on and after _________, calculated in accordance with the above, is:

$$\text{Residential Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

$$\text{All Other Classes Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

All Other Classes excludes Tariffs O.L. and S.L. and all customers receiving service at subtransmission and transmission voltage levels.

6. Beginning in 2024, the Company will file its annual DRR Work Plan for review, and for approval if material modifications are proposed, by the Commission by September 1 of the year preceding the start of the proposed DRR Work Plan. The September 1 filing also will include a progress update on current-year DRR projects.

7. The annual Distribution Reliability Rider adjustments shall be filed with the Commission no later than February 15th of each year before it is scheduled to go into effect Cycle 1 of April billing, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission. The filing also will include a

summary of DRR projects completed in the previous year (beginning with the February 15, 2025 filing) and a progress update on current-year projects.
~~6.~~

~~7.~~8. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

# Securitization Financing Rider
# (S.F.R.)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

**Rate**

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to recover from retail ratepayers the costs approved for securitization by the Commission.

   This rider is designed to recover from customers the amounts necessary to service, repay and administer customer-backed bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in Case No. 202#-#####.

   This rider shall remain in effect until the complete repayment and retirement of any customer-backed bonds, or refunding bonds, associated with the approved securitized costs. This schedule is irrevocable and nonbypassable for the full term during which it applies.

   The applicable rates for service rendered on and after XXXXXXXXX ##, 202# to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve-month period ending December 31 or June 30, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

   Where:

   (y) = the expense year;
   (b) = Most recent available twelve month period ended December 31 or June 30.

*Continued on Sheet 35-2*

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Securitization Financing Rider Continued
# (S.F.R.)

3. The Residential S.F.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential S.F.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

| | | |
|---|---|---|
| Net Annual Residential Allocation NRA(y) | = | Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment; |
| Residential Retail Revenue RR(b) | = | Annual Retail Revenue for all KY residential classes for the year (b). |

4. The All Other Classes S.F.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes S.F.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

| | | |
|---|---|---|
| Net Annual All Other Allocation NOA(y) | = | Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment; |
| All Other Classes Non-Fuel Retail Revenue ONR(b) | = | Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b). |

5. The Revenues to which the residential Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment and Distribution Reliability Rider.

   The Revenues to which the all other customer Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power Adjustment and Distribution Reliability Rider.

6. The initial Securitization Financing Rider rates shall be file on the day following the pricing of the bonds and shall become effective the first billing cycle following the closing of the bonds. All subsequent Rider rate adjustments shall be semi-annual (every six months).

   The semi-annual Securitization Financing Rider adjustments shall be filed with the Commission no later than February 15 and August 15th of each year before it is scheduled to go into effect on Cycle 1 of the April and October billing cycles, respectively, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

   Interim Securitization Financing Rider adjustments may be filed with the Commission outside of the standard semi-annual timeframe in order to correct for over- or under-collection to be submitted no later than 10 days before the rate is to be effective.

   Quarterly true-ups will begin 12 months prior to the scheduled final payment date for the latest maturing tranche of securitized bonds of a particular series.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# Federal Tax Change Tariff
# (F.T.C.)

**Applicable**
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

**Rate**

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January XX, 2024.

2. The Company shall amortize the calendar year retail Generation and Distribution related Protected Excess ADIT of $1,678,164 to support the rate credits provided to customers through this tariff.

3. ~~Beginning with the October 2024 Federal Tax Change Tariff adjustment filing, the actual Corporate Alternative Minimum Tax (CAMT) expense and credits for the prior calendar/tax year shall be included in the Annual Revenue Requirement based on the Company's actual 2023 federal income tax return. This methodology will continue on a year to year basis.~~Subject to Commission approval of the Company's application for a financing order authorizing the Company to securitize the Rockport Deferral Regulatory Asset, Tariff P.P.A. Under-Recovery Regulatory Asset, and Storm Expense Deferral Regulatory Assets identified in the Company's Application in 2023-00159 (collectively, the "Non-Decommissioning Rider Regulatory Assets"), and subject to the Company's issuance of securitized bonds that include the Non-Decommissioning Rider Regulatory Assets, the Company shall provide customers with the ADIT benefit related to Non-Decommissioning Rider Regulatory Assets approved for securitization through this tariff, at its Commission-approved WACC. The ADIT benefit described in this paragraph will be annually trued-up to address over/(under) recovery pursuant to the procedure described in paragraph 7 of this tariff.
~~3.~~

~~4. For purposes of computing over or under-recovery under this tariff, the Company shall include the actual CAMT expense and the actual CAMT credits at the time that the credits can be used.~~

~~5.~~4. The Company shall include a final reconciliation of the retail Generation and Distribution related Unprotected Excess ADIT as part of the over or under-recovery computation in the October 2024 Federal Tax Change Tariff adjustment filing.

~~6.~~5. The applicable rates on a kWh basis are as follows:

| Residential ($/kWh) | All Other ($/kWh) |
|---|---|
| $(0.000662~~53~~) | $(0.000443~~37~~) |

~~7.~~6. The allocation of the Annual Revenue Requirement (ARR) which consists of the retail Generation and Distribution related Protected Excess ADIT, the ~~actual CAMT expenses and credits~~ADIT benefits related to the securitized Non-Decommissioning Rider Regulatory Assets and any over or under-recovery based upon actual information for prior periods between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{AC(y)} \times \frac{\text{KY Residential Retail Revenue RR}}{\text{KY Retail Revenue R}}$$

$$\text{All Other Allocation OA(y)} = \text{AC(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR}}{\text{KY Retail Revenue R}}$$

Where:
(y) = the credit year;

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

| | | |
|---|---|---|
| RR | = | $301,523,011; |
| OR | = | $392,479,515; and |
| R | = | $694,002,526. |

~~8.~~7. The annual Federal Tax Change Tariff adjustments shall be filed with the Commission no later than October 15th of each year before it is scheduled to go into effect on Cycle 1 of the December billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

~~9.~~8. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

# Tariff C.F.F.
# (City's Franchise Fee)

**Availability of Service**

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town for the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# U.G.R.T.
# (Utility Gross Receipts Tax)
# (School Tax)

**Applicable**
To all Tariff Schedules.

**Rate**
This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

# K.S.T.
# (Kentucky Sales Tax)

**Applicable**
To all Tariff Schedules.

**Rate**
This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(7). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

Sales of electricity under Tariff R.S. are exempt from sales tax only if the service is to the customer's place of domicile as defined by KRS 139.470(7)(b). Kentucky Power may retroactively charge a customer, under the parameters of KRS 278.225, for all applicable sales tax the Department of Revenue determines is due for service that is not exempt. It is the customer's responsibility to file all necessary documentation, including Form 51A380 (1-23), when notified by the Company, establishing the customer's place of domicile. In such a case, any exemption will become effective with the customer's first full billing cycle after the customer's delivery of a properly executed Form 51A380 (1-23).

DATE OF ISSUE: ~~June 29, 2023~~XXXX XX, XXXX
DATE EFFECTIVE: January 15, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

**DATA REQUEST**

**KPSC PHDR_7** Provide three actual Tariff Residential Service customer bills reflecting a representative low, average, and high usage bill for the month of October 2023 with all personal information redacted showing the current charges and riders.

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_7_Attachment1 for the requested information. The Company utilized and has presented November 2023 bills for each of the representative customers for two reasons. First, new rates for the System Sales Clause, Decommissioning Rider, and Purchase Power Adjustment went into effect with November 2023 billing.[1] Second, Settlement Agreement Exhibit 2 also utilizes November rates to calculate bill impacts.

Nonetheless, cell B3 can be changed to “October” by typing the word “October” in that cell to get the surcharge factors for October 2023 billing.

Witness: Lerah M. Kahn

[1] September 28, 2023 was the beginning service date for November 2023 billing. Kentucky Power implemented interim rates for Tariff Purchase Power Adjustment, subject to change pending the Commission’s final order in Case No. 2023-00318, consistent with its notice to do so filed September 29, 2023 in that case. Those interim rates went into effect for services rendered on and after September 29, 2023.

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_8** | Refer to Item 7. For the same three customer bills, provide what the bill be if the Commission granted the Kentucky Power settlement as filed, including the securitization financing rider assuming a 5 percent interest rate, inclusive of all other financing costs. |

**RESPONSE**

Please see the Company's response to KPSC PHDR-7.

Witness: Lerah M. Kahn

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

**KPSC PHDR_9** Refer to Kentucky Power's Response to Commission Staff's First Request for Information (Staff's First Request), Item 33, Confidential Attachment 1. Explain how salaries and wages are allocated from AEP to Kentucky Power. Include in the response the calculation for each allocation factor shown in this exhibit.

**RESPONSE**

AEP employees report actual time worked. There are no pre-approved percentages used to allocate time. The "KPCo % Share" percentages reported in column J of KPCO_R_KPSC_1_33_ConfidentialAttachment1 for Kentucky Power Officers that are employees of AEP represent composite amounts that are the result of AEP's system-enabled and work order-driven time reporting and labor costing procedures.

Please see sections 03-03-01 through 03-03-03 of the Company's Cost Allocation Manual, as provided as Exhibit A to Section II of the Company's Application, for a description of AEP time reporting and labor costing procedures. AEP charges allocated to Kentucky Power Company, including charges for salaries and wages, relate to work orders that have benefiting locations that include Kentucky Power Company. Total costs are allocated amongst the applicable benefiting locations based upon the attribution basis for the work order. The Company has not performed the complex time-consuming analysis to manually reperform the system-driven calculations related to numerous work orders used from 2019 through March 2023, each with an individually assigned benefiting location and attribution basis, which resulted in the composite percentages reported in column J of KPCO_R_KPSC_1_33_ConfidentialAttachment1 for Kentucky Power Officers that are employees of AEP. Instead, please reference the list of FERC approved attribution bases, or allocation factors, along with a description of the numerator and the denominator applicable to each calculation, in the Cost Allocation Manual Appendix at Section 99-00-04.

Witness: Heather M. Whitney

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_10** | Provide the capital plan for Kentucky Power for the years 2024 through 2030. Include in the response the forecasted projects proposed to be included in the Distribution Reliability Rider (DRR) for each of the year. |

**RESPONSE**

The Company's forward-looking capital plan is being presented for the years 2024-2030. The DRR Capital Work plan has only been developed for five years from 2024-2028.

Please see KPCO_R_KPSC_PHDR_10_Attachment1 for the Kentucky Power Capital Work Plan (for the years 2024-2030). The attachment also includes a summary of the DRR Work Plan costs for the years 2024-2028.

Please see KPCO_R_KPSC_PHDR_10_Attachment2 for the Kentucky Power Work Plan for DRR Capital Projects and associated capital costs.

Witness: Everett G. Phillips

Witness: Brian K. West

**Kentucky Power**
**Forecasted Capital Work Plan**
**2024-2030**

| Sum of Forecast $ | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|
| **10 Service Restoration** | **6,198,337** | **14,743,448** | **14,672,620** | **14,413,535** | **14,387,182** | **14,744,091** | **14,933,197** |
| 000001818 KY/Svc Restoration NonMjr Evt | 3,371,668 | 10,090,048 | 10,161,480 | 9,815,767 | 9,730,531 | 10,002,917 | 10,134,052 |
| 000002241 KP-Damage Claims-Reimburse | 192,099 | 213,464 | 212,753 | 218,164 | 221,149 | 225,503 | 230,379 |
| 000007599 KP-Failed Equip No Outage | 2,634,570 | 4,439,937 | 4,298,387 | 4,379,604 | 4,435,502 | 4,515,671 | 4,568,765 |
| **20 Externally Requested Work** | **10,567,191** | **11,992,604** | **10,908,332** | **11,115,186** | **11,272,968** | **11,254,642** | **11,408,479** |
| 000007558 KP-PQ-QOS Mitigation | 28,235 | 31,489 | 30,659 | 31,159 | 31,504 | 32,018 | 32,348 |
| 000007615 KP-Cust Req Relocate | 220,687 | 238,886 | 235,603 | 240,549 | 244,418 | 250,062 | 254,033 |
| 000008206 KP PPR Eng Support | 2,657 | 2,695 | 2,764 | 2,837 | 2,905 | 3,072 | 3,152 |
| EDN011333 Customer Meter/Kp | 763,152 | 909,884 | 868,106 | 884,264 | 894,335 | 903,468 | 912,950 |
| EDN012370 Ds/Kp/Public Relocation | 802,307 | 814,416 | 827,966 | 855,801 | 880,493 | 929,853 | 954,356 |
| EDN014651 Ds/Kp/Cs-New Customers | 3,262,063 | 3,770,717 | 3,217,139 | 3,259,643 | 3,293,976 | 3,205,061 | 3,237,421 |
| EDN014658 Ds/Kp/Cs-Upgrades | 247,229 | 258,491 | 259,755 | 266,052 | 271,495 | 285,132 | 290,086 |
| EDN014687 Ds-Kp-Ai Aepc Make Ready | -17,904 | -17,904 | -17,904 | -17,904 | -17,904 | -17,904 | -17,904 |
| EDN014694 Ds-Kp-Ai Other Make Ready | 593,917 | 702,895 | 673,428 | 688,457 | 698,505 | 711,501 | 721,085 |
| EDN100033 Ds/Kp/C&I New | 1,867,261 | 2,046,629 | 1,681,221 | 1,712,930 | 1,737,656 | 1,674,423 | 1,699,170 |
| EDN100044 Ds/Kp/C&I Upgrades | 94,589 | 111,165 | 106,541 | 108,085 | 108,438 | 109,174 | 109,983 |
| EON011326 Line Transformer/Kp | 2,702,997 | 3,123,242 | 3,023,054 | 3,083,313 | 3,127,146 | 3,168,783 | 3,211,799 |
| **30 Service Reliability & Mitigation** | **14,528,766** | **17,009,567** | **16,756,442** | **17,199,683** | **15,880,912** | **15,460,607** | **15,487,367** |
| 000001745 KP Reliability Improvements | | 3,064,134 | 2,928,622 | 3,327,726 | 3,305,536 | 2,873,451 | 2,843,121 |
| 000004737 KPSectionalizing Program | 180,784 | 196,228 | 191,937 | 193,918 | 195,206 | 196,805 | 198,021 |
| 000007818 KP/Small Local Asset Improv | 2,836,529 | 3,024,961 | 2,973,575 | 2,998,854 | 3,015,597 | 3,037,979 | 3,053,770 |
| 000008169 KP Asset Imp Eng Support | 810,159 | 830,516 | 852,009 | 874,655 | 893,518 | 938,460 | 959,506 |
| 000008184 KP Asset Programs Eng Support | 127,174 | 129,667 | 133,047 | 136,611 | 139,898 | 147,073 | 150,874 |
| 000016528 KYCutout-Arrester | 368,745 | 387,660 | 384,070 | 388,887 | 392,621 | 398,052 | 401,831 |
| EDN014680 Ds-Kp-Ai Pole Replacement | 1,439,361 | 1,499,309 | 1,484,632 | 1,493,282 | 1,498,619 | 1,505,155 | 1,511,094 |
| EDN014720 Ds-Kp-Ai Recloser Replacement | 960,938 | 1,105,663 | 1,067,263 | 1,087,614 | 1,101,371 | 1,121,475 | 1,134,338 |
| EDN015042 Ds-Kp-Small Wire Repl Ovhd | 590,399 | | | | | | |
| EDN100577 Ds-Kp-Ai Ckt Inspections | 510,674 | 544,224 | 539,858 | 546,479 | 550,157 | 555,122 | 560,636 |
| KY5YCYCLE KY D 2017-00179 | 2,703,999 | 2,727,205 | 2,701,430 | 2,651,655 | 1,288,388 | 1,187,034 | 1,174,176 |
| TREEREL21 ROW Capital Widening & Removal | 4 | -14,000,000 | 3,500,000 | 3,500,000 | 3,500,000 | 3,500,000 | 3,500,000 |
| TREEREL23 ROW Capital Widening & Removal | 4,000,000 | 17,500,000 | | | | | |
| **40 Asset Improvement & Modernization** | **13,181,549** | **14,203,847** | **17,443,804** | **21,862,494** | **20,930,646** | **8,288,181** | **12,779,534** |
| 000012320 KY Cpp Capacity Pot | 6,946,340 | 1,748,618 | 1,732,130 | 1,697,232 | 1,759,831 | 1,322,507 | 1,279,015 |
| 000021168 KY Capacity Capital Forecast | 4,187,580 | 4,292,270 | 4,399,576 | 4,509,566 | 4,622,305 | 4,737,862 | 4,856,309 |
| SMRTCRC Smart Circuit Budget Only | 0 | 8,162,959 | 11,312,098 | 15,655,696 | 14,548,510 | 2,227,812 | 6,644,210 |
| TP1403006 T Funded D Work | 1,440,000 | | | | | | |
| TP1930505 Orinoco T Funded D (Dist Line) | 607,629 | | | | | | |
| **90 Overheads/Allowances** | **6,901,096** | **8,348,005** | **8,572,103** | **8,808,159** | **9,037,528** | **9,282,771** | **9,564,645** |
| EDN103175 Ds Kp Anda | 6,795,161 | 8,250,724 | 8,474,729 | 8,709,034 | 8,937,438 | 9,181,222 | 9,461,474 |
| KYCAPTOOL KY Purch. Cap Tools | 19,255 | 4,654 | 4,413 | 4,493 | 4,538 | 4,579 | 4,621 |

**Kentucky Power**
**Forecasted Capital Work Plan**
**2024-2030**

| Sum of Forecast $ | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|
| **(blank)** | **42,328** | **45,301** | **45,468** | **46,302** | **46,762** | **47,470** | **48,260** |
| 000014717 KY/DOP/Copper Theft | 42,542 | 45,301 | 45,468 | 46,302 | 46,762 | 47,470 | 48,260 |
| TA1692804 KPCo Major Eq/Spares Chkbk-Dis | 2,131,128 | 2,156,327 | 2,168,029 | 2,153,903 | 2,152,236 | 2,179,584 | 2,173,398 |
| TA2175005 KY D Station/Line Checkbook | -2,131,342 | -2,156,327 | -2,168,029 | -2,153,903 | -2,152,236 | -2,179,584 | -2,173,398 |
| **Work Plan Total** | **51,332,586** | **66,250,146** | **68,305,808** | **73,350,728** | **71,460,446** | **58,980,793** | **64,122,932** |
| **DRR Total** | **19,000,000** | **35,288,300** | **32,881,000** | **38,733,000** | **40,006,500** | | |
| **Grand Total** | **70,332,586** | **101,538,446** | **101,186,808** | **112,083,728** | **111,466,946** | **58,980,793** | **64,122,932** |

**NOTE: Current DRR Work Plan Forecast through 2028 ONLY**

| Description | District | 5 yr Estimate | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|
| **Total DRR Projects** | **Total** | **$165,908,800** | **$19,000,000** | **$35,288,300** | **$32,881,000** | **$38,733,000** | **$40,006,500** |
| **TOR Enhanced ROW Widening** | **Total** | **$60,000,000** | **$12,000,000** | **$12,000,000** | **$12,000,000** | **$12,000,000** | **$12,000,000** |
| **Additional Tie Lines** | **Total** | **$10,580,000** | **$1,000,000** | **$3,325,000** | **$3,192,000** | **$1,463,000** | **$1,600,000** |
| **DACR Projects and Recloser Modernization** | **Total** | **$27,812,800** | **$1,000,000** | **$4,003,300** | **$8,911,000** | **$0** | **$13,898,500** |
| **Additional New Distribution Substation Sources** | **Total** | **$52,476,000** | **$3,000,000** | **$11,970,000** | **$4,788,000** | **$22,610,000** | **$10,108,000** |
| **Asset Renewal/Storm Hardening or Resiliency** | **Total** | **$15,040,000** | **$2,000,000** | **$3,990,000** | **$3,990,000** | **$2,660,000** | **$2,400,000** |
| | | | | | | | |
| **Additional Tie Lines (List of Larger Projects)** | **Total** | $10,580,000 | $1,000,000 | $3,325,000 | $3,192,000 | $1,463,000 | $1,600,000 |
| **Additional Tie Lines - Ashland** | Sub-total | $1,000,000 | $1,000,000 | $0 | $0 | $0 | $0 |
| Hayward Haldeman to Olive Hill Globe along Trumbo Rd and Hwy60 | Ashland | $1,000,000 | $1,000,000 | $0 | $0 | $0 | $0 |
| | | | | | | | |
| | | | | | | | |
| **Additional Tie Lines- Hazard** | Sub-total | $7,317,000 | $0 | $2,500,000 | $2,400,000 | $0 | $601,504 |
| Talcum - Dline 12m 34.5kV Conversion for ties to Beckham Hindman and Haddix Troublesome Cr. | Hazard | $6,517,000 | $0 | $2,500,000 | $2,400,000 | $0 | $0 |
| Various Smaller Rural Ties | | $800,000 | $0 | $0 | $0 | $0 | $601,504 |
| | | | | | | | |
| **Additional Tie Lines - Pikeville** | Sub-total | $2,263,000 | $0 | $0 | $0 | $1,100,000 | $601,504 |
| Johns Creek - Coleman Calloway Tie | Pikeville | $1,463,000 | $0 | $0 | $0 | $1,100,000 | $0 |
| Various Smaller Rural Ties | | $800,000 | $0 | $0 | $0 | $0 | $601,504 |
| | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **DACR/Recloser Moderization - Total** | **Total** | $27,812,800 | $1,000,000 | $4,003,300 | $8,911,000 | $0 | $13,898,500 |
| **DACR - Ashland** | Sub-total | **$3,005,800** | **$0** | **$2,010,000** | **$250,000** | **$0** | **$0** |
| Hayward - Lawton | Ashland | $1,330,000 | $0 | $1,000,000 | $0 | $0 | $0 |
| OliveHill - Globe | Ashland | $1,343,300 | $0 | $1,010,000 | $0 | $0 | $0 |
| Princess - US Cannonsburg | Ashland | $332,500 | $0 | $0 | $250,000 | $0 | $0 |
| Hitchins - Denton | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| Hitchins - Grayson | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| Hitchins - EK Road | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| Grayson - Landsdown | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| Grayson - Dixie Park | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | |
| | | | | | | | |
| **DACR - Hazard** | Subtotal | **$14,098,000** | **$0** | **$0** | **$3,750,000** | **$0** | **$6,850,000** |
| BECKHAM - CARR CREEK | Hazard | $731,500 | $0 | $0 | $550,000 | $0 | $0 |
| VICCO - REDFOX | Hazard | $665,000 | $0 | $0 | $500,000 | $0 | $0 |
| SOFT SHELL - VEST | Hazard | $731,500 | $0 | $0 | $550,000 | $0 | $0 |
| SOFT SHELL - LEBURN | Hazard | $665,000 | $0 | $0 | $500,000 | $0 | $0 |
| COLLIER - UPPER ROCKHOUSE | Hazard | $731,500 | $0 | $0 | $550,000 | $0 | $0 |
| COLLIER - LOWER ROCKHOUSE | Hazard | $133,000 | $0 | $0 | $100,000 | $0 | $0 |
| REEDY - DEANE | Hazard | $1,330,000 | $0 | $0 | $1,000,000 | $0 | $0 |
| BECKHAM - HINDMAN | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| TALCUM - CIRCUIT 1 | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| BLUEGRASS - WALKERTOWN | Hazard | $1,330,000 | $0 | $0 | $0 | $0 | $1,000,000 |
| BLUEGRASS - HAZARD | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| COMBS - AIRPORT GARDENS | Hazard | $1,330,000 | $0 | $0 | $0 | $0 | $1,000,000 |
| HAZARD - HAZARD | Hazard | $997,500 | $0 | $0 | $0 | $0 | $750,000 |
| BULAN - ARY-HEINER | Hazard | $731,500 | $0 | $0 | $0 | $0 | $550,000 |
| BULAN - AJAX-DWARF | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| BULAN - LOTTS CR. | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| JACKSON - S.JACKSON | Hazard | $731,500 | $0 | $0 | $0 | $0 | $550,000 |
| JACKSON - PANBOWL | Hazard | $665,000 | $0 | $0 | $0 | $0 | $500,000 |
| | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| **DACR - Pikeville** | Subtotal | **$5,719,000** | **$0** | **$0** | **$1,700,000** | **$0** | **$2,600,000** |
| ELWOOD -DORTON | Pikeville | $931,000 | $0 | $0 | $700,000 | $0 | $0 |
| ELWOOD - VIRGIE - IN | Pikeville | $665,000 | $0 | $0 | $500,000 | $0 | $0 |
| FORDSBRANCH - ROBINSON CR. | Pikeville | $665,000 | $0 | $0 | $500,000 | $0 | $0 |
| TOMWATKIN - DISTRIBUTION | Pikeville | $2,128,000 | $0 | $0 | $0 | $0 | $1,600,000 |
| SIDNEY - COBURN MTN. | Pikeville | $1,330,000 | $0 | $0 | $0 | $0 | $1,000,000 |
| FALCON - FALCO OIL SPRINGS | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| FALCON - BURNING FK. | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| INDEX - WEST LIBERTY | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| INDEX - HOSPITAL | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| W.PAINTSVILLE - PAINTSVILLE | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| W.PAINTSVILLE - STAFFORDSVILLE | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| W.PAINTSVILLE - PLAZA | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| KENWOOD | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| KENWOOD - AUXIER | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| KENWOOD - HAGERHILL | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| MAYO TRAIL - NIPPA | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| MAYO TRAIL - EUCLID | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| KIMPER - GRAPEVINE | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| FISHTRAP - DISTRIBUTION | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| KEYSER - STONECOAL | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| PIKEVILLE - CITY | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| PIKEVILLE - MAIN ST. | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| PIKEVILLE - CEDAR CR. | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| S.PIKEVILL - PIKEVILLE | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| S.PIKEVILLE - ISLAND CR. | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| S.PIKEVILLE - HOSPITAL | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| BELFRY - BELFRY | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| BELFRY - TOLER | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| NEW CAMP - SOUTH SIDE | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| MCKINNEY - GIBSON | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| SALISBURY - PRINTER | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| ALLEN - DISTRIBUTION | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| BETSYLAYNE _ TRAM | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | |
| **Recloser Modernization** | Subtotal | **$4,990,000** | **$1,000,000** | **$1,000,000** | **$1,000,000** | **$0** | **$1,000,000** |
| | | | | | | | |
| **Additional New Substation Projects - Total** | **Total** | **$52,476,000** | **$3,000,000** | **$11,970,000** | **$4,788,000** | **$22,610,000** | **$10,108,000** |
| **Substation Projects - Ashland** | Subtotal | **$23,807,000** | **$0** | **$0** | **$2,300,000** | **$12,000,000** | **$3,600,000** |
| | | | | | | | |
| Grays Br.-Increase Bank Size to 20MVA (2) Breakers | Ashland | $9,975,000 | $0 | $0 | $300,000 | $3,600,000 | $3,600,000 |
| Ramey Sta. - Relieve loading Howard Collins\ Mobile Issue | Ashland | $12,236,000 | $0 | $0 | $2,000,000 | $7,200,000 | $0 |
| Ramey Sta. - D line Exits | Ashland | $1,596,000 | $0 | $0 | $0 | $1,200,000 | $0 |
| RT. 645 Station Near Lawrence Co. Martin Co. Line (2030 -2031) | Ashland | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Substation Projects - Hazard** | Subtotal | **$14,970,000** | **$3,000,000** | **$9,000,000** | **$0** | **$0** | **$0** |
| | | | | | | | |
| Talcum - Land | Hazard | $500,000 | $500,000 | $0 | $0 | $0 | $0 |
| Talcum - New Station | Hazard | $14,470,000 | $2,500,000 | $9,000,000 | $0 | $0 | $0 |
| | | | | | | | |
| | | | | | | | |
| **Substation Projects - Pikeville** | Subtotal | **$13,699,000** | **$0** | **$0** | **$1,300,000** | **$5,000,000** | **$4,000,000** |
| | | | | | | | |
| Dorton 34kV Distribution Bank | Pikeville | $6,650,000 | $0 | $0 | $1,000,000 | $4,000,000 | $0 |
| Dorton 34kV to Elwood (Future Myra) 18kFT Rebuild | Pikeville | $0 | $0 | $0 | $0 | $0 | $0 |
| Stone 12kV Distribution Bank with 3-12kV CBs and Circuit Ties | Pikeville | $6,650,000 | $0 | $0 | $0 | $1,000,000 | $4,000,000 |
| Tom Watkins - purchase addl property | Pikeville | $399,000 | $0 | $0 | $300,000 | $0 | $0 |
| | | | | | | | |
| **Asset Renewal/Storm Hardening/Resiliency-Total** | **Total** | **$15,040,000** | **$2,000,000** | **$3,990,000** | **$3,990,000** | **$2,660,000** | **$2,400,000** |
| | | | | | | | |

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_11** | Provide the test-year depreciation expense related to decommissioning costs for fossil fuel-fired electric facilities. Provide all supporting calculations and documentation in Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible. |

**RESPONSE**

Per the settlement agreement approved in Case No. 2017-00179, the depreciation rates for Big Sandy and Mitchell do not include any amounts for final decommissioning. As such, there is no depreciation expense related to the final decommissioning costs included in the test year depreciation expense.

Witness: Brian K. West

Witness: Katharine I. Walsh

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_12** | Provide the rate base impact, including accumulated depreciation and accumulated deferred income taxes, of removing decommissioning costs for fossil fuel- fired electric facilities from depreciation rates. Provide all supporting calculations and documentation in Excel spreadsheet format, with all formulas, columns, and rows unprotected and fully accessible. |

**RESPONSE**

There are no final decommissioning costs included in the current depreciation rates or accumulated depreciation for Big Sandy in accordance with the settlement approved in Case No. 2017-00179. The depreciation rates for the Mitchell Plant included an amount for final decommissioning costs during the period of July 2015 through December 2017. Final decommissioning costs were removed from Mitchell depreciation rates in accordance with the settlement approved in Case No. 2017-00179. The rate base impact of removing the Mitchell Plant decommissioning costs for the period July 2015 – December 2017 would be an approximately $1.75 million net increase to rate base. Please also see KPCO_R_KPSC_PHDR_12_Attachment1.

Witness: Brian K. West

Witness: Katharine I. Walsh

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_13** | Provide the test year amount of PJM Interconnection LLC (PJM) Load Serving Entity Open Access Transmission Tariff (LSE OATT) expense without normalization. |

**RESPONSE**

Please see the response and references in KPSC 2-97. Annualized 2023 "PJM LSE OATT" expense is approximately $136.4 million and is comprised of $122.2 million test year level of expense + $14.2 million expense based on fixed, known, and measurable amounts in effect beginning January 1, 2023, and is consistent with prior Commission-approved treatment of PJM LSE OATT expenses.

Witness: Katharine I. Walsh

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_14** | Provide Kentucky Power's total storm damage restoration expenses for the last five years, separated by major and all other. Include in the response which expenses or events received deferral accounting and which did not. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_14_Attachment1 for the requested information.

Witness: Heather M. Whitney

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_15** | Provide a list of Kentucky Power's short-term and long-term debt, including each instrument's test-year ending balance. Include the annual cost rate for each instrument. |

**RESPONSE**

Please see Section V, Schedule 3, Workpaper S-3, at Page 1 of 3 for a list of Kentucky Power's long-term debt, and at Page 2 of 3 for Kentucky Power's short-term debt outstanding at the test-year end March 31, 2023, including the annual cost rate applicable to each instrument.

Witness: Franz D. Messner

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_16** | Provide the documentation or presentations provided to the Investment Review Committee (IRC) by Kentucky Power, Wheeling Power, Appalachian Power, Ohio Power, Indiana & Michigan Power and Kingsport Power, or AEP on behalf of the aforementioned operating companies, in the possession of Kentucky Power, for the years 2020 through 2023. |

**RESPONSE**

The Company respectfully objects to this request to the extent it requires providing information about affiliates of the Company that are not subject to the jurisdiction of the Kentucky Public Service Commission and that are subject to the jurisdiction of regulatory commissions in other state jurisdictions. The Company further objects to the extent the request is not reasonably calculated to lead to the discovery of admissible evidence. Like the Kentucky Power presentations that are being produced in response to this request, the IRC presentations of Wheeling Power, Appalachian Power, Ohio Power, Indiana & Michigan Power, and Kingsport Power do not contain any information regarding AEP's capital allocation decisions among its operating companies. Nor do the affiliates' IRC presentations contain any information about Kentucky Power.

Kentucky Power further respectfully objects to this data request to the extent it requires the production of attorney-client privileged communications or documents protected by the attorney work product doctrine, including legal analysis and advice regarding legal and regulatory issues, risks, and potential outcomes in then-pending or anticipated regulatory proceedings, and counsel's legal interpretation of statutes, regulations, and Commission orders. Kentucky Power is filing a privilege log identifying the documents with respect to which the privilege and doctrine are being asserted.

The Company further states that to the extent the Commission relies on any information contained in the documents provided in response to this request as evidence to support any of the Commission's findings in this matter or any other matter, the Company has not had the opportunity to provide any context or additional information that may be relevant to or necessary for the Commission's review of these documents. Nor will any Kentucky Power witness have the opportunity to be cross-examined in this proceeding regarding the contents of these documents.

Subject to and without waiving that privilege or doctrine, or any of the aforementioned objections, the Company states as follows:

Please see attachment KPCO_R_KPSC_PHDR_16_PublicAttachment1, KPCO_R_KPSC_PHDR_16_PublicAttachment2, and KPCO_R_KPSC_PHDR_16_PublicAttachment3 for the nonprivileged documents related to and in the custody and control of Kentucky Power that are responsive to this request. Kentucky Power did not participate in the 2022 IRC process due to the then-pending, Commission-approved, planned sale of Kentucky Power to Liberty Utilities during that time period; therefore, no responsive document exists for that year. Kentucky Power is seeking confidential treatment for the entirety of the nonprivileged attachments and is providing these documents with the expectation that they will be treated confidentially, based on the Commission's past treatment of similar information. Kentucky Power respectfully reserves the right to request to withdraw the documents should confidential treatment not be granted for the entirety of the documents.

Importantly, the information contained in these presentations is used for informational and business planning purposes, and the information may vary from or change over time as compared to actual performance or actual courses of action taken after the presentations were prepared. The information also should not, in some instances, be taken at face value and may require additional context. For example, the specific information related to the projected net dividends in the financial forecast sections is subject to change, may not represent the net dividend actually expected to be paid, and instead represents the result of a mathematical exercise to produce the amount that would be necessary to be paid to the parent in order to maintain the Company's debt-to-capital ratio in a given year, and therefore manage the cost of capital to customers.

Respondent: Counsel (as to legal aspects)

Witness: Brian K. West (as to factual aspects)

KPCO_R_KPSC_PHDR_16_PublicAttachment1 is confidential in its entirety.

KPCO_R_KPSC_PHDR_16_PublicAttachment2 is confidential in its entirety.

KPCO_R_KPSC_PHDR_16_PublicAttachment3 is confidential in its entirety.

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_17** | Refer to Application, Section III, Volume 1, Direct Testimony of Steven Fetter. Provide all workpapers, documentation, or reports referenced in the testimony. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_17_Attachments1 through 14.

Witness: Steven M. Fetter

20-Apr-2023 | 16:26 EDT

# American Electric Power Ratings Affirmed; Kentucky Power Downgraded To 'BBB' On Weaker Financials; Outlook Stable

- On April 17, 2023, American Electric Power Co. Inc. (AEP) and Liberty Utilities Co. mutually agreed to terminate the sale of Kentucky Power Co. (KPCo).
- As such, we affirmed our ratings on AEP, including its 'A-' long-term issuer credit rating (ICR). The outlook remains stable.
- Simultaneously, we lowered the ICR and issue-level ratings on KPCo by one notch to 'BBB' from 'BBB+'. At the same time, we removed KPCo ratings from CreditWatch, where we placed them with negative implications on Oct. 28, 2021. The outlook is stable.
- Our stable outlook on AEP reflects our expectations that the company's financial measures will improve but will consistently reflect very minimal financial cushion from its downgrade threshold. We expect the company will continue to prudently manage its regulatory risk such that it consistently maintains funds from operations (FFO) to debt that is at or slightly above 16% through 2025.

NEW YORK (S&P Global Ratings) April 20, 2023--S&P Global Ratings today took the rating actions listed above.

We expect that AEP's financial measures will significantly improve.

AEP's 2022 FFO debt was 14.9%, considerably below our 16% downgrade threshold. We expect financial measures will significantly improve in 2023, primarily reflecting the company's sale of its unregulated contracted renewable assets, equity units conversion of about $850 million, and rate case orders in Oklahoma and Virginia. However, despite our anticipation for additional material equity issuances in 2024 and 2025, we expect the company's financial measures will reflect only very minimal financial cushion above our downgrade threshold because of robust capital spending. Over the next three years, we expect annual capital spending to average about $8.5 billion. This is a significant increase from the company's historical capital spending levels. In 2021 and 2022, AEP's capital spending was about $5.7 billion and $6.7 billion, respectively. As such, the company must continue to consistently manage its regulatory risk at all of its regulatory jurisdictions. Any unexpected outcomes beyond our base case could weaken financial measures below our downgrade threshold, potentially leading to a weakening of credit quality.

We continue to assess AEP's business risk profile as excellent.

We assess AEP's business risk profile as being in the middle of the range for the excellent category, relative to peers. The company is mostly a large and geographically diversified regulated utility that serves about 5.6 million customers across 11 states. The company's ongoing reduction of its coal-fired generation aligns with the industry's transition toward a clean energy future. We expect a modest improvement in the business risk profile with the sale of unregulated contracted renewables portfolio occurring in the second half of 2023.

The downgrade of KPCo to 'BBB' from 'BBB+' reflects the company's stand-alone weakening financial measures.

In 2021 and 2022, FFO to debt was 11.6% and 11.4%, respectively, significantly below our downgrade threshold of 15%. We reflect this weakening in financial measures by applying a negative comparable ratings analysis modifier. Going forward, we expect a modest improvement to stand-alone financial measures, reflecting rate case increases and a potential securitization, pending legislative and regulatory approvals.

We revised our assessment of Indiana Michigan Power Co's (IMP) financial risk profile downward to significant from intermediate.

This reflects our expectation of a modest weakening of financial measures primarily reflecting robust capital spending. We now expect IMP's stand-alone FFO to debt to be about 18%-23% through 2025. We also expect IMP's capital spending to gradually rise to about $1 billion by 2025. We expect IMP's discretionary cash flow to remain negative and anticipate it will continue to depend on having consistent access to the capital markets.

American Electric Power Co. Inc.

The stable rating outlook on AEP reflects our expectations that the company's financial measures will improve but will consistently reflect very minimal financial cushion from its downgrade threshold. We expect the company will continue to prudently manage its regulatory risk such that it consistently maintains FFO to debt that is at or slightly above 16% through 2025.

We could lower our ratings on AEP within the next 24 months if:

- Its financial performance does not improve as expected such that FFO to debt remains below 16%; or
- Its business risk increases because of ineffective management of regulatory risk or an increase in its riskier nonregulated investments.

While less likely, we could upgrade AEP if its financial performance materially improves such that FFO to debt is consistently greater than 20% without any increase to business risk.

Kentucky Power Co.

The stable outlook on KPCo reflects timely recovery of approved capital expenditure and fuel costs, supporting the company's cash flow stability.. Our baseline forecast for 2023-2025 assumes KPCo's stand-alone FFO to debt to be in the range of 11%-15%.

We could lower our ratings on KPCo in the next 24 months if:

- Parent AEP is downgraded; or
- KPCo's stand-alone financial performance weakens such that FFO to debt weakens to below 11%.

We could upgrade KPCo if its stand-alone financial performance improves such that FFO to debt is greater than 15%, without an increase to business risk.

American Electric Power Co. Inc.

ESG credit indicators: E-3, S-3, G-2

Indiana Michigan Power Co.

ESG credit indicators: E-4, S-3, G-2

Kentucky Power Co.

ESG credit indicators: E-4, S-3, G-2

## Related Criteria

INFRASTRUCTURE AND PROJECT FINANCE

MOODY'S
INVESTORS SERVICE

ISSUER COMMENT
18 April 2023

Send Your Feedback

Contacts

Nana Hamilton +1.212.553.9440
*VP-Senior Analyst*
nana.hamilton@moodys.com

Michael G. Haggarty +1.212.553.7172
*Associate Managing Director*
michael.haggarty@moodys.com

CLIENT SERVICES

Americas 1-212-553-1653

Asia Pacific 852-3551-3077

Japan 81-3-5408-4100

EMEA 44-20-7772-5454

# American Electric Power Company, Inc.

## Termination of Kentucky operations sale has no immediate credit impact

On 17 April 2023, American Electric Power Company, Inc. (AEP) announced the termination of a pending transaction to sell the company's Kentucky operations to Liberty Utilities Co., a subsidiary of Algonquin Power & Utilities Corp (not rated) for an enterprise value of $2.65 billion, including about $1.3 billion of estimated debt at closing. The failure to close the transaction will have no immediate impact on AEP's credit because of the small size of its Kentucky operations (about 4% of rate base and 2% of operating cash flow) and the anticipated replacement of the lost proceeds with cash from a pending sale of AEP's unregulated renewable portfolio.

AEP had planned to revisit its equity financing plans following closing of the Kentucky sale and of the sale of its unregulated renewable portfolio for net proceeds of about $1.2 billion. With the termination of the Kentucky transaction, however, AEP plans to maintain the equity issuances of approximately $600 million - $700 million annually currently in its financing plan. We continue to expect the company to generate a ratio of operating cash flow excluding changes in working capital (CFO pre-WC) to debt of between 13% and 15%, which we view as supportive of AEP's current Baa2 rating.

AEP's Kentucky operations include vertically integrated subsidiary Kentucky Power Company (Baa3 stable) and AEP Kentucky TransCo which is part of AEP Transmission Company, LLC (A2 stable). Kentucky Power is AEP's weakest utility subsidiary from a credit perspective, with cash flow that has historically been constrained by persistent underearning in an economically challenged service territory. The utility generated a ratio of CFO pre-WC to debt of 10.7% in 2022, up from an average of 6.9% in the prior three years, relative to the 10% CFO pre-WC to debt ratio threshold we have established for a possible downgrade. The historical financial weakness was driven by several factors including weak economic conditions, the coronavirus pandemic, severe weather, and purchased power agreement (PPA) related deferrals. While credit metrics improved in 2022, cash flow benefitted from a change in pension and postemployment benefit reserves.

In December 2022, the Kentucky Public Service Commission (KPSC) approved Kentucky Power's request to recover deferred purchased power costs associated with the utility's Rockport power plant unit power agreement (UPA). Kentucky Power was also authorized to include an allowed non-fuel, non-environmental Rockport UPA expense of $22.8 million in base rates to earn its authorized ROE in 2023 following the end of UPA in December 2022.

Kentucky Power plans to file a rate case in June 2023, with rates effective in January 2024, which we expect will also address the recovery of about $75 million of deferred storm costs.

Furthermore, Kentucky Power plans to utilize existing legislation to pursue securitization to recover retirement costs associated with its Big Sandy power plant. Assuming supportive regulatory outcomes, and considering the December 2022 expiration of the relatively high cost Rockport lease agreement and AEP's stated focus on economic development in its Kentucky service territory, we expect Kentucky Power to generate a ratio of CFO pre-WC to debt above 10% going forward. The outcome of Kentucky Power's next rate case will help inform our view of the state of AEP's regulatory relationship with the KPSC following the sale termination.

Headquartered in Columbus, Ohio, AEP is a large electric utility holding company with nine vertically integrated or retail transmission and distribution utility subsidiaries operating in eleven states. The company also operates transmission companies within the eastern and southwestern regions of the United States. AEP has a regulated rate base of around $59 billion and serves about 5.6 million customers.

INFRASTRUCTURE AND PROJECT FINANCE

MOODY'S INVESTORS SERVICE

CREDIT OPINION
29 June 2022

Update

Send Your Feedback

RATINGS

**Kentucky Power Company**

| | |
|---|---|
| Domicile | Ashland, Kentucky, United States |
| Long Term Rating | Baa3 |
| Type | LT Issuer Rating |
| Outlook | Stable |

*Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.*

Contacts

Nana Hamilton +1.212.553.9440
*VP-Senior Analyst*
nana.hamilton@moodys.com

Domenic Giovannone +1.212.553.1647
*Associate Analyst*
domenic.giovannone@moodys.com

Michael G. Haggarty +1.212.553.7172
*Associate Managing Director*
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
*MD - Global Infrastructure & Cyber Risk*
james.hempstead@moodys.com

# Kentucky Power Company

Update to credit analysis

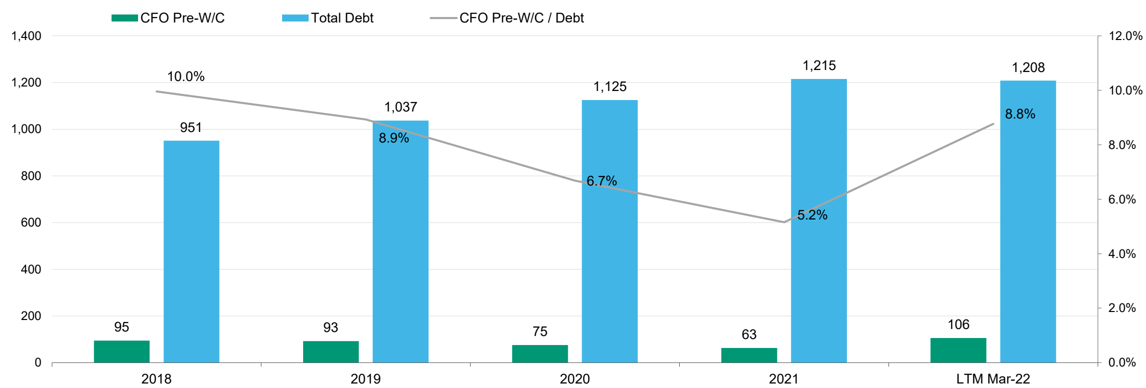
## Summary

Our view of Kentucky Power Company's (KPCo) credit reflects its risk profile as a vertically integrated electric utility operating in eastern Kentucky. Our opinion reflects the lower cash flow and cash flow-based credit metrics the company has demonstrated in recent years as a result of under earning and required refunds in an economically challenged service territory. Recent credit metrics are also being impacted by storm activity. KPCo's 2021 ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt was particularly low, at 5.2%, due to costs associated with unusually severe winter weather in February 2021. Excluding the impact of this unusual weather, the company's 2021 CFO pre-WC to debt ratio would be about 10%. We expect the utility's credit metrics to improve after 2022, including a ratio of CFO pre-WC to debt ratio above 10%, following the expiration of a relatively high cost lease agreement. The stable outlook on KPCo reflects our view that, barring major changes to the utility's financial condition or debt levels as a result of its pending acquisition discussed below, we do not expect the sale to adversely affect the current rating.

## Recent Developments

In October 2021, KPCo's parent, American Electric Power Company (AEP, Baa2 stable), agreed to sell KPCo and AEP Kentucky Transco to Liberty Utilities Co., a subsidiary Algonquin Power and Utilities Corp (not rated) for an enterprise value of approximately $2.8 billion, including about $1.3 billion of estimated debt at closing. In May 2022, the Kentucky Public Service Commission (KPSC) approved the sale. The sale was expected to close in the second quarter of 2022 following approvals required from the West Virginia Public Service Commission (WVPSC) and the Federal Energy Regulatory Commission (FERC). However, approval from the WVPSC of operating and ownership agreements related to the Mitchell power plant is still pending and FERC has indicated that it will require up to 180 days to render a decision following receipt of the WVPSC approval. AEP expects the sale to close in summer 2022 but closing could occur as late as December 2022.

Exhibit 1
**Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt ($ in millions)**




*Source: Moody's Financial Metrics*

## Credit strengths

» Reasonable regulatory relationship in Kentucky

» Position as part of the AEP family to be replaced by smaller but still diverse Liberty utility family

## Credit challenges

» Increasing capital expenditures and cash deferrals will continue to pressure already low credit metrics

» Relatively weak service territory in eastern Kentucky

» Elevated carbon transition risk

## Rating outlook

KPCo's stable rating outlook recognizes that its low cash flow-based credit metrics will continue to be impacted by a relatively weak service territory, recent severe weather, and a significant capital expenditure program. Cash flow is also being pressured by deferrals agreed to in the utility's 2018 decided rate case and an accelerated return of excess deferred income taxes. We expect KPCo's annual ratio of CFO pre-WC to debt to remain below 10% through 2022. Beyond 2022, the expiration of a relatively high cost lease agreement should help this metric to move to the low teens. The stable outlook also reflects our view that, barring major changes to the utility's financial condition or debt levels as a result of the acquisition by Liberty, we do not expect the sale to adversely affect the current rating.

## Factors that could lead to an upgrade

» An improvement in economic conditions, or a reduction in operating or capital expenses, leading to improved financial performance

» A sustained ratio of CFO pre-WC to debt above 13% with a ratio of CFO pre-WC less dividends above 11%

» A material reduction in leverage at the utility

## Factors that could lead to a downgrade

» A deterioration in KPCo's relationship with its regulator

» An increase in capital or operating expenses that KPCo is unable to recover on a timely basis

» A ratio of CFO pre-WC to debt remaining below 10% beyond 2022

## Key indicators

Exhibit 2
**Kentucky Power Company Indicators [1]**

| | Dec-18 | Dec-19 | Dec-20 | Dec-21 | LTM Mar-22 |
|---|---|---|---|---|---|
| CFO Pre-W/C + Interest / Interest | 3.4x | 3.2x | 2.9x | 2.7x | 3.9x |
| CFO Pre-W/C / Debt | 10.0% | 8.9% | 6.7% | 5.2% | 8.8% |
| CFO Pre-W/C – Dividends / Debt | 10.0% | 8.4% | 6.7% | 5.2% | 8.8% |
| Debt / Capitalization | 45.6% | 46.4% | 47.0% | 48.1% | 47.5% |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
*Source: Moody's Financial Metrics*

## Profile

Kentucky Power Company (KPCo), a vertically integrated electric utility company headquartered in Ashland, Kentucky, is a wholly owned subsidiary of AEP, with about $2.0 billion in rate base (4% of AEP's total) and 2021 revenue of about $650 million (about 4% of AEP's total revenue). The utility is primarily regulated by the Kentucky Public Service Commission (KPSC). AEP has agreed to sell KPCo to Liberty Utilities Company, a holding company of regulated utilities, with AEP expecting the closing to occur in summer 2022.

## Detailed credit considerations

### *Reasonable regulatory relationship*

Moody's views the regulatory environment in Kentucky as moderately supportive of long-term credit quality. KPCo benefits from a suite of cost recovery mechanisms that help reduce regulatory lag, including a fuel adjustment clause, rider recovery for certain PJM transmission costs, and environmental recovery riders which enable utilities in the state to earn a return on construction work in progress. In addition, utilities in Kentucky can start to collect interim rates approximately six months after filing a rate case if the KPSC has not acted on it. Despite these positive factors, the KPSC's recent decisions have been impacted by the weak economic conditions in KPCo's service territory and have been less supportive of utility credit quality.

In January 2021, the KPSC authorized a $52.4 (later modified to $52.7) million base rate increase premised on a 9.3% return on equity (ROE). The case was initiated in June of 2020 when KPCo filed a request for a $65 million increase in base rates premised on a 10% ROE. The KPSC's order shortened the authorized period for the return of excess deferred income tax not subject to normalization to 3 years versus a previously (2018) authorized period of 18 years.

AEP Generating Company (AEGCo, not rated) sells 30% of the power available to AEGCo from units 1 (of which it owns a 50% interest) and 2 (of which it leases a 50% interest) of the Rockport Power Plant to KPCo. This sale is pursuant to an assignment between KPCo and sister company Indiana Michigan Power Company (I&M, A3 positive), which has a unit power agreement (UPA) with AEGCo for all the power available to AEGCo from the two Rockport plant units. Consequently, KPCo pays to AEGCo the same amounts which I&M would have paid to AEGCo under the terms of the UPA. In its last rate case, KPCo requested recovery of $50 million in deferred expenses related to the Rockport plant power purchase agreement (PPA) over a 5-year period beginning in December 2022. KPCo had agreed to defer this $50 million over five years, through 2022 as part of its 2018 decided rate case. The KPSC decided to defer KPCo's request regarding the Rockport PPA recovery period and mechanism to a future proceeding.

The proceeding to determine recovery of the deferred $50 million of PPA costs will be initiated after KPCo makes a written filing identifying the capacity replacement for Rockport unit 2. We expect the company will make that filing after the close of its pending sale. In the interim, the KPSC has allowed KPCo to retain savings from the December 2022 Rockport unit 2 lease expiration through at least 2023 when the utility is required to file its next rate case. KPCo's parent, AEP, has reached an agreement with the Rockport unit 2 lessor to acquire the unit at the end of its lease term in 2022, thus the capacity will remain within the AEP organization.

### *Cash flow credit metrics are under pressure*

Prior to 2018, KPCo's key cash flow based financial credit metrics were strong for its credit quality, including CFO pre-WC to debt in the mid-to-high teens. Since then, cash flow metrics have declined fairly dramatically as the utility's debt load increased in conjunction with its capital program, while sales volumes have been negatively impacted by challenging economic conditions.

For the past three years, KPCo's ratio of CFO pre-WC to debt has been below the 10% financial metric threshold we have established for a possible downgrade. As noted above, weak economic conditions, the coronavirus pandemic, severe weather, and PPA related deferrals have all contributed to this result. Excluding the impact of unusual winter weather, the company's 2021 CFO pre-WC to debt ratio would be about 10%. The company intends to request recovery of approximately $60 million of storm costs in its next base rate case. We expect the utility's credit metrics to remain low in 2022 but the expiration of the relatively high cost Rockport lease agreement should help the ratio of CFO pre-WC to debt metric to move to the low teens beyond 2022.

As a subsidiary of AEP, the company has had flexibility with regards to dividend policy including the credit supportive ability to retain cash in response to lower cash flow. In 2019, a minimal $5 million dividend was paid; however in 2018, 2020 and 2021, no dividends were paid to AEP. As a result, KPCo's ratios of CFO pre-WC less dividends to debt have essentially been equal to its relatively low ratios of CFO pre-WC to debt.

Upon completion of the sale of KPCo, Liberty Utilities' plan for the utility, including capital spending and financial policy, could change, but barring any significant changes, we do not expect the sale to adversely affect KPCo's current rating.

### *Sale of KPCo contingent on new Mitchell plant operating and ownership agreements*

KPCo's owned generation includes 50% of the 1,560 MW Mitchell coal power plant, with the other 50% owned by AEP subsidiary Wheeling Power Company (WPCo). In July 2021, the KPSC rejected KPCo's request to implement an Effluent Limitation Guidelines (ELG) compliance plan which would allow the Mitchell plant to operate beyond 2028. However, in August 2021, the West Virginia Public Service Commission (WVPSC) approved the plan.

In response to the conflicting decisions of the two regulatory commissions, KPCo and WPCo filed for approval of new operating and ownership agreements for the Mitchell plant, which is currently operated by KPCo. The filings request that operation of the plant be transferred to WPCo and the employees who operate the Mitchell plant be transferred from KPCo to WPCo. Furthermore, WPCo would be obligated to purchase KPCo's 50% interest in the Mitchell plant at the end of 2028 unless both companies decide to retire the plant earlier or WPCo elects before 31 December 2027 to retire the plant by 31 December 2028. AEP's sale of the Kentucky operations is contingent on approval by the KPSC, WVPSC and FERC of the new Mitchell plant operating and ownership agreements. In May 2022, the KPSC approved the sale of AEP's Kentucky operations as well as the new Mitchell operating and ownership agreements with conditions including on the buyout provisions under the ownership agreement. Approval from the WVPSC is pending and AEP intends to file for FERC approval once it receives approval from the WVPSC. FERC has indicated that it will require up to 180 days to render a decision and while AEP expects the sale to be completed in summer 2022, closing could occur as late as December 2022.

### *Service territory economy remains depressed*

According to Moody's Economy, Kentucky's economic recovery has cooled off and the state remains an underperformer compared to most regional peers. Manufacturing gains, specifically in the automotive sector will continue to be muted until supply-chain bottlenecks ease. These complications will leave consumer services driving the majority of job gains in the short-term. However, longer term, capital injections will support higher levels of factory employment, including large investments for electric vehicle factories from Ford, Kentucky's third largest employer.

KPCo has been actively working with state and federal officials to foster economic development in eastern Kentucky that will bring job opportunities, increase customer retention, and support load growth. However, these efforts have yet to begin to meaningfully contribute to utility load growth or cash flow. Approximately 24% of KPCo's 2021 retail energy revenues were from industrial customers. Total weather normalized retail load remained flat in 2021 following an 8.4% decline in 2020, and declines of 2.1% in 2019, 0.7% in 2018, and 1.7% in 2017.

## ESG considerations

Environmental considerations incorporated into our credit analysis for KPCo are primarily related to carbon regulations. As an integrated electric utility, KPCo's generation ownership places it at a higher risk profile than transmission and distribution companies. In addition, its significant coal generation ownership results in a higher ESG risk profile than other vertically integrated electric utilities.

KPCo's total owned generation capacity of 1,060 MW includes a 50% ownership in the coal-fired Mitchell plant (780 MW) and the gas-fired Big Sandy Unit 1 (280 MW). KPCo also purchases approximately 393 MW from its affiliate AEP Generating Company's share of the Rockport coal plant under a long-term unit power agreement, bringing its overall capacity mix to 20% natural gas and 80% coal. Both units of the Rockport plant are currently expected to be retired in 2028.

Social risks are primarily related to demographic and societal trends, including the risk that public concern about environmental, social or affordability issues could result in adverse regulatory or political outcomes.

Governance is driven by that of KPCo's parent and will be driven by that of Liberty Utilities and ultimate parent Algonquin Power and Utilities Corp. once the sale of KPCo is completed. Conservative financial policies and risk management that ensure a strong financial position are key to managing KPCo's environmental and social risks.

## Liquidity analysis

KPCo's liquidity is adequate. For the twelve months ending 31 March 2022, KPCo generated approximately $38 million of cash from operations, invested $170 million in capital expenditures and paid no dividends to parent AEP, resulting in a negative free cash flow (FCF) of approximately $131 million. We expect KPCo to remain free cash flow negative over the next 12 to 18 months.

Although KPCo does not benefit from a dedicated external credit facility, the company does have access to its parent company AEP's liquidity through participation in its utility money pool. As of 31 March 2022, KPCo's borrowing limit under the money pool was $180 million and the utility had borrowed approximately $94 million. KPCo has historically utilized AEP's $750 million receivable securitization facility, made up of a $125 million and $625 million facility expiring September 2023 and 2024 respectively. Due to the pending sale to Liberty Utilities, KPCo terminated selling receivables to AEP Credit in January 2022 and recorded an allowance for uncollectible accounts in the first quarter of 2022 for receivables no longer sold to AEP Credit. KPCo's nearest maturities include a $125 million term loan due in September 2022 and a $75 million term loan due in October 2022. We expect these to be refinanced.

AEP's consolidated liquidity is adequate. AEP currently has two syndicated credit facilities, a $4.0 billion facility expiring in March 2027, and a $1.0 billion facility expiring in March 2024. As of 31 March 2022, AEP had approximately $1.88 billion of outstanding commercial paper utilizing capacity under the $4 billion facility. AEP is not required to make a representation with respect to either material adverse change or material litigation in order to borrow under its revolving credit facilities. The facility contains a covenant requiring that AEP's consolidated debt to capitalization (as defined) not exceed 67.5%. AEP states that the contractually defined ratio was 57.8% at 31 March 2022.

## Appendix

Exhibit 3
**Peer Comparison [1]**

| | Kentucky Power Company Baa3 (Stable) | | | Duke Energy Kentucky, Inc. Baa1 (Stable) | | | Louisville Gas & Electric Company A3 (Stable) | | | Kentucky Utilities Co. A3 (Stable) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (In US millions) | FYE Dec-20 | FYE Dec-21 | LTM Mar-22 | FYE Dec-19 | FYE Dec-20 | LTM Dec-21 | FYE Dec-19 | FYE Dec-20 | LTM Dec-21 | FYE Dec-21 | FYE Dec-21 | LTM Mar-22 |
| Revenue | 550 | 646 | 667 | 452 | 520 | 520 | 1,456 | 1,569 | 1,569 | 1,690 | 1,826 | 1,882 |
| CFO Pre-W/C | 75 | 63 | 106 | 125 | 145 | 145 | 535 | 543 | 543 | 646 | 664 | 683 |
| Total Debt | 1,125 | 1,215 | 1,208 | 885 | 921 | 921 | 2,290 | 2,417 | 2,417 | 2,851 | 2,938 | 2,934 |
| CFO Pre-W/C + Interest / Interest | 2.9x | 2.7x | 3.9x | 5.5x | 6.3x | 6.3x | 7.1x | 7.7x | 7.7x | 6.7x | 7.0x | 7.2x |
| CFO Pre-W/C / Debt | 6.7% | 5.2% | 8.8% | 14.1% | 15.7% | 15.7% | 23.4% | 22.5% | 22.5% | 22.7% | 22.6% | 23.3% |
| CFO Pre-W/C – Dividends / Debt | 6.7% | 5.2% | 8.8% | 14.1% | 15.7% | 15.7% | 16.3% | 14.5% | 14.5% | 15.6% | 14.1% | 13.6% |
| Debt / Capitalization | 47.0% | 48.1% | 47.5% | 48.0% | 45.8% | 45.8% | 38.5% | 38.7% | 38.7% | 38.2% | 38.0% | 37.9% |

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
*Source: Moody's Financial Metrics*

Exhibit 4

**Cash flow and credit measures [1]**

| CF Metrics | Dec-18 | Dec-19 | Dec-20 | Dec-21 | LTM Mar-22 |
|---|---|---|---|---|---|
| As Adjusted | | | | | |
| **FFO** | **119** | **130** | **127** | **131** | **134** |
| +/- Other | -25 | -38 | -52 | -68 | -28 |
| **CFO Pre-WC** | **95** | **93** | **75** | **63** | **106** |
| +/- ΔWC | 27 | -10 | -9 | 10 | -15 |
| **CFO** | **122** | **82** | **66** | **73** | **91** |
| - Div | 0 | 5 | 0 | 0 | 0 |
| - Capex | 138 | 163 | 157 | 169 | 174 |
| **FCF** | **-16** | **-86** | **-91** | **-96** | **-83** |
| | | | | | |
| (CFO Pre-W/C) / Debt | 10.0% | 8.9% | 6.7% | 5.2% | 8.8% |
| (CFO Pre-W/C - Dividends) / Debt | 10.0% | 8.4% | 6.7% | 5.2% | 8.8% |
| FFO / Debt | 12.6% | 12.6% | 11.3% | 10.8% | 11.1% |
| RCF / Debt | 12.6% | 12.1% | 11.3% | 10.8% | 11.1% |
| | | | | | |
| Revenue | 642 | 619 | 550 | 646 | 667 |
| Interest Expense | 40 | 42 | 39 | 36 | 37 |
| Net Income | 54 | 50 | 40 | 50 | 62 |
| Total Assets | 2,465 | 2,612 | 2,734 | 2,894 | 2,894 |
| Total Liabilities | 1,735 | 1,834 | 1,911 | 2,020 | 1,994 |
| Total Equity | 730 | 778 | 823 | 874 | 900 |

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
*Source: Moody's Financial Metrics*

## Rating methodology and scorecard factors

Exhibit 5
Kentucky Power Company

| Regulated Electric and Gas Utilities Industry [1][2] | Current LTM 3/31/2022 | | Moody's 12-18 Month Forward View As of Date Published [3] | |
|---|---|---|---|---|
| **Factor 1 : Regulatory Framework (25%)** | **Measure** | **Score** | **Measure** | **Score** |
| a) Legislative and Judicial Underpinnings of the Regulatory Framework | A | A | A | A |
| b) Consistency and Predictability of Regulation | Baa | Baa | Baa | Baa |
| **Factor 2 : Ability to Recover Costs and Earn Returns (25%)** | | | | |
| a) Timeliness of Recovery of Operating and Capital Costs | Baa | Baa | Baa | Baa |
| b) Sufficiency of Rates and Returns | Baa | Baa | Baa | Baa |
| **Factor 3 : Diversification (10%)** | | | | |
| a) Market Position | Ba | Ba | Ba | Ba |
| b) Generation and Fuel Diversity | B | B | B | B |
| **Factor 4 : Financial Strength (40%)** | | | | |
| a) CFO pre-WC + Interest / Interest (3 Year Avg) | 3.0x | Ba | 4x - 4.5x | Baa |
| b) CFO pre-WC / Debt (3 Year Avg) | 6.8% | Ba | 8% - 13% | Ba |
| c) CFO pre-WC – Dividends / Debt (3 Year Avg) | 6.7% | Ba | 8% - 13% | Baa |
| d) Debt / Capitalization (3 Year Avg) | 46.9% | Baa | 45% - 50% | Baa |
| **Rating:** | | | | |
| Scorecard-Indicated Outcome Before Notching Adjustment | | Baa3 | | Baa3 |
| HoldCo Structural Subordination Notching | | | | |
| a) Scorecard-Indicated Outcome | | Baa3 | | Baa3 |
| b) Actual Rating Assigned | | Baa3 | | Baa3 |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2022 (LTM)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard Risk Grid for Financial Strength
*Source: Moody's Financial Metrics*

## Ratings

Exhibit 6

| Category | Moody's Rating |
|---|---|
| **KENTUCKY POWER COMPANY** | |
| Outlook | Stable |
| Issuer Rating | Baa3 |
| Senior Unsecured | Baa3 |
| **PARENT: AMERICAN ELECTRIC POWER COMPANY, INC.** | |
| Outlook | Stable |
| Senior Unsecured | Baa2 |
| Jr Subordinate | Baa3 |
| Commercial Paper | P-2 |

*Source: Moody's Investors Service*

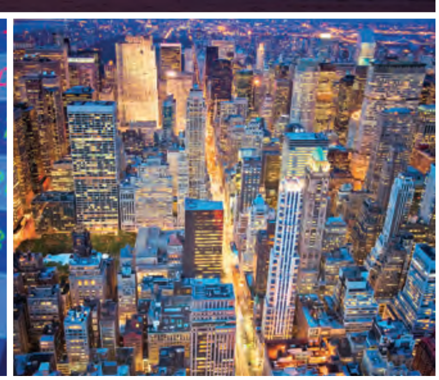
REPORT NUMBER 1330050

MOODY'S
INVESTORS SERVICE

EEI
Edison Electric
INSTITUTE

# 2022
# Financial Review

## Annual Report of the U.S. Investor-Owned Electric Utility Industry


Thank you to the following EEI Power Member for sponsoring the 2022 Financial Review.
POWERPLAN®
From the leading provider of financial reporting technology for asset-intensive industries.
Cloud
Managed
Services
Reduce risk. Accelerate time to value.
Move to the cloud with confidence and gain the freedom to focus on what you do best.
Fixed-Asset Accounting | Income Tax | Property Tax |
Lease Regulatory Reporting | Capital Budgeting and Planning
info@powerplan.com | (678) 223-2800
powerplan.com

Edison Electric INSTITUTE

# 2022 FINANCIAL REVIEW

ANNUAL REPORT
OF THE U.S. INVESTOR-OWNED
ELECTRIC UTILITY INDUSTRY

## About EEI and the Financial Review

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than 7 million jobs in communities across the U.S. and contributes 5 percent to the nation's GDP. The 2022 Financial Review is a comprehensive source for critical financial data covering 39 investor-owned electric companies whose stocks are publicly traded on major U.S. stock exchanges. The report also includes data on five additional companies that provide regulated electric service in the United States but are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States. These 44 companies are referred to throughout the publication as the U.S. Investor-Owned Electric Utilities. Please refer to page 76 for a list of these companies.

# Contents

## Highlights of 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| FINANCIAL ($ Millions) | 2022 | 2021r | % Change |
|---|---|---|---|
| Total Operating Revenues | $424,428 | $366,615 | 15.8% |
| Utility Plant (Net) | $1,418,389 | $1,335,697 | 6.2% |
| Total Capitalization | $1,368,875 | $1,293,058 | 5.9% |
| Earnings Excluding Non-Recurring and Extraordinary Items | $51,221 | $51,335 | (0.2%) |
| Dividends Paid, Common Stock | $31,016 | $30,075 | 3.1% |

r = revised  Note: Percent changes may reflect rounding.

## Abbreviations and Acronyms

| | |
|---|---|
| AFUDC | Allowance for Funds Used During Construction |
| BTU | British Thermal Unit |
| CFTC | Commodity Futures Trading Commission |
| CPI | Consumer Price Index |
| DOE | Department of Energy |
| DOJ | Department of Justice |
| DPS | Dividends per share |
| EEI | Edison Electric Institute |
| EIA | Energy Information Administration |
| EITF | Emerging Issues Task Force |
| EPA | Environmental Protection Agency |
| EPS | Earnings per share |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| IPP | Independent Power Producer |
| IRS | Internal Revenue Service |
| ISO | Independent System Operator |
| ITC | Independent Transmission Company |
| kWh | Kilowatt-hour |
| M&A | Mergers & Acquisitions |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NARUC | National Association of Regulatory Utility Commissioners |
| NERC | North American Electric Reliability Corporation |
| NOx | Nitrogen Oxide |
| NOAA | National Oceanic & Atmospheric Administration |
| NRC | Nuclear Regulatory Commission |
| O&M | Operations and Maintenance |
| PSC | Public Service Commission |
| PUC | Public Utility Commission |
| PUHCA | Public Utility Holding Company Act |
| PURPA | Public Utility Regulatory Policies Act |
| ROE | Return on Equity |
| RTO | Regional Transmission Organization |
| SEC | Securities and Exchange Commission |
| $SO_2$ | Sulfur Dioxide |
| T&D | Transmission & Distribution |

## Company Categories

Two categories are used throughout this publication that group companies based on their percentage of total assets that are regulated. These categories are used to provide an informative framework for tracking financial trends:

**Regulated:** 80% or more of total assets are regulated.

**Mostly Regulated:** Less than 80% of total assets are regulated.

Note: In prior editions of the Financial Review, a “Diversified” category was included for companies with less than 50% of total assets that are regulated. Some tables with historical data therefore include a “Diversified” category.

# President's Letter

## 2022 Financial Review

In January 1933, EEI began representing America's investor-owned electric companies, just as electricity truly was beginning to revolutionize daily life and to propel our nation's economy. Ninety years later, we stand at a global energy inflection point—and demand for electricity continues to grow. In fact, U.S. electricity output hit a record annual high last year: an astonishing 4,142,901 gigawatt-hours, up 2.8 percent from 2021, and 0.7 percent above the previous record year of 2018.

Today, EEI's member companies remain focused on ensuring that customers have the energy they need when and where they need it, affordably and reliably, as we work to get this energy as clean as we can as fast as we can. And, we have fully embraced a strategy that will deliver secure and resilient clean energy across our economy.

In 2021, Congress delivered a once-in-a-generation investment in America's infrastructure with passage of the Bipartisan Infrastructure Law. Last year, lawmakers reaffirmed this commitment to addressing climate change with passage of the Inflation Reduction Act and its nearly $272 billion in clean energy tax credits. EEI strongly supported both laws, and we continue to lead implementation efforts to ensure that electric companies and state governments are taking advantage of these crucial investments in America's infrastructure.

While we continue to highlight the significance of these monumental new laws for our customers and for our member companies, we recognize that we face headwinds as well. Our suppliers and our customers continue to experience inflation levels that we have not seen for decades. At the same time, geopolitical tensions remain high with Russia's ongoing war in Ukraine. This continues to create fuel supply risks, while also impacting supply chains and significantly increasing cyber and physical security threats.

Despite these challenges and others, we are focused on the opportunities before us—and we are certain that our industry's future is bright. Today—just as we were 90 years ago—we are committed to demonstrating Power by Association℠ and to seizing the moment to deliver enduring benefits for our customers.

Thanks largely to the clean energy leadership of EEI's member companies, carbon emissions from the U.S. electric power sector today are as low as they were almost 40 years ago, while electricity use has climbed 73 percent since then. Already, 50 EEI member companies have announced ambitious emissions reduction commitments, 41 of which aim for net-zero or equivalent by 2050 or sooner. We are proud that more than 40 percent of our nation's electricity now comes from clean, carbon-free sources, including nuclear energy, hydropower, wind, and solar energy.

EEI's long-held position is that we need to take an economy-wide approach to reducing carbon emissions. This means transitioning more of the U.S. economy to clean, efficient electric energy—starting with the industrial and transportation sectors, especially as the latter has been the leading source of carbon emissions in the United States since 2016.

There are more than 3 million EVs already on U.S. roads, and EEI projects there will be at least 26 million on our roadways in 2030. That increase will require approximately 140,000 EV fast charging ports across the country—a 10-fold increase over today. EEI's member companies are investing more than $4 billion in programs to accelerate electric transportation, including the deployment of EV charging infrastructure.

For electric companies, the EEI-AGA ESG Sustainability Template lends itself to telling the story of our member companies' clean energy transition, the risks and opportunities that lie ahead, and their plans to manage them. Almost 7 years ago, EEI established the first-of-its-kind, sector-wide ESG reporting template working with our member companies, investors, and other key stakeholders. Today, our industry's ESG leadership has enabled EEI to work with the U.S. Securities and Exchange Commission as it establishes workable ESG climate reporting and cyber reporting and governance rules.

We also are working every day to improve energy grid security, reliability, and resiliency, and we continue to strengthen cyber and physical defenses and to enhance preparedness. Our strong industry-government partnership, coordinated through the CEO-led Electricity Subsector Coordinating Council, continues to be critical to accomplishing our shared goal of protecting the grid against all threats.

Recent events, including extreme weather events, reinforce the continued need for strategic and responsible investments in adaptation, hardening, and resilience (AHR). Over the past decade, EEI's member companies have invested more than $1 trillion in critical energy infrastructure. And, in 2022 alone, nearly $30 billion was invested in AHR initiatives to strengthen the nation's transmission and distribution infrastructure.

While investments in AHR have increased significantly over the past decade, more investments are needed to meet the challenges of climate change and to enhance the overall reliability and resilience of the grid. The benefits of smart investments in AHR are clear and allow electric companies, communities, and customers to be better equipped to operate through challenging conditions. In Florida, for example, the state's hardened energy infrastructure largely withstood a direct hit by Hurricane Ian last year. Moreover, the investments made in smarter energy infrastructure at the distribution level helped to avoid hundreds of thousands of customer outages—and significantly sped restoration times for customers who were impacted.

It is critical that electric companies can continue to make needed investments today that will help them to deliver a resilient clean energy future. EEI continues our advocacy for stable, constructive policies that support our member companies' infrastructure investments. Related to this, we are asking the U.S. Treasury Department to implement the Corporate Alternative Minimum Tax without unduly impacting electricity customers or undermining needed investment in grid infrastructure.

As you will see in this year's Financial Review, EEI's member companies continue to build upon a strong financial foundation. The industry's average credit rating was BBB+ for the ninth straight year in 2022, after increasing from the BBB average that previously had held since 2004. This improved credit quality greatly supports the continued level of elevated capital expenditures, which set an eleventh consecutive record high of $147.7 billion in 2022. We continue to be America's most capital-intensive industry.

The EEI Index returned 1.2 percent for 2022, outperforming the major averages. The S&P 500 Index returned -18.3 percent, the Dow Jones Industrial Average returned -7.0 percent, and the Nasdaq Composite saw a steep -33.5 percent decline. The EEI Index has produced a positive total return in 17 of the last 20 years, with returns of greater than 10 percent in 13 of the 17 positive years.

Our industry also extended its long-term trend of widespread and consistent dividend increases last year, with a total of 34 companies increasing their dividend in 2022. The percentage of companies that raised or reinstated their dividend in 2022 was 87 percent, up from 82 percent in 2021 and aligned with the 85 percent to 93 percent range seen from 2015 through 2020. Our industry's dividend payout ratio was 73.0 percent for the 12 months ended December 31, 2022, leading among the other major U.S. business sectors. As of December 31, 2022, 38 of the 39 companies in the EEI Index were paying a common stock dividend.

As we celebrate 90 years of Power by Association—and as we begin our next 90 years by engaging on our ambitious agenda—EEI and our member companies will be the catalyst for delivering resilient clean energy and for achieving a clean energy economy quickly and affordably.

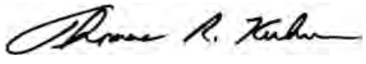
Earlier this year, I announced my plans to step down as EEI President after more than 30 years. Few people have been as fortunate as I have to be associated with such a talented and dedicated team and to be part of such a vital industry. I am incredibly proud of what EEI and our member companies have accomplished together during my tenure.

EEI's mission to deliver Power by Association will remain unchanged. I am excited by what the future holds for our customers, our country, and our member companies—and I am excited to remain actively involved in our industry.

Over the years I have been involved in our industry, I have seen incredible transformation and progress—and I know that this transformation and this progress will never stop. Our industry's focus on our customers remains our North Star, and, by keeping them at the forefront, we will achieve amazing things.

We truly value the partnership that we share with the financial community.

Thomas R. Kuhn



President
Edison Electric Institute

# Capital Markets

## Stock Performance

Major market indices rebounded later in the year after three straight quarters of losses. The Dow Jones Industrial Average, a composite of 30 underlying large-capitalization companies, gained 15.8% while the more broadly diversified S&P 500 Index gained 7.3%. The tech-heavy Nasdaq, the epicenter of late 2021's market froth, edged down a modest 1.6%. Utilities were right in the middle; the EEI Index gained 8.8% for the quarter.

The full-year 2022 picture shows utilities far ahead of major indices on a relative basis. The Dow Jones Industrial Average returned -7.0% in 2022, the S&P 500 returned -18.3% and the Nasdaq fell deep into a bear market with a 33.5% decline.

### Economic Growth Rebounds After Weak First Half

Markets in the second half of the year were powered higher in part by evidence that economic strength rebounded from weakness in 2022's first half. In late October, the Bureau of Economic Analysis (BEA) released its first estimate of Q3 2022 real GDP at positive 2.6%; this compared to -1.6% in Q1 and -0.6% for

### 2022 Index Comparison

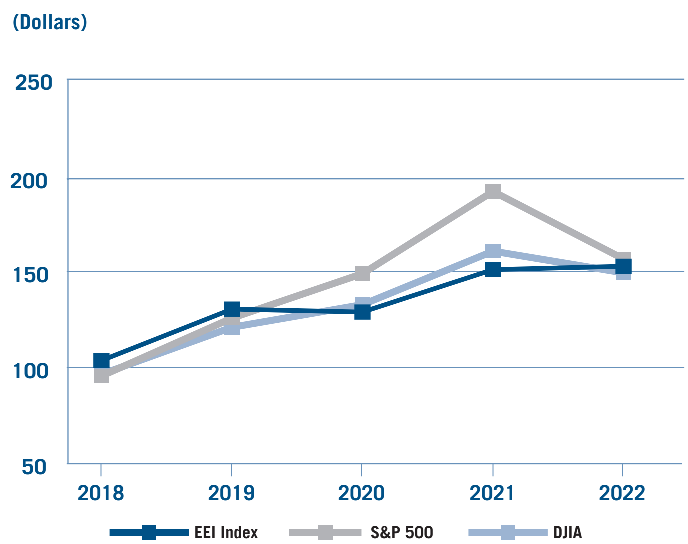
| | |
|---|---|
| **EEI Index** | **1.2** |
| Dow Jones Industrials | (7.0) |
| S&P 500 | (18.3) |
| Nasdaq Composite Index* | (33.5) |

* Price gain/(loss) only. Other indices show total return.

Source: EEI Finance Department and S&P Global Market Intelligence.

### Comparison of the EEI Index, S&P 500, and DJIA Total Return 1/1/18–12/31/22

REFLECTS REINVESTED DIVIDENDS




All returns are annual.
Note: Assumes $100 invested at closing prices December 31, 2017.

Source: EEI Finance Department and S&P Global Market Intelligence.

## EEI Index Top 10 Performers
### Twelve-month period ending 12/31/2022

| Company | Total Return % | Category |
|---|---|---|
| PG&E Corporation | 33.9 | R |
| Sempra Energy | 20.3 | R |
| Consolidated Edison, Inc. | 15.6 | R |
| Unitil Corporation | 15.1 | R |
| Pinnacle West Capital Corporation | 12.9 | R |
| American Electric Power Company, Inc. | 10.4 | R |
| PNM Resources, Inc. | 10.2 | R |
| CenterPoint Energy, Inc. | 10.1 | R |
| Avista Corporation | 8.8 | R |
| NorthWestern Corporation | 8.5 | R |

Note: Return figures include capital gains and dividends.
Source: EEI Finance Department.

## Sector Comparison 2022 Total Shareholder Return

| Sector | Total Return % |
|---|---|
| Oil & Gas | 61.5% |
| Utilities | 2.9% |
| **EEI Index** | **1.2%** |
| Healthcare | -4.7% |
| Telecommunications | -6.5% |
| Basic Materials | -6.9% |
| Financials | -13.3% |
| Industrials | -13.5% |
| Consumer Goods | -23.2% |
| Consumer Services | -30.6% |
| Technology | -34.9% |

Source: EEI Finance Dept., Dow Jones & Company, Yahoo! Finance.

Q2. The Q3 figure was revised upward to 2.9% in the late November release and higher again to 3.2% in the BEA's third estimate, released on December 22.

### Headline Inflation Moderates

Investor sentiment was also lifted by hints that inflation may be moderating. Inflation measured by the headline consumer price index (CPI) for urban consumers peaked in June at 8.9% and held above 8% in July, August, and September. Data released in Q4 showed a steady decline to 7.8% in October, 7.1% in November and 6.4% in December. The CPI excluding volatile food and energy (which economists often cite as a more meaningful inflation metric) hovered near 6% all year and peaked in September at 6.6%, yet it too eased to a December reading of 5.7%.

### Fed Hikes but Bond Yields Ease

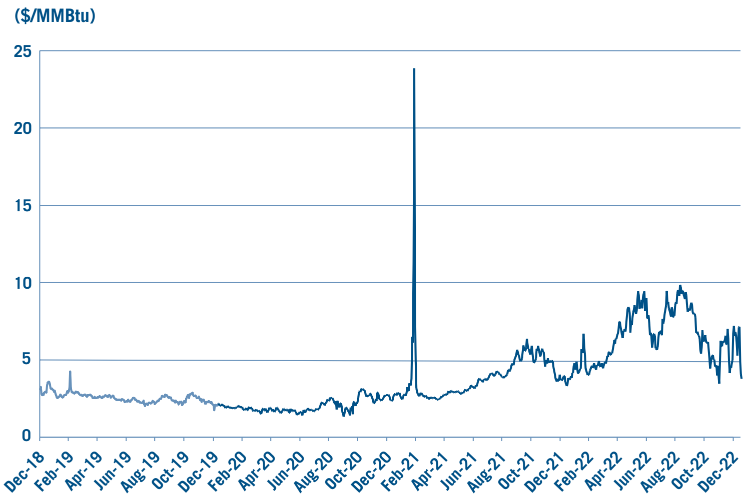
Persistently sticky inflation data was enough to cause the U.S. Federal Reserve to extend it's 2022 rate hike campaign, hiking the overnight federal funds rate by 75 basis points on November 2 and 50 basis points on December 14. The Fed's seven rate hikes in 2022 took the fed funds rate from near 0% in March to 4.3% in late December, making for one of the steepest rate-hike campaigns in modern history.

Bond markets spent Q4 wondering how to react to Fed hikes and cooler inflation data. The U.S. 10-year Treasury yield rose in October, reaching 4.2%, but then fell steadily to 3.4% by early December before climbing back to 3.8% at year-end, and corporate bond yields were steady for the quarter. Falling inflation numbers and steady bond yields gave investors enough confidence to push markets up after three quarters of losses.

### Fuel Cost Inflation Drives up Power Prices

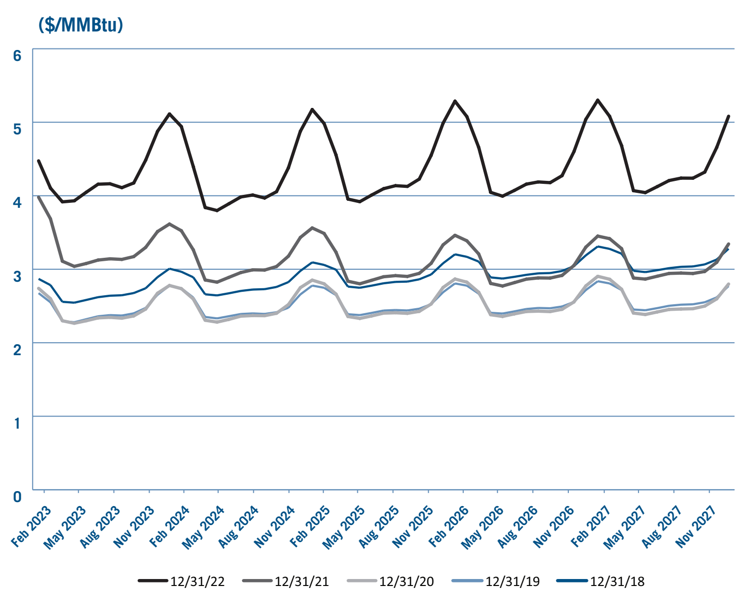
While surging inflation and higher energy costs are a global phenomenon, the trend is impacting U.S. electricity costs. Natural gas powers about 38% of generation nation-

## Natural Gas Spot Prices - Henry Hub
12/31/18 through 12/31/22



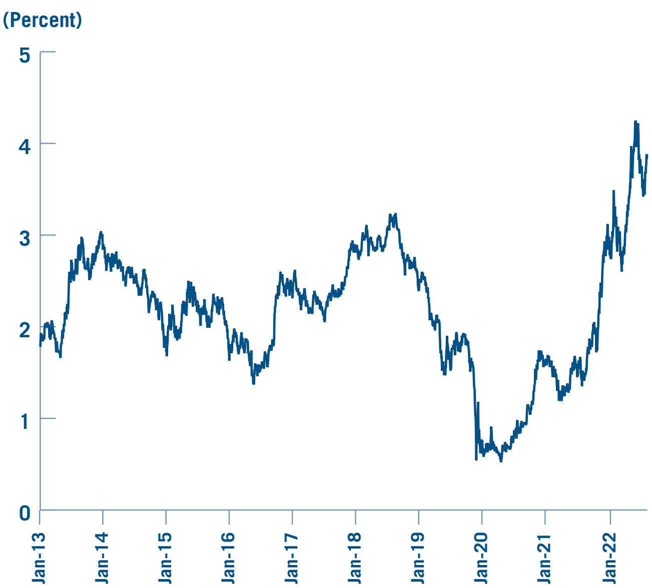

Source: S&P Global Market Intelligence.

## NYMEX Natural Gas Futures
February 2023 through December 2027




Source: S&P Global Market Intelligence.

**10-Year Treasury Yield**
**1/1/13 through 12/31/22**




Source: U.S. Federal Reserve.

wide and coal about 22%. Natural gas prices have been rising since the middle of 2020 and jumped in 2022 to their highest levels since 2013. Regulated utilities pass fuel costs through to rates under state regulation and have little near-term control over the fuel element of the utility bill. EIA data shows the average cost of natural gas for electricity generation rose 110% year-to-year in Q2 and 86% in Q3. EIA data shows that comparable coal costs rose 11% year-to-year in Q1, 16% in Q2 and 22% in Q3.

Natural gas comparisons eased in tandem with CPI inflation in Q4, echoed by the decline in spot gas prices seen in the graph *Natural Gas Spot Prices*. The average cost of natural gas for electric generation rose only 5.0% in October and was unchanged year-to-year in November. However, inflation in the average cost of coal for electricity generation remained high, at 22.0% in October and 25.9% in November.

While electricity rates in aggregate nationwide were mostly flat from 2008 through 2019, the average retail price of electricity nationwide according to EIA data rose 7% year-to-year in 2022's Q1, more than 12% in Q2 and almost 17% in Q3. Cost pressures continued in Q4 with year-to-year increases at 14.0% in October and at 11.8% in November.

Utility managements and Wall Street analysts are closely watching rate reviews and regulators' reactions to integrated resource plans to see if cost pressures on utility bills spoil consumers' or regulators' support for the clean energy capex that drives earnings growth.

### Conference Season

Wall Street analysts produce considerable reporting on utility management presentations at the investment conferences that populate the fall season. EEI's Financial Conference in November is one of these. In recent years, Wall Street's take has been consistently upbeat, focusing on the virtuous cycle that enabled low natural gas prices, stable customer bills, growing public support for clean energy and for CO2 emissions cuts, federal clean renewable energy tax incentives, and operations and maintenance (O&M) cost savings from smart-grid investments to fund the growing capital spending that translates into earnings growth. Projected secular earnings growth rates analysts cited for utilities steadily edged higher over the past decade from 4%-5% up to 5%-7% and 6%-8% in some cases.

This year's conference season produced widespread discussion of inflation, higher interest rates, higher fuel costs, pension costs pressures, regulatory concern over the impacts of aggressive capex on customer bills, and the stability of long-term earnings growth rates across the industry. Several analyst reports used the phrase "non-linearities" to reference the modest cuts in 2023 earnings guidance or longer-term growth outlooks that came out of earnings calls and conference presentations by a handful of utilities. The phrase was also a buzzword for investors' new scrutiny of company outlooks for risks of earnings speed bumps or downshifts to expected growth rates.

### Secular Tailwinds

Yet despite scattered earnings outlook cuts, Wall Street research coverage also affirmed the industry's fundamental growth picture remains robust.

The Inflation Reduction Act of 2022 (IRA) offers broad support to the nation's clean energy agenda and may add to pre-existing rate base growth opportunities for electric utilities. In EEI's view, the IRA places the United States at the forefront of global efforts to drive down carbon emissions, especially when paired with the historic funding included in the bipartisan infrastructure law. It also provides much-needed certainty to electric utilities over the next decade, as they work to deploy clean energy and carbon-free technologies.

## 2022 Returns By Quarter

| Index | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| EEI Index | 4.8 | (4.9) | (6.7) | 8.8 |
| Dow Jones Industrial Average | (4.0) | (10.9) | (6.2) | 15.8 |
| S&P 500 | (4.6) | (16.1) | (4.9) | 7.3 |
| Nasdaq Composite* | (9.0) | (23.0) | (3.5) | (1.6) |

| Category | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| All Companies | 5.2 | (3.8) | (8.3) | 10.7 |
| Regulated | 6.4 | (3.6) | (8.2) | 10.0 |
| Mostly Regulated | (0.0) | (5.0) | (9.0) | 14.3 |

* Price gain/loss only. Other indices show total return.
For the Category comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).

Source: EEI Finance Department, S&P Global Market Intelligence.

## 2022 Category Comparison

| Category | Return (%) |
|---|---|
| **EEI Index** | **2.7** |
| Regulated | 3.6 |
| Mostly Regulated | (1.1) |

* Returns shown here are unweighted averages of constituent company returns. The EEI Index return shown in the 2022 Index Comparison table is cap-weighted.

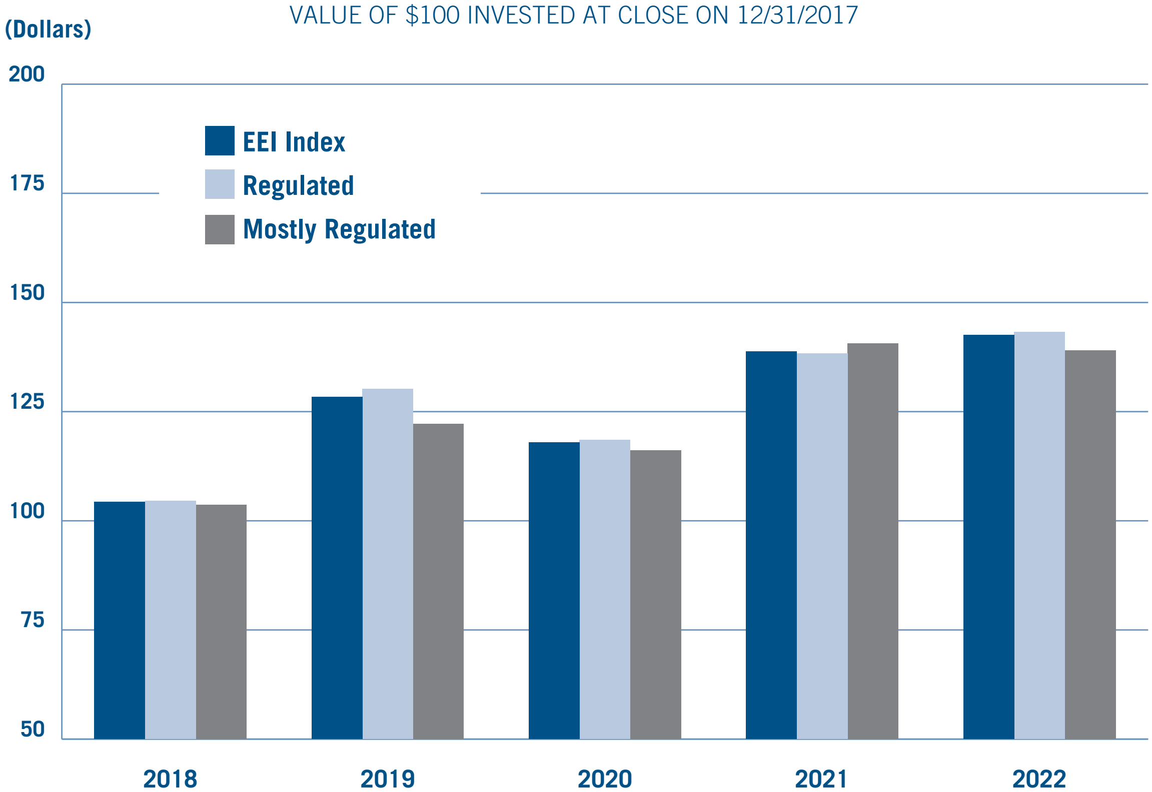
Source: EEI Finance Department, S&P Global Market Intelligence, and company annual reports.

Analysts noted that, despite regulatory scrutiny of customer bill pressures in some regions, there is little evidence that commissions are generally any less supportive of the nation's clean energy agenda and the economic stimulus that clean energy and reliability-related capex brings to service territories. The potential boost to secular load growth from widespread adoption of electric vehicles also remains a possibly strong tailwind. Several utilities have cited the onshoring of U.S. manufacturing and economic development as drivers of strong load growth in their service territories. A few cited electricity demand from large data centers.

Long-term growth rarely occurs without occasional setbacks and challenges. And utilities offered investors a relative safe haven and a positive total return in 2022's market weakness — that's more or less what they're expected to do. It's impossible to predict what inflation and interest rates will do in 2023, but as the year begins it seems reasonable to believe the nation's clean energy revolution is still in the early innings with investor-owned utilities as key players in the game.

## Comparative Category Total Annual Returns 2018–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES,
VALUE OF $100 INVESTED AT CLOSE ON 12/31/2017




| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| EEI Index Annual Return (%) | 4.28 | 23.06 | (8.07) | 17.62 | 2.74 |
| EEI Index Cumulative Return ($) | 104.28 | 128.32 | 117.96 | 138.74 | 142.55 |
| Regulated EEI Index Annual Return | 4.55 | 24.56 | (9.01) | 16.72 | 3.59 |
| Regulated EEI Index Cumulative Return | 104.55 | 130.22 | 118.49 | 138.30 | 143.26 |
| Mostly Regulated EEI Index Annual Return | 3.62 | 17.87 | (4.95) | 21.09 | (1.15) |
| Mostly Regulated EEI Index Cumulative Return | 103.62 | 122.14 | 116.09 | 140.58 | 138.97 |

- For the Category Comparison, straight, equal-weight averages are used (i.e., not market-cap-weighted).
- Cumulative Return assumes $100 invested at closing prices on December 31, 2017.

Source: EEI Finance Dept., S&P Global Market Intelligence.

## Market Capitalization at December 31, 2022 (in $MM)

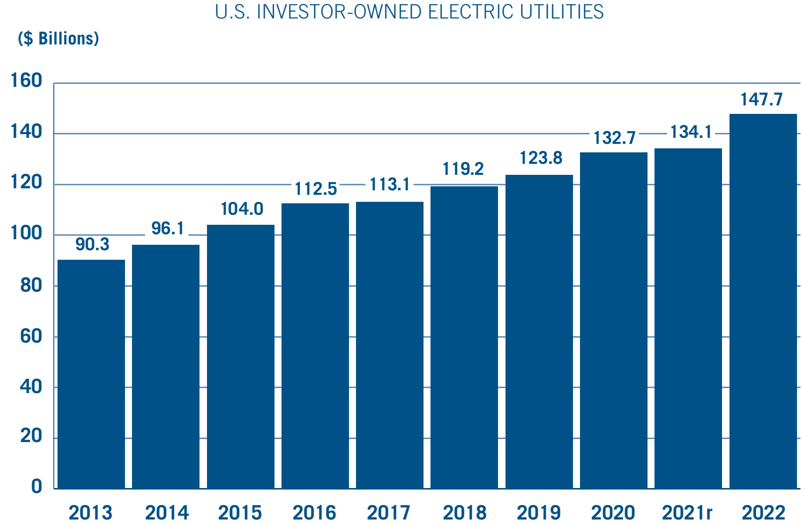
U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Company Name | Ticker | Market Cap. | % of Total |
|---|---|---|---|
| NextEra Energy, Inc. | NEE | 164,901 | 16.49% |
| Duke Energy Corporation | DUK | 79,302 | 7.93% |
| Southern Company | SO | 77,266 | 7.73% |
| Dominion Energy, Inc. | D | 51,055 | 5.11% |
| American Electric Power Company, Inc. | AEP | 48,779 | 4.88% |
| Sempra Energy | SRE | 48,637 | 4.86% |
| Exelon Corporation | EXC | 42,711 | 4.27% |
| Xcel Energy Inc. | XEL | 38,420 | 3.84% |
| Consolidated Edison, Inc. | ED | 33,797 | 3.38% |
| PG&E Corporation | PCG | 32,309 | 3.23% |
| Public Service Enterprise Group Inc. | PEG | 30,451 | 3.05% |
| WEC Energy Group, Inc. | WEC | 29,572 | 2.96% |
| Eversource Energy | ES | 29,117 | 2.91% |
| Edison International | EIX | 24,303 | 2.43% |
| FirstEnergy Corp. | FE | 23,948 | 2.40% |
| Ameren Corporation | AEE | 22,977 | 2.30% |
| Entergy Corporation | ETR | 22,888 | 2.29% |
| DTE Energy Company | DTE | 22,683 | 2.27% |
| PPL Corporation | PPL | 21,513 | 2.15% |
| CenterPoint Energy, Inc. | CNP | 18,879 | 1.89% |
| CMS Energy Corporation | CMS | 18,340 | 1.83% |
| AVANGRID, Inc. | AGR | 16,622 | 1.66% |
| Evergy, Inc. | EVRG | 14,468 | 1.45% |
| Alliant Energy Corporation | LNT | 13,858 | 1.39% |
| NiSource Inc. | NI | 11,146 | 1.11% |
| Pinnacle West Capital Corporation | PNW | 8,609 | 0.86% |
| OGE Energy Corp. | OGE | 7,918 | 0.79% |
| MDU Resources Group, Inc. | MDU | 6,170 | 0.62% |
| IDACORP, Inc. | IDA | 5,465 | 0.55% |
| Hawaiian Electric Industries, Inc. | HE | 4,581 | 0.46% |
| Black Hills Corporation | BKH | 4,563 | 0.46% |
| Portland General Electric Company | POR | 4,374 | 0.44% |
| PNM Resources, Inc. | PNM | 4,201 | 0.42% |
| ALLETE, Inc. | ALE | 3,684 | 0.37% |
| NorthWestern Corporation | NWE | 3,341 | 0.33% |
| Avista Corporation | AVA | 3,247 | 0.32% |
| MGE Energy, Inc. | MGEE | 2,546 | 0.25% |
| Otter Tail Corporation | OTTR | 2,442 | 0.24% |
| Unitil Corporation | UTL | 822 | 0.08% |
| **Total Industry** | | **999,904** | **100%** |

Source: EEI Finance Department and S&P Global Market Intelligence.

## Capital Expenditures 2013–2022

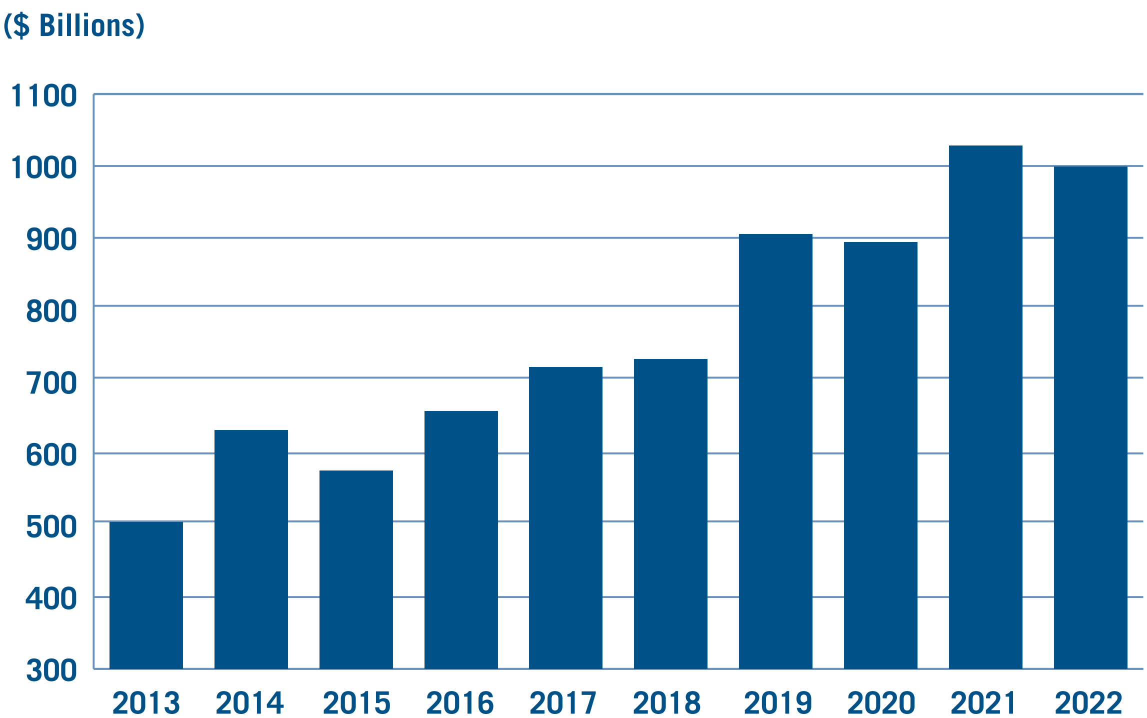
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

# EEI Index Market Capitalization 2013–2022

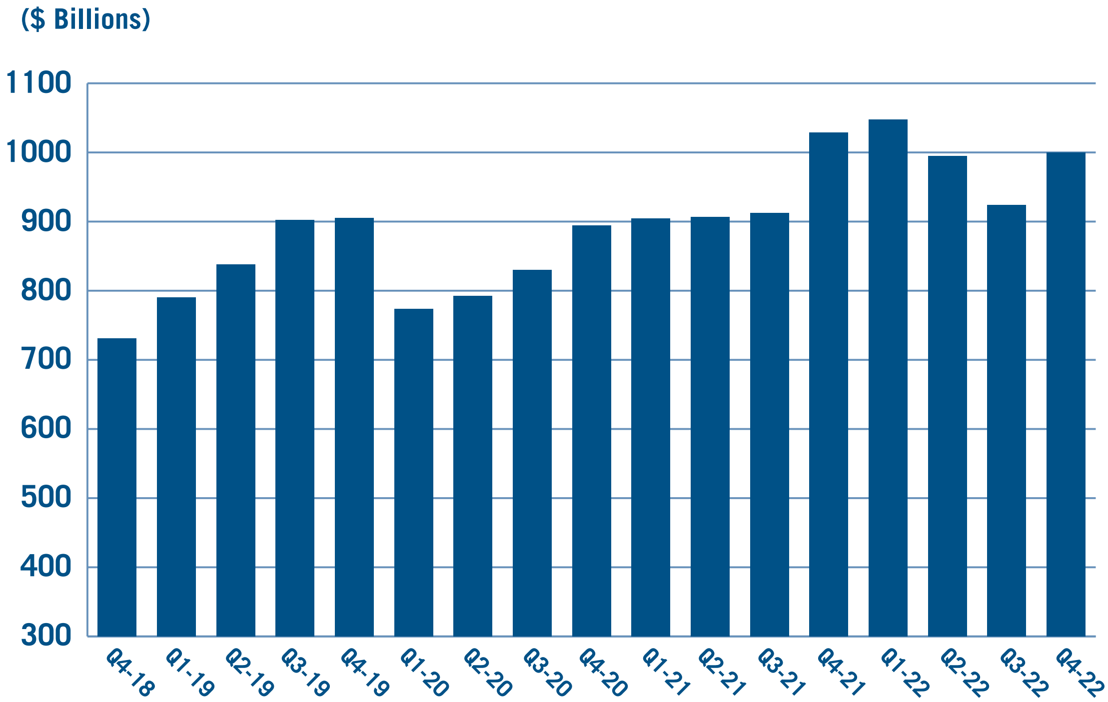



Note: Results are as of December 31 of each year.

Source: EEI Finance Department and S&P Global Market Intelligence.

# EEI Index Market Capitalization

## December 31, 2018–December 31, 2022




Source: EEI Finance Department and S&P Global Market Intelligence.

## Dividends

The investor-owned electric utility industry continued its long-term trend of widespread dividend increases in 2022. A total of 34 companies increased or reinstated their dividend compared to 32 in 2021, 34 in 2020, 37 in 2019, 39 in 2018 and 36 to 40 companies annually from 2012 through 2017. There was one dividend reduction compared to zero in 2021 and two in 2020.

The percentage of companies that raised or reinstated their dividend in 2022 was 87%, up from 82% in 2021 and aligned with the 85% to 93% range seen from 2015 through 2020. By contrast, only 27 of the 65 utilities tracked by EEI increased their dividend in 2003, just prior to the passage of legislation that reduced dividend tax rates. The percentages noted above are drawn

### Dividend Patterns 1996–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| | Raised | No Change | Lowered | Omitted* | Reinstated | Not Paying | Total | Dividend Payout Ratio |
|---|---|---|---|---|---|---|---|---|
| 1996 | 48 | 44 | 2 | 1 | 1 | 2 | 98 | 70.7% |
| 1997 | 40 | 45 | 6 | 2 | – | 3 | 96 | 84.2% |
| 1998 | 40 | 37 | 7 | – | – | 5 | 89 | 82.1% |
| 1999 | 29 | 45 | 4 | – | 3 | 2 | 83 | 74.9% |
| 2000 | 26 | 39 | 3 | 1 | – | 2 | 71 | 63.9% |
| 2001 | 21 | 40 | 3 | 2 | – | 3 | 69 | 64.1%** |
| 2002 | 26 | 27 | 6 | 3 | – | 3 | 65 | 67.5% |
| 2003 | 26 | 24 | 7 | 2 | 1 | 5 | 65 | 63.7% |
| 2004 | 35 | 22 | 1 | – | – | 7 | 65 | 67.9% |
| 2005 | 34 | 22 | 1 | 1 | 2 | 5 | 65 | 66.5% |
| 2006 | 41 | 17 | – | – | – | 6 | 64 | 63.5% |
| 2007 | 40 | 15 | – | – | 3 | 3 | 61 | 62.1% |
| 2008 | 36 | 20 | 1 | – | 1 | 1 | 59 | 66.8% |
| 2009 | 31 | 23 | 3 | – | – | 1 | 58 | 69.6% |
| 2010 | 34 | 22 | – | – | – | 1 | 57 | 62.0% |
| 2011 | 31 | 22 | – | 1 | 1 | – | 55 | 62.8% |
| 2012 | 36 | 14 | – | – | 1 | – | 51 | 64.2% |
| 2013 | 36 | 12 | 1 | – | – | – | 49 | 61.5% |
| 2014 | 38 | 9 | 1 | – | – | – | 48 | 60.4% |
| 2015 | 39 | 7 | – | – | – | – | 46 | 67.0% |
| 2016 | 40 | 4 | – | – | – | – | 44 | 62.9% |
| 2017 | 38 | 4 | – | 1 | – | – | 43 | 64.0% |
| 2018 | 39 | 1 | 1 | – | – | 1 | 42 | 63.9% |
| 2019 | 37 | 2 | – | – | – | 1 | 40 | 62.6% |
| 2020 | 34 | 2 | 2 | – | – | 1 | 39 | 65.3% |
| 2021 | 32 | 6 | – | – | – | 1 | 39 | 62.7% |
| 2022 | 34 | 3 | 1 | – | – | 1 | 39 | 70.8% |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Average of the Increased Dividend Actions ***** | 5.3% | 5.7% | 5.8% | 5.6% | 5.6% | 5.7% | 5.1% | 5.1% | 4.8% | 5.2% |
| **Average of the Declining Dividend Actions ***** | (41.0%) | (34.5%) | NA | NA | NA | (79.8%) | NA | (40.6%) | NA | (51.8%) |

* Omitted in current year. This number is not included in the Not Paying column.

** * Prior to 2000: Total industry dividends/total industry earnings. Starting in 2000: Average of all companies paying dividend.

*** Excludes companies that omitted or reinstated dividends.

2022 current year figures reflect dividend changes (raised, lowered, etc.) through 12/31/2022 and earnings and dividends through 12/31/2022 (payout ratio).

Source: S&P Global Market Intelligence and EEI Finance Department from a dataset that begins in 1988. Mergers and acquisitions reduced the number of publicly traded utilities included in the EEI Index from 65 in 2003 to 39 at year-end 2022.

As shown in Dividend Patterns table, 38 of the 39 publicly traded utilities in the EEI Index were paying a common stock dividend as of December 31, 2022. Each company is limited to one action per year in the table. For example, if a company raised its dividend twice during a year that counts as one in the Raised column. Electric utilities generally use the same quarter each year for dividend changes, with Q1 being the most common.

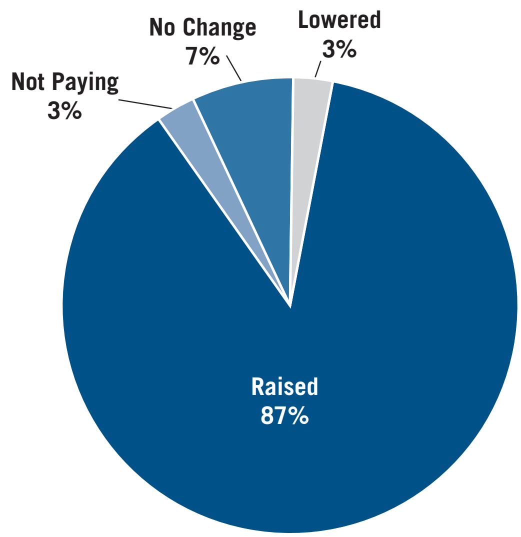
### 2022 Increases Average 5.2%

The average dividend increase in 2022 was 5.2%, with a range of 1.0% to 12.2% and a median increase of 5.6%. PNM Resources (12.2% including both its Q1 and Q4 raises), CenterPoint Energy (11.8% including both its Q3 and Q4 increases) and NextEra Energy (+10.4% in Q1) posted the largest percentage increases.

PNM Resources, headquartered in Albuquerque, New Mexico, raised its quarterly dividend from $0.3275 to $0.3475 and then to $0.3575 per share. The increases are consistent with the company's target to pay out 55% of annual ongoing earnings. CenterPoint Energy, based in Houston, Texas, increased its quarterly dividend from $0.17 to $0.18 and then to $0.19 per share. The increases align the company for an annual dividend growth rate of 9% in 2023 when compared to dividends paid in 2022. NextEra Energy,

## 2022 Dividend Patterns

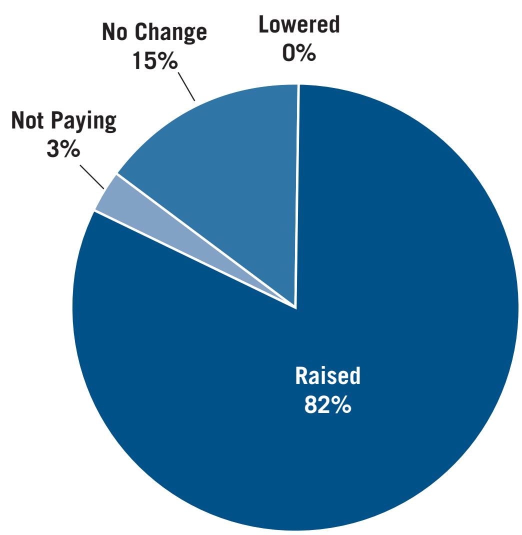
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department.

## 2021 Dividend Patterns

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department.

based in Juno Beach, Florida, increased its quarterly dividend from $0.385 to $0.425 per share. The increase is consistent with its plan, announced in 2020, to target roughly 10% annual growth in dividends per share through at least 2022, off a 2020 base. NextEra recorded the industry's highest percentage increases in 2021 (+10.0%), 2020 (+12.0%) and 2019 (+12.6%), which followed the second-highest percentage increase in 2018 (+13.0%) and the largest percentage increases in both 2017 (+12.9%) and 2016 (+13.0%, along with Edison International and DTE Energy).

PPL reduced its quarterly dividend from $0.415 to $0.20 in Q1 as part of a strategic repositioning and dividend reset. The company completed a targeted $1 billion share repurchase program on December 31, 2021, which returned value to existing shareholders in a different manner than dividends. During 2022, PPL completed the sale of its U.K. business (Western Power Distribution) and purchased Narragansett Electric Company, which is Rhode Island's primary electric and gas utility. PPL subsequently increased its dividend by 12.5% during Q2 2022 to a quarterly rate of $0.225 per share.

The industry's average and median increases have been relatively consistent in recent years. The average was 4.8% in 2021 and ranged between 5.1% and 5.7% from 2016 through 2020. The median increase was 5.4% in 2021 and ranged between 4.9% and 5.5% from 2017 through 2020.

### Payout Ratio and Dividend Yield

The industry's dividend payout ratio was 73.0% for the twelve months ended December 31, 2022, exceeding all other U.S. business sectors. The industry's payout ratio was 70.8% when measured as an un-weighted average of individual company ratios; 73.0% represents an aggregate figure. From 2000 through 2021, the industry's annual payout ratio ranged from 60.4% to 69.6%.

While the industry's net income has fluctuated from year to year, its payout ratio has remained relatively consistent after eliminating non-recurring and extraordinary items from earnings. We use the following approach when calculating the industry's dividend payout ratio:

1. Non-recurring and extraordinary items are eliminated from earnings.
2. Companies with negative adjusted earnings are eliminated.

## Sector Comparison Dividend Payout Ratio

**For 12-month period ending 12/31/22**

| Sector | Payout Ratio (%) |
|---|---|
| **EEI Index Companies*** | **73.0%** |
| Utilities | 59.3% |
| Consumer Staples | 54.3% |
| Industrial | 34.5% |
| Financial | 29.1% |
| Materials | 29.0% |
| Consumer Discretionary | 27.6% |
| Energy | 26.7% |
| Health Care | 26.1% |
| Technology | 23.0% |

* For this table, EEI (1) sums dividends and (2) sums earnings of all index companies and then (3) divides to determine the comparable DPR.

**Assumptions:**

1. EEI Index Companies payout ratio based on LTM common dividends paid and income before nonrecurring and extraordinary items.

2. S&P sector payout ratios based on 2022E dividends and earnings per share (estimates as of 12/31/2022).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence, and EEI Finance Department.

## Sector Comparison, Dividend Yield

### As of December 31, 2022

| Sector | Dividend Yield (%) |
|---|---|
| **EEI Index Companies** | **3.4%** |
| Energy | 3.2% |
| Utilities | 3.0% |
| Consumer Staples | 2.5% |
| Financial | 2.1% |
| Materials | 2.1% |
| Industrial | 1.7% |
| Health Care | 1.6% |
| Technology | 1.1% |
| Consumer Discretionary | 1.0% |

**Assumptions:**
1. EEI Index Companies' yield based on last announced, annualized dividend rates (as of 12/31/2022); S&P sector yields based on 2022E cash dividends (estimates as of 12/31/2022).

For more information on constituents of each S&P sector, see http://www.sectorspdr.com/.

Source: AltaVista Research, S&P Global Market Intelligence and EEI Finance Department.

3. Companies with a payout ratio in excess of 200% are eliminated.

The industry's average dividend yield was 3.4% on December 31, 2022, leading all U.S. business sectors. The yield reached 3.8% on June 30, 2020 and has since fallen due to a rise in utility stock prices and consistent dividend activity. The market cap weighted EEI Index had a total return of 1.2% in 2022. The industry's year-end dividend yield was 3.3% in 2021, 3.6% in 2020, 3.0% in 2019 and 3.4% in each of the three previous years.

We calculate the industry's average dividend yield using an un-weighted average of the yields of EEI Index companies paying a dividend. The strong yields prevalent among most electric utilities have helped support their share prices over the past decade, particularly given the period's historically low interest rates.

### Business Category Comparison

The Regulated category's dividend payout ratio was 69.2% for the 12 months ended December 31, 2022, compared to 77.4% for the Mostly Regulated category. The Regulated group produced the higher annual payout ratio in 2020, 2017, 2015, 2011, 2010 and in each year from 2003 through 2008.

The Regulated and Mostly Regulated average dividend yields were 3.4% and 3.3% on December 31, 2022, compared to 3.3% and 3.0% at year-end 2021, 3.6% and 3.4% at year-end 2020 and 3.0 and 3.1% at year-end 2019. The dividend yields for both categories at year-end 2018 and 2017 were 3.4%.

### Electric Utilities' History of Strong Dividends

For more than a century, the investor-owned electric utility industry has stood out among U.S. business sectors for its steady and rising dividends. This reputation is founded on:

- A steady stream of income from a product that is universally needed with low elasticity of demand.
- A highly regulated industry that provides reasonable returns on investment with associated low business risk.
- A mature industry comprised of companies with very long track records of maintaining and/or steadily increasing their dividends over time.

These characteristics are especially attractive to an aging population of investors who seek a combination of growth and income. A typical total return model for electric utilities is approximately 4-5% annual earnings growth and a 3-4% dividend yield, producing a highly visible and relatively stable 7-9% annualized long-term total return potential.

## Category Comparison, Dividend Payout Ratio

| Category | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **EEI Index** | **61.5** | **60.4** | **67.0** | **62.9** | **64.0** | **63.9** | **62.6** | **65.3** | **61.6** | **70.8** |
| Regulated | 60.5 | 59.4 | 68.7 | 61.1 | 68.7 | 60.1 | 62.1 | 65.3 | 59.5 | 69.2 |
| Mostly Regulated | 64.7 | 63.8 | 62.6 | 68.0 | 53.3 | 72.8 | 64.1 | 65.2 | 69.0 | 77.4 |
| Diversified | 44.7 | 56.4 | 64.9 | 64.6 | – | – | – | – | – | – |

Regulated: 80% or more of total assets are regulated
Mostly Regulated: Less than 80% of total assets are regulated
Diversified: Prior to 2017, less than 50% of total assets are regulated

*2022 figures reflect earnings and dividends through 12/31/2022.

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department

## Category Comparison, Dividend Yield
### As of December 31, 2022

| Category | Dividend Yield |
|---|---|
| **EEI Index** | **3.4%** |
| Regulated | 3.4% |
| Mostly Regulated | 3.3% |

**Regulated:** 80% or more of total assets are regulated
**Mostly Regulated:** Less than 80% of total assets are regulated
Source: S&P Global Market Intelligence, company reports and EEI Finance Department

The market's valuation of that return stream, of course, will shift with investor sentiment.

### IRA Brings No Change to Dividend Tax Rate

An increase in dividend tax rates for the highest individual tax bracket was considered a potential revenue source for the Biden Administration's Build Back Better Act (BBBA) legislation until BBBA evolved into the passage of the Inflation Reduction Act of 2022 (IRA) in August. Due to the need to significantly reduce the size of this legislation in order to have a chance at success, the IRA passed as a slimmed down version of BBBA, retaining its robust clean energy tax package while maintaining current capital gains and dividend tax parity.

The top tax rate for dividends and capital gains is currently 20%, applying to 2022 income thresholds of $517,200 for couples and $459,750 for individuals. For taxpayers below these thresholds, dividends and capital gains are currently taxed at rates of 15% or 0%, depending on a filer's income. A 3.8% Medicare tax that was included in 2010 health care legislation is also applied to all investment income for couples earning more than $250,000 ($200,000 for singles).

Low dividend tax rates support the industry's ability to attract capital for investment. Maintaining parity between dividend and capital gains tax rates is crucial to avoid a disadvantage for companies that rely on a strong dividend to attract investors.

## Dividend Summary

### As of December 31, 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Company Name | Stock | Company Category | Annualized Dividends | Payout Ratio | Yield (%) | Last Action | To | From | Date Announced |
|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | MR | $2.60 | 111.1% | 4.0% | Raised | $2.60 | $2.52 | 2022 Q1 |
| Alliant Energy Corporation | LNT | R | $1.71 | 62.5% | 3.1% | Raised | $1.71 | $1.61 | 2022 Q1 |
| Ameren Corporation | AEE | R | $2.36 | 56.5% | 2.7% | Raised | $2.36 | $2.20 | 2022 Q1 |
| American Electric Power Company, Inc. | AEP | R | $3.32 | 67.3% | 3.5% | Raised | $3.32 | $3.12 | 2022 Q4 |
| AVANGRID, Inc. | AGR | MR | $1.76 | 81.9% | 4.1% | Raised | $1.76 | $1.73 | 2018 Q3 |
| Avista Corporation | AVA | R | $1.76 | 83.2% | 4.0% | Raised | $1.76 | $1.69 | 2022 Q1 |
| Black Hills Corporation | BKH | R | $2.50 | 57.9% | 3.6% | Raised | $2.50 | $2.38 | 2022 Q4 |
| CenterPoint Energy, Inc. | CNP | R | $0.76 | NM | 2.5% | Raised | $0.76 | $0.72 | 2022 Q4 |
| CMS Energy Corporation | CMS | R | $1.84 | 66.0% | 2.9% | Raised | $1.84 | $1.74 | 2022 Q1 |
| Consolidated Edison, Inc. | ED | R | $3.16 | 59.4% | 3.3% | Raised | $3.16 | $3.10 | 2022 Q1 |
| Dominion Resources, Inc. | D | R | $2.67 | 96.6% | 4.4% | Raised | $2.67 | $2.52 | 2022 Q1 |
| DTE Energy Company | DTE | R | $3.81 | 66.8% | 3.2% | Raised | $3.81 | $3.54 | 2022 Q4 |
| Duke Energy Corporation | DUK | R | $4.02 | 78.4% | 3.9% | Raised | $4.02 | $3.94 | 2022 Q3 |
| Edison International | EIX | R | $2.95 | 43.6% | 4.6% | Raised | $2.95 | $2.80 | 2022 Q4 |
| Entergy Corporation | ETR | R | $4.28 | 98.8% | 3.8% | Raised | $4.28 | $4.04 | 2022 Q4 |
| Evergy, Inc. | EVRG | R | $2.45 | 69.3% | 3.9% | Raised | $2.45 | $2.29 | 2022 Q4 |
| Eversource Energy | ES | R | $2.55 | 60.2% | 3.0% | Raised | $2.55 | $2.41 | 2022 Q1 |
| Exelon Corporation | EXC | MR | $1.35 | 61.7% | 3.1% | Raised | $1.35 | N/A | 2020 Q1 |
| FirstEnergy Corp. | FE | R | $1.56 | 149.5% | 3.7% | Raised | $1.56 | $1.52 | 2019 Q4 |
| Hawaiian Electric Industries, Inc. | HE | MR | $1.40 | 65.2% | 3.3% | Raised | $1.40 | $1.36 | 2022 Q1 |
| IDACORP, Inc. | IDA | R | $3.16 | 59.4% | 2.9% | Raised | $3.16 | $3.00 | 2022 Q4 |
| MDU Resources Group, Inc. | MDU | MR | $0.89 | 48.2% | 2.9% | Raised | $0.89 | $0.87 | 2022 Q4 |
| MGE Energy, Inc. | MGEE | R | $1.63 | 51.8% | 2.3% | Raised | $1.63 | $1.55 | 2022 Q3 |
| NextEra Energy, Inc. | NEE | MR | $1.70 | 98.6% | 2.0% | Raised | $1.70 | $1.54 | 2022 Q1 |
| NiSource Inc. | NI | R | $0.94 | 55.5% | 3.4% | Raised | $0.94 | $0.88 | 2022 Q1 |
| NorthWestern Corporation | NWE | R | $2.52 | 76.5% | 4.2% | Raised | $2.52 | $2.48 | 2022 Q1 |
| OGE Energy Corp. | OGE | R | $1.66 | NM | 4.2% | Raised | $1.66 | $1.64 | 2022 Q3 |
| Otter Tail Corporation | OTTR | R | $1.65 | 24.2% | 2.8% | Raised | $1.65 | $1.56 | 2022 Q1 |
| PG&E Corporation | PCG | R | $- | 0.0% | 0.0% | Lowered | $- | $2.12 | 2017 Q4 |
| Pinnacle West Capital Corporation | PNW | R | $3.46 | 75.7% | 4.6% | Raised | $3.46 | $3.40 | 2022 Q4 |
| PNM Resources, Inc. | PNM | R | $1.47 | 62.1% | 3.0% | Raised | $1.47 | $1.39 | 2022 Q4 |
| Portland General Electric Company | POR | R | $1.81 | 67.8% | 3.7% | Raised | $1.81 | $1.72 | 2022 Q2 |
| PPL Corporation | PPL | R | $0.90 | 110.2% | 3.1% | Raised | $0.90 | $0.80 | 2022 Q2 |
| Public Service Enterprise Group Incorporated | PEG | MR | $2.16 | 74.9% | 3.5% | Raised | $2.16 | $2.04 | 2022 Q1 |
| Sempra Energy | SRE | R | $4.58 | 56.5% | 3.0% | Raised | $4.58 | $4.40 | 2022 Q1 |
| Southern Company | SO | R | $2.72 | 68.0% | 3.8% | Raised | $2.72 | $2.64 | 2022 Q2 |
| Unitil Corporation | UTL | R | $1.56 | 60.6% | 3.0% | Raised | $1.56 | $1.52 | 2022 Q1 |
| WEC Energy Group, Inc. | WEC | R | $2.91 | 63.5% | 3.1% | Raised | $2.91 | $2.71 | 2022 Q1 |
| Xcel Energy Inc. | XEL | R | $1.95 | 58.3% | 2.8% | Raised | $1.95 | $1.83 | 2022 Q1 |
| **Industry Average** | | | | **70.8%** | **3.4%** | | | | |

NOTES
Business Segmentation: Assets as of 12/31/2021
**R = Regulated:** 80% or more of total assets are regulated. **MR = Mostly Regulated:** Less than 80% of total assets are regulated.

Dividend Per Share: Per share amounts are annualized declared figures as of 12/31/2022.
Dividend Payout Ratio: Dividends paid for 12 months ended 12/31/2022 divided by net income before nonrecurring and extraordinary items for 12 months ended 12/31/2022. While net income is after-tax, nonrecurring and extraordinary items are pre-tax, as there is no consistent method of gathering these items on a tax adjusted basis under current reporting guidelines. On an individual company basis, the Payout Ratio in the table could differ slightly from what is reported directly by the company.
"NM" applies to companies with negative earnings or payout ratios greater than 200%.
Dividend Yield: Annualized Dividends Per Share at 12/31/2022 divided by stock price at market close on 12/31/2022.
By Business Segment: Average of Dividend Payout Ratios and Dividend Yields for companies within these business segments.

Source: EEI Finance Department and S&P Global Market Intelligence.

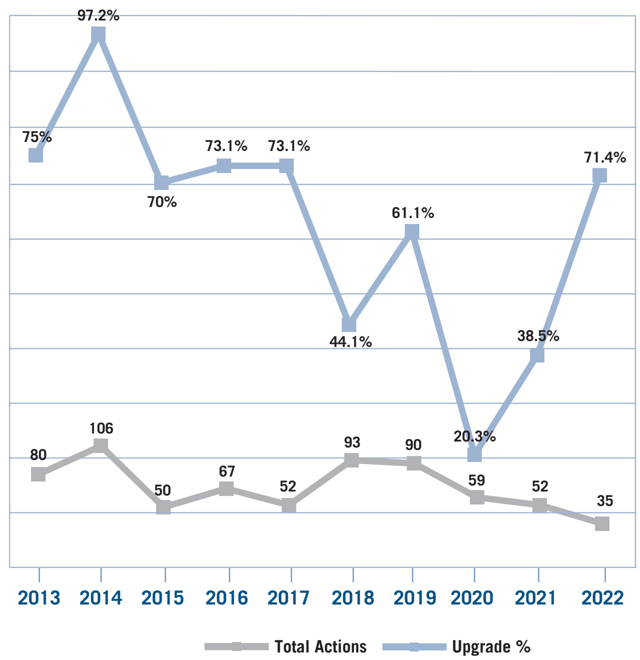
## Credit Ratings

The industry's average parent company credit rating in 2022 remained at BBB+ for the ninth straight year, although one parent-level downgrade caused a slight weakening in aggregate holding company credit quality. There were only 35 total actions — 25 upgrades and 10 downgrades — affecting both parents and subsidiaries. This pace was far below the 73-action annual average of the previous ten calendar years and is the lowest annual total in our historical dataset (back to 2000).

On December 31, 2022, 77.3% of parent company ratings outlooks were "stable", 9.1% were "positive" or "watch-positive", and 2.3% were "developing". Only 11.4% of outlooks were "negative" or "watch-negative"; that was down from 22.7% at year-end 2021.

## Direction of Rating Actions

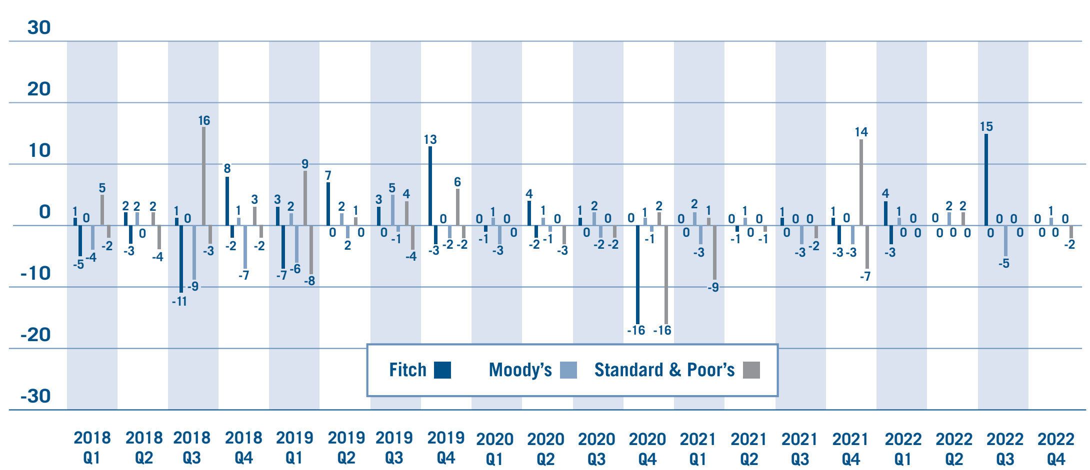
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: Fitch Ratings, Moody's, and Standard & Poor's.

## Credit Rating Agency Upgrades and Downgrades 2018 Q1–2022 Q4

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Note: Data presents the number of occurrences and includes each event, even if multiple actions occurred for a single company.

Source: Fitch Ratings, Moody's, and Standard & Poor's.

## Credit Rating Agency Upgrades and Downgrades 2018 Q1–2022 Q4

| | 2018 | | 2019 | | 2020 | | 2021 | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total Upgrades | Total Downgrades | Total Upgrades | Total Downgrades | Total Upgrades | Total Downgrades | Total Upgrades | Total Downgrades | Total Upgrades | Total Downgrades |
| **Fitch** | | | | | | | | | | |
| **Q1** | 1 | (5) | 3 | (7) | 0 | (1) | 0 | 0 | 4 | (3) |
| **Q2** | 2 | (3) | 7 | 0 | 4 | (2) | 0 | (1) | 0 | 0 |
| **Q3** | 1 | (11) | 3 | 0 | 1 | 0 | 1 | 0 | 15 | 0 |
| **Q4** | 8 | (2) | 13 | (3) | 0 | (16) | 1 | (3) | 0 | 0 |
| **Total** | **12** | **(21)** | **26** | **(10)** | **5** | **(19)** | **2** | **(4)** | **19** | **(3)** |
| **Moody's** | | | | | | | | | | |
| **Q1** | 0 | (4) | 2 | (6) | 1 | (3) | 2 | (3) | 1 | 0 |
| **Q2** | 2 | 0 | 2 | (2) | 1 | (1) | 1 | 0 | 2 | 0 |
| **Q3** | 0 | (9) | 5 | (1) | 2 | (2) | 0 | (3) | 0 | (5) |
| **Q4** | 1 | (7) | 0 | (2) | 1 | (1) | 0 | (3) | 1 | 0 |
| **Total** | **3** | **(20)** | **9** | **(11)** | **5** | **(7)** | **3** | **(9)** | **4** | **(5)** |
| **S&P** | | | | | | | | | | |
| **Q1** | 5 | (2) | 9 | (8) | 0 | 0 | 1 | (9) | 0 | 0 |
| **Q2** | 2 | (4) | 1 | 0 | 0 | (3) | 0 | (1) | 2 | 0 |
| **Q3** | 16 | (3) | 4 | (4) | 0 | (2) | 0 | (2) | 0 | 0 |
| **Q4** | 7 | 0 | 3 | (2) | 2 | (16) | 14 | (7) | 0 | (2) |
| **Total** | **17** | **(8)** | **26** | **(11)** | **2** | **(21)** | **15** | **(19)** | **2** | **(2)** |

Note: Chart depicts the number of occurrences and includes each event, even if multiple downgrades occurred for a single company.
Source: Fitch Ratings, Moody's, and Standard & Poor's.

Electric utility industry credit quality generally improved over the past decade. The industry's average parent level rating has held at BBB+ since increasing from BBB in 2014. A closer look at the underlying calculation of this average shows a steady strengthening from 2013 through 2018, followed by a slight decline in 2019, 2020, 2021, and 2022. Across the larger universe that includes both parents and subsidiaries, the five-year period 2013 through 2017, along with 2022, produced the six highest upgrade percentages in our 23 years of historical data. Moreover, upgrades outnumbered downgrades in seven of the past ten calendar years with an annual average upgrade percentage of 62% over the decade.

EEI captures upgrades and downgrades at both the parent and subsidiary levels. The industry's average credit rating and outlook are the unweighted averages of all Standard & Poor's (S&P) parent holding company ratings and outlooks. However, our upgrade/downgrade totals reflect all actions by the three major ratings agencies including both parent holding companies as well as individual subsidiaries. Our universe of 44 U.S. parent company electric utilities on December 31, 2022 included 39 that are publicly traded and 5 that are either a subsidiary of an independent power producer, a subsidiary of a foreign owned company, or owned by an investment firm.

The three major rating agencies stressed similar themes in their outlooks for 2023. S&P maintained a negative outlook, Moody's revised its U.S. regulated utility outlook to negative from stable, and Fitch revised its North American utilities outlook to deteriorating from neutral. All three agencies cited higher natural gas prices, inflation, rising interest rates, and increased capital spending as key concerns. While the agencies noted regulatory relations are broadly constructive, all said that utilities' efforts to manage the regulatory risk associated with residential customer affordability issues will be a key area of scrutiny.

### Credit Actions at Parent Level

Parent-level ratings actions in 2022 by S&P included only one downgrade. By comparison, there were three downgrades and one upgrade in 2021, three downgrades, one upgrade and one reinstatement in 2020, and five downgrades and one upgrade in 2019.

### *DPL*

On December 21, S&P downgraded DPL Inc. and subsidiary Dayton Power and Light (DP&L) to BB from BB+. Dayton Power & Light received an order from the Public Utilities Commission of Ohio (PUCO) that authorized it to increase its distribution rates by $75 million. However, the increase will not go into effect until the company has a new Electric Security Plan (ESP) in place, which is not anticipated until mid-2023. S&P said the companies may be adversely impacted by cash flow pressures due to the delay.

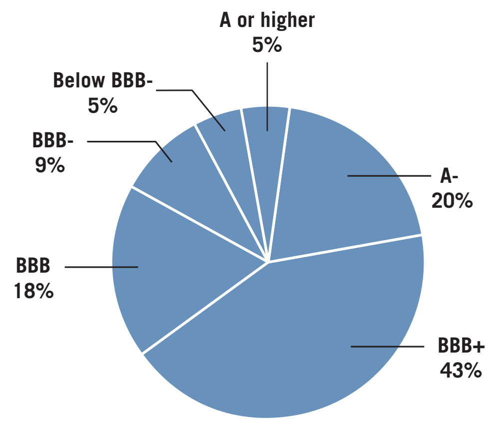
### Ratings Activity Remained Slow in 2022

The 35 rating changes during 2022 (upgrades plus downgrades), 17 fewer than in 2021, was the lowest total of any year back to our dataset's inception in 2000. By comparison, there were 59 actions in 2020, 90 in 2019, and an annual average of 73 over the previous decade.

The industry's 25 upgrades in 2022 versus 10 downgrades produced an upgrade percentage of 71.4%, up from 38.5% in 2021 and 20.3% in 2020. Upgrades outnumbered downgrades in seven of the past ten calendar years, with an annual average upgrade percentage of 62%.

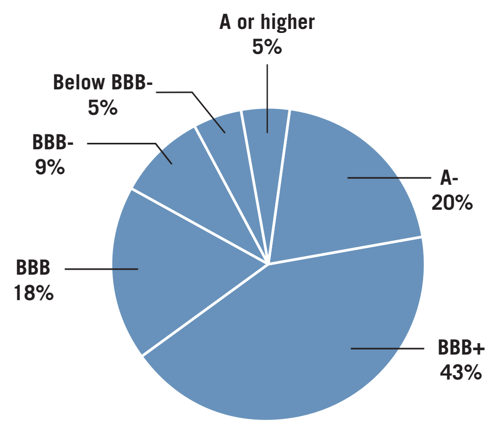
## Bond Ratings December 31, 2022
### as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



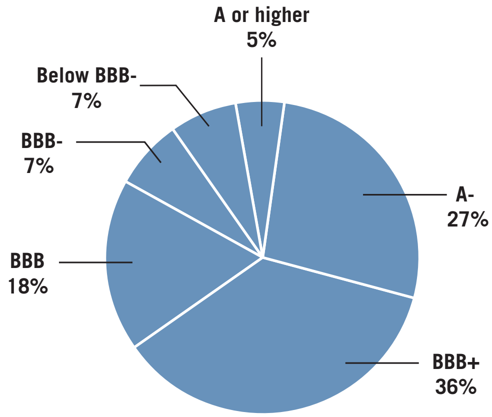

## Bond Ratings December 31, 2021
### as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



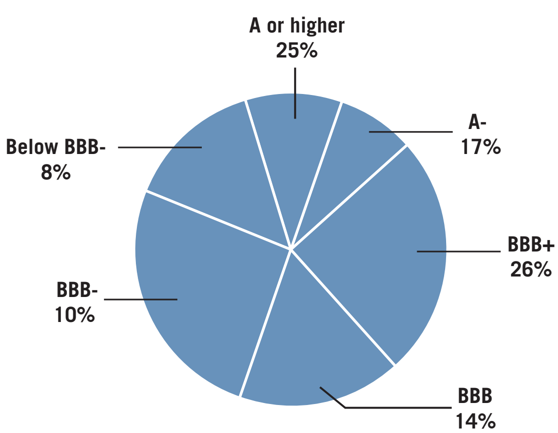
## Bond Ratings December 31, 2020
### as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




## Bond Ratings December 31, 2001
### as rated by Standard & Poor's

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




The Credit Rating Agency Upgrades and Downgrades table presents quarterly activity by all three ratings agencies. Following are full-year totals for 2022:

- Fitch (19 upgrades, 3 downgrades)
- Moody's (4 upgrades, 5 downgrades)
- Standard & Poor's (2 upgrades, 2 downgrades)

### Upgrades in 2022

Many of the year's upgrades came after favorable regulatory outcomes or strengthened financial metrics under new ownership. Upgrades were also driven by the use of asset sale proceeds to reduce parent company debt.

On January 14, Fitch upgraded Pepco Holdings, Pepco, and Atlantic City Electric to BBB+ from BBB due to improved credit profiles from supportive regulatory decisions.

On January 28, Moody's upgraded Entergy Texas to Baa2 from Baa3, following improved legislative and regulatory support. Moody's cited as reasons for the upgrade a recent authorization to securitize $250 million of storm costs, expedited cost recovery for a combined-cycle plant that recently began operations, and an upcoming rate case proceeding.

On March 30, Fitch upgraded Public Service Company of North Carolina (PSNC) to A- from BBB+ citing its strengthened financial condition as a result of equity contributions under Dominion's ownership since 2019 and a favorable re-

## Rating Agency Activity

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Total Ratings Changes | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| Fitch | 23 | 14 | 11 | 16 | 15 | 33 | 36 | 24 | 6 | 22 |
| Moody's | 17 | 85 | 12 | 13 | 12 | 23 | 20 | 12 | 12 | 9 |
| Standard & Poor's | 40 | 7 | 27 | 38 | 25 | 37 | 34 | 23 | 34 | 4 |
| **Total** | **80** | **106** | **50** | **67** | **52** | **93** | **90** | **59** | **52** | **35** |

Source: Fitch Ratings, Moody's, Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

cent rate case outcome. The North Carolina commission approved a settlement with an ROE of 9.6% and equity capitalization of 51.6%. This was the first PSNC rate case under Dominion ownership. Fitch also cited strong service territory customer growth that support improved credit metrics.

On May 27, S&P upgraded PPL Electric Utilities (PPLEU), the Pennsylvania transmission and distribution subsidiary of PPL, to A from A-. The upgrade reflects S&P's view that PPLEU's financial performance, funding arrangements and operational independence are sufficient to support this rating.

On June 2, S&P Global Ratings raised the issuer credit rating of Narragansett Electric Co. (NECO) by one notch to A-. S&P cited the resolution of legal issues in Rhode Island that cleared the way for PPL to finalize its acquisition of Narragansett Electric. S&P assessed NECO's business risk profile as excellent due to supportive regulatory mechanisms in Rhode Island as well as electric transmission assets that benefit from a very supportive FERC regulatory framework.

On June 6, Moody's upgraded PPL Corporation to Baa1 from Baa2, based on its improved business risk profile; PPL reduced parent company debt by $3.5 billion using proceeds from the sale in 2021 of its U.K. utility business, Western Power Distribution, to National Grid for net cash proceeds of $10.4 billion. Moody's stable outlook reflects PPL's new business mix with its four U.S. utilities all operating in supportive regulatory environments. Moody's also upgraded Narragansett Electric Company to A3 from Baa1.

On July 22, Fitch upgraded FirstEnergy (FE) to BBB from BB+ based on FE's completed sale in May 2022 of a 20% ownership interest in FirstEnergy Transmission for $2.4 billion, FE's issuance of $1 billion of new equity, and a regulatory settlement in Ohio that provide rate certainty through May 2024. FirstEnergy used proceeds from its asset sales and equity issuance to pay down $2.4 billion of parent company debt. Fitch also raised the rating for fourteen subsidiaries.

On December 15, Moody's upgraded Dominion Energy South Carolina (DESC) to Baa1 from Baa2. The upgrade followed a series of rate orders by the South Carolina Public Service Commission (SCPSC) in 2022 that will help DESC recover higher costs, including under-recovered fuel balances, and improve cash flow. The SCPSC approved a settlement in December between DESC and various intervenors that provides $167 million of additional revenue to improve DESC's fuel cost recovery.

### Downgrades in 2022

Many downgrades focused on increased debt and cash flow pressures that impacted credit metrics. The slow recovery of planned capital expenditures also drove several downgrades. Project delays related to a large nuclear project were cited also.

On January 14, Fitch downgraded Exelon to BBB from BBB+ due to higher leverage after the company's separation from its unregulated generation subsidiary, despite a resulting improved risk profile. Fitch observed that an expected equity issuance will not offset the loss of cash from the generation subsidiary and will result in increased parent debt.

On February 22, Fitch downgraded Georgia Power Company to BBB from BBB+ following an announced three- to six-month delay of the projected in-service dates for Vogtle nuclear units 3 and 4. The downgrade reflects continued uncertainty regarding the completion schedule and remaining costs for these nuclear generating facilities, with Georgia Power bearing a larger portion of cost increases under a 2018 modified co-owner agreement.

On March 24, Fitch downgraded NorthWestern Corporation to BBB from BBB+, primarily due to weaker credit metrics from expected regulatory lag during a period of extensive capital expenditures. The company's credit metrics are being pressured by a challenging regulatory framework, which is largely backward-looking, and a series of unfavorable rulings by the Montana commission that deny or delay recovery of expenses.

On July 6, Moody's downgraded IDACORP to Baa2 from Baa1 and subsidiary Idaho Power Company (IPC) to Baa1 from A3. Approximately 90% of IDACORP's cash flow is generated by IPC. Moody's observed that credit metrics would improve with more timely rate relief through riders or cost tracking mechanisms, quicker asset recovery via depreciation rates, and more frequent rate case filings. IPC's last rate increase under a general rate review occurred in 2011.

On August 22, Moody's downgraded AEP subsidiary Ohio Power Company to Baa1 from A3. Moody's cited weakened credit metrics from increased debt used to finance Ohio Power's significant investments in transmission and distribution infrastructure. Ohio Power's cash flow has also been negatively impacted by the expiration of legacy riders associated with the transition to competition in Ohio.

On September 13, Moody's downgraded the ratings of First Energy subsidiaries Cleveland Electric Illuminating Company (to Baa3 from Baa2) and Toledo Edison (to Baa2 from Baa1). Moody's said the companies will be adversely impacted by cash flow pressures caused by customer refunds stipulated in a 2021 regulatory settlement in Ohio. Both companies are expected to file rate cases by May 2024, when their current Electric Security Plans (ESP) expire.

### Ratings by Company Category

The S&P Utility Credit Ratings Distribution by Company Category chart presents the distribution of credit ratings over time by company category (Regulated, Mostly Regulated and Diversified) for the investor-owned electric utilities. The Diversified category was eliminated in 2017 due to its dwindling number of companies. Ratings are based on S&P's long-term issuer ratings at the holding company level, with only one rating assigned per company. On December 31, 2022, the average rating for both the Regulated and Mostly Regulated categories was BBB+.

### Rating Agency Credit Outlooks

The three major ratings agencies held similar utility industry credit outlooks as 2023 began. S&P maintained a negative outlook, Moody's revised its U.S. regulated utility outlook to negative from stable, and Fitch revised its North American utilities outlook to deteriorating from neutral. The agencies cited inflation, rising interest rates and higher natural gas prices and related customer bill impacts as key themes they are watching. It should be noted that the groups of underlying companies vary slightly across the three agency outlooks.

***Standard & Poors (S&P)***

Published in late January 2023, S&P's report "Industry Top Trends 2023 – North America Regulated Utilities" maintained the agency's negative industry outlook. The report noted that downgrades outpaced upgrades for the third consecutive year. While the percentage of negative outlooks decreased to 12% from 20% at year-end 2021, S&P stated that prolonged inflation or a deeper-than-expected recession could harm the industry's credit quality in 2023. Only 7% of the industry had a positive outlook.

S&P's base case assumes inflation will moderate during 2023 and the industry's credit measures will generally remain stable. However, persistent inflation could put additional pressure on customer bills and decrease regulatory support.

The report also cited potential risks related to the industry's aggressive reduction of greenhouse gas (GHG) emissions. S&P noted industry capital spending in 2022 reached an all-time high with an even higher total expected in 2023 with future investment focused on renewables and related infrastructure. As bills increase, regulators may

## S&P Utility Credit Ratings Distribution by Company Category

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| | 2018 | | 2019 | | 2020 | | 2021 | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | # | % | # | % | # | % | # | % | # | % |
| **Regulated** | | | | | | | | | | |
| A or higher | 1 | 3% | 1 | 3% | 1 | 3% | 1 | 3% | 1 | 3% |
| A- | 11 | 32% | 11 | 31% | 11 | 32% | 8 | 23% | 8 | 22% |
| BBB+ | 11 | 32% | 11 | 31% | 10 | 29% | 14 | 40% | 15 | 42% |
| BBB | 7 | 21% | 8 | 23% | 7 | 21% | 7 | 20% | 7 | 19% |
| BBB- | 4 | 12% | 2 | 6% | 2 | 6% | 3 | 9% | 3 | 8% |
| Below BBB- | 0 | 0% | 2 | 6% | 3 | 9% | 2 | 6% | 2 | 6% |
| **Total** | 34 | 100% | 35 | 100% | 34 | 100% | 35 | 100% | 36 | 100% |
| **Mostly Regulated** | | | | | | | | | | |
| A or higher | 2 | 15% | 1 | 10% | 1 | 10% | 1 | 11% | 1 | 13% |
| A- | 2 | 15% | 1 | 10% | 1 | 10% | 1 | 11% | 1 | 13% |
| BBB+ | 7 | 54% | 7 | 70% | 6 | 60% | 5 | 56% | 4 | 50% |
| BBB | 1 | 8% | 0 | 0% | 1 | 10% | 1 | 11% | 1 | 13% |
| BBB- | 1 | 8% | 1 | 10% | 1 | 10% | 1 | 11% | 1 | 13% |
| Below BBB-0 | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% | 0 | 0% |
| **Total** | 13 | 100% | 10 | 100% | 10 | 100% | 9 | 100% | 8 | 100% |

Note: Totals may not equal 100.0% due to rounding.
Refer to page v for category descriptions.
Source: Standard & Poor's, S&P Global Market Intelligence, and EEI Finance Department.

ask the industry to slow the pace of the energy transition, possibly delaying the achievement of net-zero carbon emissions. In addition, large renewable projects (such as offshore wind) could become more challenging as timelines and budgets are affected by supply chain delays and rising interest rates. While much of the S&P report focused on the increased regulatory scrutiny that often accompanies higher customer bills, it also noted the average electric bill represents only about 2.5% of after-tax household income.

### *Moody's*

In its "2023 Outlook – Regulated Electric and Gas Utilities – US" (released November 2022), Moody's revised its outlook for the sector to negative from stable. The report cited risks related to inflation, rising interest rates and higher natural gas prices as areas of concern. These developments could lead to customer affordability challenges and increased uncertainty related to the timely recovery of fuel and purchased power costs. The report also stated that capital spending and dividends will likely be sustained at a steady rate, possibly weighing on near-term credit metrics. The sector's aggregate industry funds from operations (FFO) to debt ratio will likely be 14% in 2023, according to the report, but may fall below this level if cost recovery is delayed.

Moody's listed several factors that could change its outlook back to stable: 1) if the sector's regulatory support remains intact, 2) if natural gas prices settle at a level that allows most utilities to fully recover fuel and purchased power costs within 12 months, 3) if inflation moderates and interest rates stabilize, and

## Long-Term Credit Rating Scales

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|
| Investment Grade | Aaa | AAA | AAA |
| | Aa1 | AA+ | AA+ |
| | Aa2 | AA | AA |
| | Aa3 | AA- | AA- |
| | A1 | A+ | A+ |
| | A2 | A | A |
| | A3 | A- | A- |
| | Baa1 | BBB+ | BBB+ |
| | Baa2 | BBB | BBB |
| | Baa3 | BBB- | BBB- |

| | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|
| Speculative Grade | Ba1 | BB+ | BB+ |
| | Ba2 | BB | BB |
| | Ba3 | BB- | BB- |
| | B1 | B+ | B+ |
| | B2 | B | B |
| | B3 | B- | B- |
| | Caa1 | CCC+ | CCC+ |
| | Caa2 | CCC | CCC |
| | Caa3 | CCC- | CCC- |
| | Ca | CC | CC |
| | C | C | C |

| | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|
| Default | C | D | D |

Source: Fitch Ratings, Moody's, and Standard & Poor's.

4) if the sector's aggregate FFO-to-debt ratio remains between 14% and 15%. Factors that could change its outlook to positive were: 1) if utility regulation turns broadly more credit supportive resulting in quicker cash flow recovery, and 2) if the sector's aggregate FFO-to-debt ratio rises above 17% on a sustained basis.

### *Fitch Ratings*

In its "North American Utilities, Power & Gas Outlook 2023" (released December 2022), Fitch Ratings revised its outlook for the sector to deteriorating from neutral. The move primarily reflects growing cost pressures for utilities due to higher commodity prices, inflation, and rising interest rates. These factors, combined with high capital expenditures and storm restoration costs from extreme weather, are driving customer bills higher. Fitch noted that deferred fuel balances are increasing, which may affect credit metrics as utilities try to spread the recovery of these costs over an extended time period to mitigate the impact on customer bills.

The report also noted positive tailwinds that could offset these concerns. Retail electricity sales continue to show resilience and remain above pre-pandemic levels. Fitch expects authorized ROEs to start trending up in reaction to the recent rise in interest rates. Many utilities are increasingly using tools such as securitization for under-recovered fuel balances. The Inflation Reduction Act provides tax incentives for clean generation that may offset inflationary bill pressures. Finally, many companies are using asset monetization, such as the sale of non-regulated renewable businesses and the partial or full sale of regulated subsidiaries, to replace equity needs.

With 88% of companies at a stable ratings outlook, Fitch expects little ratings movement in 2023. The agency noted that higher-than-expected natural gas prices remains the largest risk to credit metrics since increases in deferred fuel balances can impair the timely recovery of capital expenditures.

# Business Strategies

## Business Segmentation

The industry's regulated business segments — regulated electric and natural gas distribution — grew their combined assets by $128.5 billion, or 7.8%, in 2022, extending a multi-year trend and driving a $78.2 billion, or 4.0%, increase in total industry assets. Regulated assets were 84.9% of the industry total at year-end, rising from 81.7% at year-end 2021. The Regulated Electric segment's share of total industry assets increased to 70.9% from 68.6% at year-end 2021 while the segment's total assets grew $98.8 billion, or 7.2%. Natural Gas Distribution assets rose $29.7 billion, or 11.4%, and Competitive Energy assets decreased $47.4 billion, or 22.7%. Assets for the Natural Gas Pipeline segment increased by $2.7 billion, or 8.2%. A record-high $147.7 billion of capital expenditures and generally constructive regulatory relations supported the significant growth in Regulated assets.

The Regulated Electric business segment's revenue increased by $38.3 billion, or 14.1%, as power demand rose 2.8% and inflationary pressures drove up fuel costs. Natural Gas Distribution revenue increased $14.0 billion, or 26.1%. Competitive Energy revenue decreased $14.3 billion, or 30.6%. Natural Gas Pipeline revenue increased by $1.0 billion, or 19.0%. Overall, total industry revenue increased $38.9 billion, or 10.1%, in 2022.

### 2022 Revenue by Segment

Regulated Electric revenue increased by $38.3 billion, or 14.1%, to $309.7 billion from $271.5 billion in 2021. The segment's share of total industry revenue rose to 71.3% from 68.4% in 2021, remaining well above its level at the start of the industry's two-decade-long migration back to a regulated focus (Regulated Electric's share was only 51.9% in 2005).

## Business Segmentation—Revenues

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| ($ Millions) | 2022 | 2021r | Difference | % Change |
|---|---|---|---|---|
| **Regulated Electric** | 309,739 | 271,451 | 38,288 | 14.1% |
| **Competitive Energy** | 32,480 | 46,800 | (14,320) | -30.6% |
| **Natural Gas Distribution** | 67,426 | 53,469 | 13,957 | 26.1% |
| **Natural Gas Pipeline** | 6,518 | 5,478 | 1,040 | 19.0% |
| **Other** | 18,128 | 19,498 | (1,370) | -7.0% |
| **Discontinued Operations** | — | — | — | 0.0% |
| **Eliminations/Reconciling Items** | (9,863) | (11,197) | 1,333 | -11.9% |
| **Total Revenues** | **424,428** | **385,500** | **38,928** | **10.1%** |

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

## Business Segmentation—Assets

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| ($ Millions) | 12/31/2022 | 12/31/2021 | Difference | % Change |
|---|---|---|---|---|
| **Regulated Electric** | 1,476,245 | 1,377,457 | 98,788 | 7.2% |
| **Competitive Energy** | 161,501 | 208,901 | (47,400) | -22.7% |
| **Natural Gas Distribution** | 291,443 | 261,706 | 29,736 | 11.4% |
| **Natural Gas Pipeline** | 35,373 | 32,691 | 2,682 | 8.2% |
| **Other** | 117,515 | 126,527 | (9,012) | -7.1% |
| **Discontinued Operations** | 1 | 1 | - | 0.0% |
| **Eliminations/Reconciling Items** | (63,257) | (66,629) | 3,372 | -5.1% |
| **Total Assets** | **2,018,820** | **1,940,653** | **78,167** | **4.0%** |

r = revised

Note: Difference and percent change columns may reflect rounding. Totals may reflect rounding.

Natural Gas Distribution revenue rose $14.0 billion, or 26.1%, to $67.4 billion from $53.5 billion in 2021. This followed an increase of 18.0% in 2021, a decrease of 3.3% in 2020, and increases of 4.4% in 2019, 3.0% in 2018, 17.6% in 2017 and 8.9% in 2016; the sharp gains in 2016 and 2017 were due in part to the completion in 2016 of four large acquisitions of natural gas distribution businesses.

Total regulated revenue — the sum of the Regulated Electric and Natural Gas Distribution segments — increased by $52.2 billion, or 16.1%, to $377.2 billion in 2022. The industry's focus on regulated operations has driven a steady growth in these business segments' share of industry revenue in recent years. Regulated revenue accounted for 86.8% of total industry revenue in 2022 compared to 81.9% in 2021, totals well above 2005's 65.3% share.

Eliminations and reconciling items are added back to total revenue to arrive at the denominator for the segment percentage calculations shown in the graphs *Revenue Breakdown 2022 and 2021*.

### 2022 Assets by Segment

Regulated Electric assets increased $98.8 billion, or 7.2%, during 2022. The segment's share of total industry assets was 70.9% at year-end, above its 68.6% share at year-end 2021. Natural Gas Distribution assets increased by $29.7 billion, or 11.4%, while Competitive Energy assets decreased by $47.4 billion, or 22.7%. The Natural Gas Pipeline segment's relatively small asset total grew slightly, increasing by $2.7 billion, or 8.2%, to $35.4 billion at year-end 2022 and representing 1.7% of industry assets.

Total regulated assets (Regulated Electric and Natural Gas Distribution) grew $128.5 billion, or 7.8% in 2022, increasing their share of total industry assets to 84.9% at year-end from 81.7% at year-end 2021.

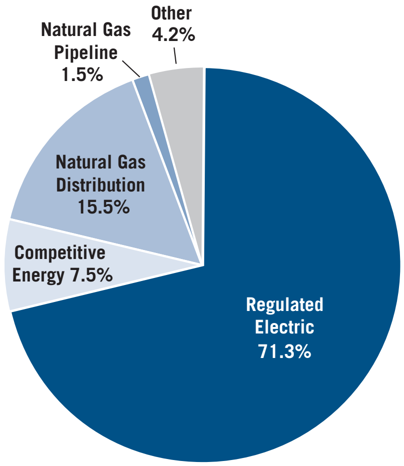
This aggregate measure has risen steadily from 61.6% at year-end 2002, underscoring the significant regulated rate base growth and widespread divestitures of non-core businesses over that 20-year period. Twenty-nine of the industry's 44 constituent companies (66%) either increased regulated assets as a percent of total assets or maintained a 100% regulated structure in 2022.

### Regulated Electric

Regulated Electric segment operations include the generation, transmission and distribution of electricity under state regulation for residential, commercial and industrial custom-

## Revenue Breakdown 2022

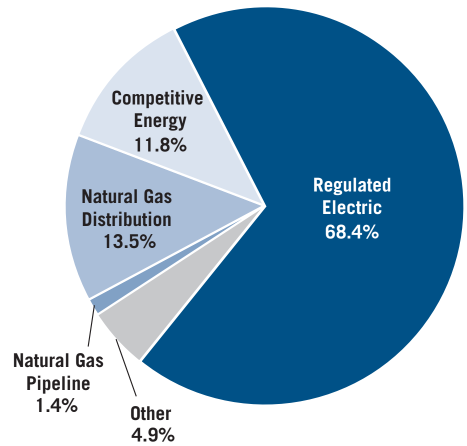
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department and company annual reports.

## Revenue Breakdown 2021r

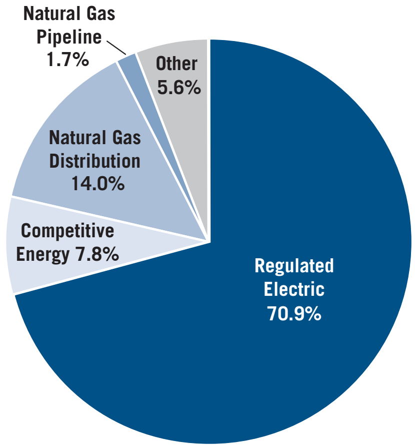
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department and company annual reports.

## Asset Breakdown
### As of December 31, 2022

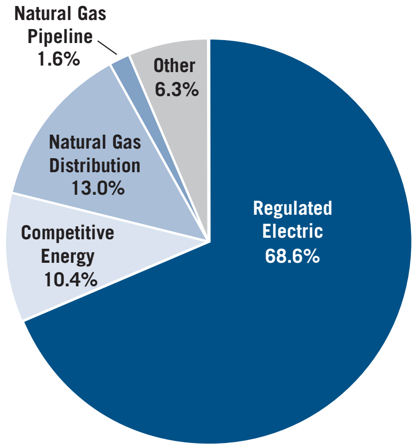
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department and company annual reports.

## Asset Breakdown
### As of December 31, 2021

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department and company annual reports.

ers. Regulated Electric revenue increased significantly in 2022, rising $38.3 billion, or 14.1%. Forty-two companies, or 95% of the industry, had higher Regulated Electric revenue than the prior year. Regulated Electric revenue increased by 8.0% in 2021, fell by 0.8% in 2020 and by 0.5% in 2019, was unchanged in 2018, and grew by 0.8% in 2017.

Total nationwide electric output increased 2.8% in 2022, in line with a 2.8% increase in 2021. On a weather-adjusted basis, electric output rose 1.3% in 2022. Electric output has risen in only eight of the past fifteen years. Prior to this period, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percent demand growth. Energy efficiency initiatives, demand-side management programs, and the off-shoring of formerly U.S.-based manufacturing and heavy industry are all forces that have suppressed the growth of electricity demand since the late 20th century.

Regulated Electric assets increased by $98.8 billion, or 7.2%, in 2022, representing the largest asset growth in dollar terms of all business segments. The industry's record-high $147.7 billion of capital expenditures in 2022 and generally constructive regulatory relations supported the increase in regulated assets. The 2022 capital expenditure total was the eleventh consecutive annual record high, with the expansion well represented across the industry's Regulated Electric and Natural Gas Distribution segments. Asset growth is also evident in the industry's net property, plant, and equipment in service, which rose 4.4% from year-end 2021 and 21.6% over the level at year-end 2018. Such robust growth in assets reflects the size of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure, and other capital projects in recent years.

## Competitive Energy

Competitive Energy assets decreased by $47.4 billion, or 22.7%, to $161.5 billion at year-end 2022 from $208.9 billion at year-end 2021. The large decrease was primarily driven by the spin-off of Constellation Energy, Exelon's power generation and competitive energy business, in February 2022. Competitive Energy revenue decreased by $14.3 billion, or 30.6%, to $32.5 billion from $46.8 billion in 2021. Competitive Energy covers the generation and/or sale of electricity in competitive markets, including both wholesale and retail transactions. Wholesale buyers are typically regional power pools, large industrial customers, and electric utilities looking to supplement generation capacity. Competitive Energy also includes the trading and marketing of natural gas. Of the 18 companies that maintain Competitive Energy operations, 11 (61%) grew these assets during 2022 and 16 (89%) had revenue gains from this segment.

## Natural Gas

Natural Gas Distribution assets increased by $29.7 billion, or 11.4%, to $291.4 billion at year-end 2022 from $261.7 billion at year-end 2021. The segment's revenue increased by $14.0 billion, or 26.1%, to $67.4 billion from $53.5 billion in 2021. This followed revenue growth of 18.0% in 2021 and a revenue decline of 3.3% in 2020. All 27 companies that report gas distribution revenue showed a year-to-year increase in 2022, consistent with the identical 100% of reporting companies that did so in 2021. This followed increases at 26%, 70%, 86% and 93% of reporting companies in 2020, 2019, 2018 and 2017, respectfully. Natural Gas Distribution includes the delivery of natural gas to homes, businesses and industrial customers throughout the United States.

Natural Gas Pipeline assets increased by $2.7 billion, or 8.2%, to $35.4 billion at year-end 2022 from $32.7 billion at year-end 2021. Five of the six companies that report this segment showed asset growth. Higher natural gas prices enabled the segment's revenue to increase by $1.0 billion, or 19.0%, to $6.5 billion in 2022 from $5.5 billion in 2021. The Natural Gas Pipeline business concentrates on the transmission and storage of natural gas for local distribution companies, marketers and traders, electric power generators and natural gas producers.

Added together, the Natural Gas Distribution and Natural Gas Pipeline segments increased assets by $32.4 billion, or 11.0%, in 2022 and produced revenue of $73.9 billion, up from $58.9 billion in 2021. The contribution to total industry revenue from these two natural gas activities increased to 17.0% in 2022 from 14.9% in 2021.

## Strategic Moves Completed in 2022

Several companies completed strategic transactions in 2022 that notably affected their business segmentation reporting.

- Exelon completed the separation of its regulated and competitive businesses into two publicly traded companies. Exelon said the separation gives each company the financial and strategic independence to focus on its specific customer needs while executing its core business strategy.
- PPL Corporation completed its acquisition of Rhode Island regulated utility Narragansett Electric Company from National Grid. PPL said the move finalized its strategic repositioning as a U.S.-focused energy company. The Narragansett Electric operations were renamed Rhode Island Energy.
- Public Service Enterprise Group (PSEG) completed the sale of its 6,750 MW portfolio of fossil generation units in New Jersey, Connecticut, Maryland, and New York to subsidiaries of ArcLight Energy Partners Fund. With this sale, PSEG concluded its transition to a 90% regulated company with a focus on clean energy and infrastructure investments.

## Strategic Announcements in 2022

In addition to 2022's completed transactions, several announcements were made that, if completed, will impact business segment reporting in 2023 and beyond.

- Dominion Energy announced the sale of its West Virginia natural gas utility, Hope Gas (also called Dominion Energy West Virginia) for $690 million to an infrastructure fund owned by insurance company Ullico. The Ullico infrastructure fund said it would integrate Hope Gas with Hearthstone Utilities, a portfolio company that owns and operates gas utilities in Indiana, Maine, Montana, North Carolina, and Ohio.
- AEP said it would divest unregulated commercial renewables businesses over the next two years and focus on transmission and regulated renewable investments.
- Eversource announced it would look to exit its joint venture with Danish wind energy developer Orsted, which was formed to develop offshore wind in New England. Eversource said potential proceeds would support the strengthening, modernizing, and decarbonizing of its regulated energy assets.
- Con Edison announced it would sell its wholly owned commercial renewables subsidiary, Con Edison Clean Energy Businesses, to RWE Renewables Americas for $6.8 billion. Con Edison said it will focus on its core utility businesses and the investments needed to lead New York's ambitious clean energy transition.
- Duke Energy announced that it would sell its commercial renewable energy business in response to strong investor demand for renewable energy infrastructure. Duke said the sale of its wind and solar portfolio will help reduce debt and fund growth in its regulated businesses.

## 2022 Year-End List of Companies by Category

Early each calendar year, we update our list of investor-owned electric utility holding companies organized by business category. The list is based on the prior year-end business segmentation data presented in 10-Ks. Our two categories are Regulated (80% or more of holding company assets are regulated) and Mostly Regulated (less than 80% of holding company assets are regulated).

We use assets rather than revenue for determining category membership because we believe assets provide a clearer picture of strategic trends; fluctuating commodity prices for natural gas and power can impact revenue so greatly that a company's strategic approach to business segmentation may be distorted by reliance on revenue data alone. Comparing the list of companies from year to year reveals company migrations between categories and shows the general trend in industry business models. We also base our quarterly category financial data during the year on this list.

In 2022, Exelon and Public Service Enterprise Group moved from the Mostly Regulated to the Regulated category. Exelon's regulated asset percentage rose above 80% due to the spin-off of Constellation Energy, Exelon's former power generation and competitive energy business. The transaction was completed on February 1, 2022. Public Service Enterprise Group's regulated asset

## List of Companies by Category at December 31, 2022

### Regulated (38)

Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
Avista Corporation
Black Hills Corporation
CenterPoint Energy, Inc.
*Cleco Corporate Holdings LLC**
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
*DPL Inc.**
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
IDACORP, Inc.
*IPALCO Enterprises, Inc.**
NiSource Inc.
NorthWestern Corporation
MGE Energy, Inc.
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
*Puget Energy, Inc.**
Sempra Energy
Southern Company
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

### Mostly Regulated (6)

ALLETE, Inc.
AVANGRID, Inc.
*Berkshire Hathaway Energy**
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.

Note:* Non-publicly traded companies.

percentage rose above 80% with the sale of PSEG's fossil generation units in New Jersey, Connecticut, Maryland, and New York. These two changes increased the number of Regulated companies to 38 from 36 and reduced the Mostly Regulated group to six companies from eight.

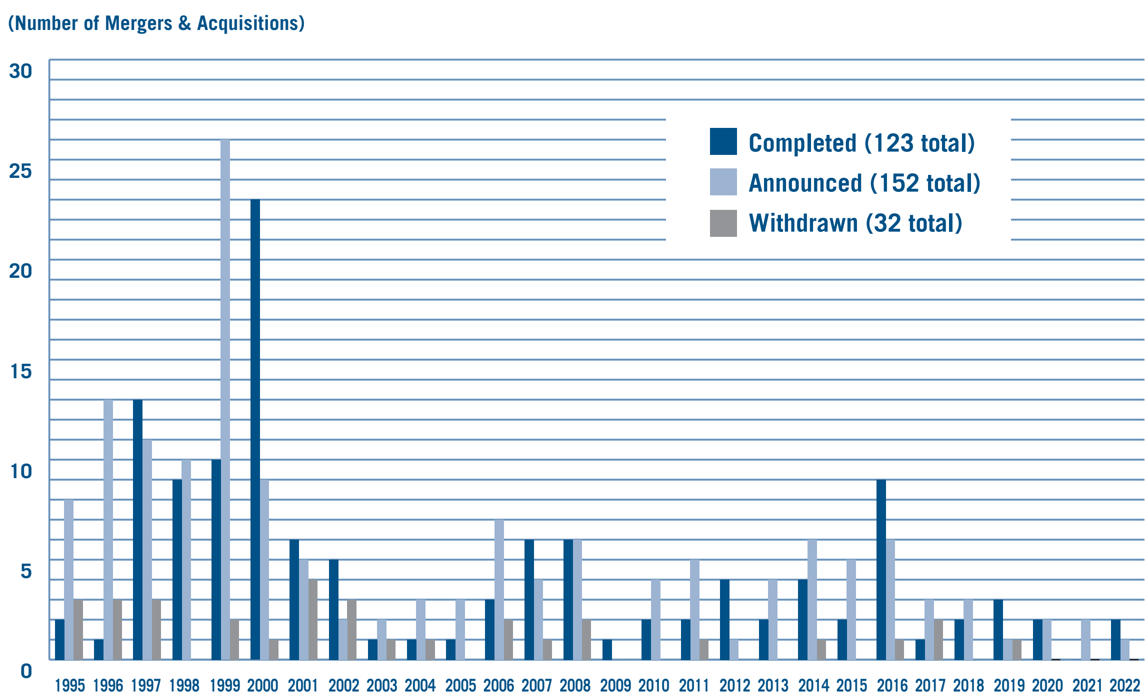
The number of parent companies in the EEI universe remained at 44, the same as the year-end 2021 total. (*See List of Companies by Category on December 31, 2022*).

## Mergers & Acquisitions

Utility merger and acquisition (M&A) activity involving whole operating companies with regulated service territories remained quiet in 2022. The only new announcement was Dominion's move to sell its West Virginia natural gas utility, Hope Gas, to an infrastructure fund owned by insurance company Ullico. In fact, the year-end number of publicly traded utilities tracked by EEI was 39 for a third straight year. By contrast, consolidation from the mid-1990s through 2019 reduced the number of utility holding companies by more than half, from 98 to 40. The reduced number of holding companies alone constrains the opportunity set for new M&A. But industry fundamentals do as well. Most utilities are focused on ambitious investment programs that seek internal earnings and dividend growth through expansion of regulated rate base focused on clean energy infrastructure. The Inflation Reduction Act (IRA), passed in August 2022, provided a strong public policy tailwind for clean energy investment, which already was strongly incentivized by state renewable portfolio standards, carbon mitigation programs and overwhelming policy support for clean energy from state regulators and the general public. Most of the now-smaller group of utilities don't see M&A as a priority — particularly given the well-known challenges steering deals through a potentially complex state and federal regulatory approval process. These challenges were evident in two of the five deals announced since the end of 2019. AVANGRID's October 2020 bid to acquire New Mexico-based PNM Resources remained stalled during 2022 after New Mexico regulators

## Status of Mergers & Acquisitions 1995–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: EEI Finance Department.

rejected the proposed transaction in late 2021. The sale of AEP's regulated subsidiary Kentucky Power to Liberty Utilities, a subsidiary of Canadian company Algonquin Power & Utilities, was blocked by the Federal Energy Regulatory Commission (FERC) in December 2022 due to concern over potentially higher transmission rates.

### *Infrastructure Fund to Buy Dominion's Hope Gas*

On February 11, 2022, Dominion Energy announced it planned to sell its West Virginia natural gas utility, Hope Gas (also called Dominion Energy West Virginia) for $690 million to an infrastructure fund owned by insurance company Ullico Inc., which provides insurance services to union employees across the U.S. Ullico's infrastructure business said it would integrate Hope Gas with Hearthstone Utilities, a portfolio company that owns and operates gas utilities in Indiana, Maine, Montana, North Carolina, and Ohio. As part of the agreement, Hearthstone said it will move its headquarters to West Virginia. Ullico said that Hope Gas is an example of a core infrastructure business that provides essential services, creates high quality jobs, and is a stabilizing force in the West Virginia economy. It noted the acquisition is consistent with its investment philosophy that favors long-term ownership, responsible labor policies and a commitment to local economic development. The transaction was completed on September 1, 2022. The sale of Hope Gas follows Dominion's 2021 sale of Questar, a natural gas pipeline business, to Southwest Gas Holdings for $1.975 billion, including the assumption of $430 million of existing debt.

## Status of Announced Mergers & Acquisitions
### 1995–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Year | Completed | Announced | Withdrawn |
|---|---|---|---|
| **1995** | 2 | 8 | 3 |
| **1996** | 1 | 13 | 3 |
| **1997** | 13 | 11 | 3 |
| **1998** | 9 | 10 | – |
| **1999** | 10 | 26 | 2 |
| **2000** | 23 | 9 | 1 |
| **2001** | 6 | 5 | 4 |
| **2002** | 5 | 2 | 3 |
| **2003** | 1 | 2 | 1 |
| **2004** | 1 | 3 | 1 |
| **2005** | 1 | 3 | – |
| **2006** | 3 | 7 | 2 |
| **2007** | 6 | 4 | 1 |
| **2008** | 6 | 6 | 2 |
| **2009** | 1 | – | – |
| **2010** | 2 | 4 | – |
| **2011** | 2 | 5 | 1 |
| **2012** | 4 | 1 | – |
| **2013** | 2 | 4 | – |
| **2014** | 4 | 6 | 1 |
| **2015** | 2 | 5 | – |
| **2016** | 9 | 6 | 1 |
| **2017** | 1 | 3 | 2 |
| **2018** | 2 | 3 | – |
| **2019** | 3 | 1 | 1 |
| **2020** | 2 | 2 | – |
| **2021** | – | 2 | – |
| **2022** | 2 | 1 | – |
| **Totals** | **123** | **152** | **32** |

Source: EEI Finance Department.

### *PPL Completes Narraganset Electric Purchase*

On May 25, 2022, PPL Corporation said it closed its acquisition of Rhode Island regulated utility Narragansett Electric Company, taking a little more than one year from the March 18, 2021 announcement date. Pennsylvania-based PPL Corporation announced in August 2020 it would seek to sell its U.K. utility distribution business, Western Power Distribution (WPD), and become a U.S. utility holding company focused on advancing the nation's clean energy goals with rate-regulated assets. That plan materialized in March 2021 when PPL announced an agreement to sell its

U.K. utility business, Western Power Distribution (WPD), to National Grid plc for £7.8 billion and, in a separate transaction, acquire National Grid's Rhode Island regulated utility business, The Narragansett Electric Company (NEC), for $3.8 billion. PPL said the strategic repositioning would refocus its strategy on strong, rate-regulated U.S. utilities, strengthen credit metrics and enhance long-term earnings growth and earnings predictability.

The agreement called for PPL to sell WPD to National Grid in an all-cash transaction valued at £14.4 billion, including assumption of £6.6 billion of debt, for net cash proceeds of approximately $10.2 billion. Separately, PPL planned to acquire Narragansett Electric from National Grid in a transaction valued at $5.3 billion, including the assumption of approximately $1.5 billion of Narragansett Electric debt. PPL said it planned to use a portion of the proceeds from the sale of WPD to finance the acquisition. PPL also highlighted its plan to play a key role in advancing Rhode Island's decarbonization goals, noting that its experience in automating electricity networks can help the state achieve its target of 100% renewable energy by 2030.

PPL said the closing of the Narragansett Electric acquisition completes its strategic repositioning as a U.S.-focused energy company. The Narragansett Electric operations were renamed Rhode Island Energy.

### *Two Recent Announcements Face Regulatory Headwinds*

The sole 2020 announcement that made EEI's list of whole company deals was AVANGRID's offer to acquire PNM Resources. AVANGRID said the transaction would support its U.S. growth strategy focused on regulated businesses and renewables in states with legal and regulatory stability and predictability. PNM, which operates regulated utilities in Texas and New Mexico, called the move a strategic fit that will help the utility invest in clean energy distribution and transmission and expand its position in renewables.

Despite widespread stakeholder support and approvals by PNM shareholders, Texas regulators and the FERC, the New Mexico Public Regulation Commission rejected the merger on December 8, 2021. News reports cited concern about reliability, potential rate increases and slower development of renewable resources by PNM as reasons for the move. Reports also noted nearly all intervening customers and clean energy advocates supported the merger, and that the PRC staff had said they would not oppose it. AVANGRID expressed disappointment with the decision but said it will evaluate next steps and hoped the merger could eventually succeed.

The deal remained in limbo throughout 2022 after media reports said PNM and Avangrid had appealed the rejection to the New Mexico Supreme Court. In early 2023, news reports said the New Mexico Public Regulation Commission had joined PNM and AVANGRID in requesting the Supreme Court to send the case back to the commission for a "rehearing and reconsideration" following a move by the state's governor to replace the previous five-member commission with a new three-member body.

In the other announcement, AEP announced in April 2021 that it was conducting a strategic review of its Kentucky operations. On October 26, 2021, the company announced a sale, which included Kentucky Power and AEP Kentucky Transco, to Liberty Utilities, a regulated subsidiary of Canadian utility holding company Algonquin Power & Utilities. AEP said it plans to use the expected $1.45 billion cash proceeds to eliminate equity needs as it boosts investment in regulated renewable energy infrastructure. However, in December 2022 the FERC, which rarely rejects proposed utility mergers, said the companies failed to show the deal would not have an adverse effect on transmission rates. In February 2023, the two companies said they were committed to completing the sale and filed a revised application with FERC.

### *Exelon/Constellation Complete Separation*

While not listed in the EEI mergers table, Exelon's move to separate its regulated and competitive businesses into two separate companies was a prominent industry event in 2021. The separation was completed on February 2, 2022. On February 24, 2021, Exelon announced a plan to split its six regulated utilities from its competitive power generation and customer-facing energy businesses, creating two publicly traded companies. Exelon said the separation gives each company the financial and strategic independence to focus on its specific customer needs while executing its core business strategy.

Exelon Corporation will continue as parent company for the fully regulated transmission and distribution utilities, which deliver electricity and natural gas to more than 10 million customers across five states and the District of Columbia. Constellation Energy Corporation will be the nation's largest supplier of clean energy with more than 31,000 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydro assets. Constellation will produce about 12 percent of the nation's carbon-free energy.

Exelon shareholders retained their shares of Exelon stock and received a pro-rata dividend of shares of Constellation. After the transaction closed on February 2, 2022, the regulated company retained the familiar EXC stock symbol while Constellation began trading under the symbol CEG.

Exelon noted the regulatory business is a high-quality utility asset with strong earnings growth of 6% to 8% annually and a diversified rate base across seven jurisdictions with constructive regulation. Exelon said the combination of strong operations and attractive ESG attributes provides a platform that supports transition to a clean energy economy without owning generation. The competitive business operates 18.7 gigawatts of nu-

**Merger Impacts 1995–2022**

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Date | No. of Utilities | Change |
|---|---|---|
| 12/31/95 | 98 | – |
| 12/31/96 | 98 | – |
| 12/31/97 | 91 | (7.14%) |
| 12/31/98 | 86 | (5.49%) |
| 12/31/99 | 83 | (8.79%) |
| 12/31/00 | 71 | (14.46%) |
| 12/31/01 | 69 | (2.82%) |
| 12/31/02 | 65 | (5.80%) |
| 12/31/03 | 65 | – |
| 12/31/04 | 65 | – |
| 12/31/05 | 65 | – |
| 12/31/06 | 64 | (1.54%) |
| 12/31/07 | 61 | (4.69%) |
| 12/31/08 | 59 | (3.28%) |
| 12/31/09 | 58 | (1.69%) |
| 12/31/10 | 56 | (3.45%) |
| 12/31/11 | 55 | (1.79%) |
| 12/31/12 | 51 | (7.27%) |
| 12/31/13 | 49 | (3.92%) |
| 12/31/14 | 48 | (2.04%) |
| 12/31/15 | 47 | (2.08%) |
| 12/31/16 | 44 | (6.38%) |
| 12/31/17 | 43 | (2.27%) |
| 12/31/18 | 42 | (2.33%) |
| 12/31/19 | 40 | (4.76%) |
| 12/31/20 | 39 | (2.50%) |
| 12/31/21 | 39 | – |
| 12/31/22 | 39 | – |

**Number of Companies Declined by 60% since Dec.'95**

Note: Based on completed mergers in the EEI Index group of electric utilities.

Source: EEI Finance Department.

clear generation and 12.3 gigawatts of natural gas, hydro, solar and wind energy. Constellation Energy also includes a retail business with a strong share of commercial and industrial energy customers in the nation's competitive energy markets.

### *Asset Sales Fund Regulated Clean Energy Capital Expenditures*

Asset sales rather than merger activity seemed to be the focus of utility corporate strategies in 2022. Many utilities sold assets to finance ambitious investment programs focused on clean energy infrastructure, transmission and reliability investments, to eliminate the need to raise equity capital, to avoid or reduce debt, or to accomplish restructurings.

Duke Energy and ConEd both announced plans to sell commercial renewable energy subsidiaries in the face of strong investor demand for renewable energy infrastructure. Duke said the sale of its 5,100 MW wind and solar portfolio would help reduce debt and fund growth in its regulated businesses, and said it hoped to complete a transaction during 2023.

On October 1, 2022, ConEdison announced it would sell its wholly owned commercial renewables subsidiary, Con Edison Clean Energy Businesses, to RWE Renewables Americas for $6.8 billion. Con Edison said it would cancel plans to issue up to $850 million of common equity in 2022 and focus on its core utility businesses and the investments needed to lead New York's ambitious clean energy transition.

In February 2022, AEP said it would divest unregulated commercial renewables businesses over the next two years and focus on transmission and regulated renewable investments. In February 2023, AEP announced it agreed to sell its 1,365-megawatt (MW) unregulated, contracted renewables portfolio to IRG Acquisition Holdings, a partnership owned by Invenergy, CDPQ and funds managed by Blackstone Infrastructure, at an enterprise value of $1.5 billion including project debt.

And in May 2022, Eversource announced it would look to exit its joint venture with Danish wind energy developer Orsted, which was formed to develop offshore wind off the New England coast. Eversource said potential proceeds would support the strengthening, modernizing and decarbonizing of its regulated energy assets.

At year-end 2022, Wall Street research suggested that M&A discussions across the industry were focused on financial sponsors rather than strategic buyers. With most utilities focused on organic growth through regulated clean energy capital expenditures, it would appear that viable strategic M&A would have to advance that agenda while also offering tangible benefits to rate payers. The Inflation Reduction Act of 2022 along with strong policy support from state renewable portfolio standards has convinced most industry observers that the long-term growth opportunities inherent in the clean energy transition have a long way to run. Deals that create synergies and lower costs may succeed, but the diminished number of utilities makes those combinations rarer than they once were. An economic downturn and/or persistent inflation may change the calculus for some companies, who may decide going it alone no longer makes sense if a larger parent can help fund capital expenditures at a lower cost to customers. Yet utility M&A is inherently a highly political process, and it's hard to translate those truisms into confident predictions. About the only thing certain as 2023 commences is the inevitability of the clean energy revolution and utilities' front and center role making it happen.

# Mergers & Acquisitions Announcements Updated through December 31, 2022

## U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Ann'cd | Buyer | Seller/Acquired/Merged | Status | New Company | Completed Date | Months to complete | Bus. | Terms | Est. Trans Value ($MM) |
|---|---|---|---|---|---|---|---|---|---|
| 2/11/22 | Ullico Inc. | Hope Gas, Inc. | Completed | | 8/31/22 | 6 | EG | Ullico Inc. paid $690 million in cash to acquire Hope Gas Inc. (parent company Dominion Energy) | 690.0 |
| 10/26/21 | Algonquin Power & Utilities Corp | Kentucky Power Company & AEP Kentucky Transmission Company Inc | Pending | | | | EE | $1.221 billion debt + $1.625 billion cash (valuation multiple of 1.3x rate base) | 2,846.0 |
| 3/18/21 | PPL Energy Holdings, LLC | Narragansett Electric Company | Completed | | 5/25/22 | 14 | EG | $1.5 billion debt + 3.8 billion cash (valuation multiple of 1.7x rate base) | 5,270.0 |
| 10/21/20 | AVANGRID | PNM Resources | Pending | | | | EE | AGR to pay $50.30/share in cash (roughly 10% premium) for PNM common stock | 4,300.0 |
| 7/5/20 | Berkshire Hathaway Energy | Dominion Energy Natural Gas Transportation and Storage | Completed | | 11/1/20 | 4 | EG | $5.7 billion debt + $4.0 billion cash | 9,700.0 |
| 6/3/19 | JP Morgan Investment Management | El Paso Electric | Completed | | 7/29/20 | 13 | EE | JPMorgan pays $68.25/share in cash for each share of El Paso Electric Co. common stock | 4,285.7 |
| 5/21/18 | NextEra Energy, Inc. | Gulf Power Company | Completed | | 1/1/19 | 7 | EE | NEE to pay $4.35 billion in cash to acquire Gulf Power Company from Southern Company | 4,350.0 |
| 4/23/18 | CenterPoint Energy | Vectren Corporation | Completed | | 2/1/19 | 10 | EG | CNP pays $72.00/share in cash for each share of Vectren common stock | 6,000.0 |
| 1/3/18 | Dominion Energy, Inc. | SCANA Corporation | Completed | | 1/1/19 | 12 | EE | $6.7B debt + $7.9 stock (per share value of $55.35, roughly 31% premium) | 14,600.0 |
| 8/21/17 | Sempra Energy | Oncor Electric Delivery Co | Completed | | 3/8/18 | 6 | EE | $9.5B cash | 9,450.0 |
| 7/19/17 | Hydro One Limited | Avista Corporation | Withdrawn | | 1/23/19 | | | $5.3B cash (per share value of $53.00, roughly 24% premium) | 5,300.0 |
| 7/7/17 | Berkshire Hathaway Inc. | Oncor Electric Delivery Co | Withdrawn | | 8/21/17 | | | $9.0B cash | 9,000.0 |
| 9/28/16 | DTE Energy | Appalachia Gathering System / Stonewall Gas Gathering | Completed | | 10/20/16 | 1 | EG | Undisclosed | 1,300.0 |
| 7/29/16 | NextEra Energy, Inc. | Oncor Electric Delivery Co | Withdrawn | | 10/31/17 | | | $6.8B debt + $4.4B cash | 11,178.0 |
| 5/31/16 | Great Plains Energy | Westar Resources | Completed | Evergy, Inc. | 6/5/18 | 24 | EE | $3.6B debt + $8.6 stock and cash (per share value of $60.00) | 12,200.0 |
| 2/9/16 | Fortis Inc. | ITC Holdings Corp. | Completed | | 10/14/16 | 8 | EE | $4.4B debt + $6.9B common shares and cash (per share value of $44.90, roughly 33% premium) | 11,300.0 |
| 2/9/16 | Algonquin Power & Utilities | Empire District Electric Co | Completed | | 1/1/17 | 11 | EE | $1.6B debt + additional debt and equity (per share value of $34.00, roughly 21% premium) | 2,400.0 |
| 2/1/16 | Dominion Resources, Inc. | Questar Corporation | Completed | | 9/16/16 | 8 | EG | $1.5B debt + $2.4B cash + $500M equity (per share value of $25.00, roughly 30% premium) | 4,400.0 |
| 10/26/15 | Duke Energy | Piedmont Natural Gas | Completed | | 10/3/16 | 12 | EG | $3.3B debt + $1.0B cash + $625M equity (per share value of $60.00, roughly 40% premium) | 4,900.0 |
| 9/4/15 | Emera | TECO Energy, Inc. | Completed | | 7/1/16 | 10 | EE | $6.5B debt + $3.9B equity (per share value of $27.55, roughly 48% premium) | 10,400.0 |
| 8/24/15 | Southern Company | AGL Resources | Completed | | 7/1/16 | 10 | EG | $4.1B debt + $8.0B equity (per share value of $66.00, roughly 36% premium) | 12,060.4 |
| 7/12/15 | Black Hills Corporation | SourceGas Holdings | Completed | | 2/12/16 | 10 | GG | $760M debt + $1.13B cash | 1,890.0 |
| 2/25/15 | Iberdrola USA | UIL Holdings | Completed | AVANGRID, Inc. | 12/16/15 | 10 | EE | $1.8B debt + $0.6B cash + $2.4B equity (per share value of $52.75, roughly 25% premium, of which $10.50 will be cash) | 4,756.0 |
| 12/3/14 | NextEra Energy, Inc. | Hawaiian Electric | Withdrawn | | 7/18/16 | | EE | NEE to acquire HE for $2.6B equity + $1.4B debt (fixed exchange ratio of 0.2413 NEE shares) | 3,963.0 |
| 10/20/14 | Macquarie-led Consortium | Cleco | Completed | | 4/13/16 | 18 | EE | $3.4B equity (all Cleco shares at $55.37 / share in cash (~15% premium)) + $1.3 debt | 4,700.0 |
| 6/23/14 | Wisconsin Energy | Integrys | Completed | WEC Energy Group | 6/30/15 | 12 | EE | WEC to acquire TEG for $5.758B equity + $3.374B debt (fixed exchange ratio of 1.128 WEC shares + $18.58) | 9,100.0 |
| 5/1/14 | Berkshire Hathaway Energy | AltaLink (Canadian) | Completed | | 12/1/14 | 7 | ET | BHE to acquire AL for $3.2B cash + $2.7B debt | 5,927.0 |
| 4/30/14 | Exelon | Pepco | Completed | | 3/23/16 | 24 | EE | EXC to acquire POM for $6.8B in cash ($27.25 per POM share) | 12,337.0 |
| 3/3/14 | UIL Holdings | Philadelphia Gas Works | Withdrawn | | 12/4/14 | | EG | UIL to acquire assets & liabilities of PGW from city of Philadelphia for $1.86 billion in cash | 1,860.0 |
| 12/12/13 | Fortis Inc. | UNS Energy | Completed | | 8/15/14 | 8 | EE | Fortis pays $60.25 / share (31% premium to announcement day's close) + $1.8B in debt | 4,578.1 |
| 11/4/13 | Avista | Alaska Energy & Resources Company | Completed | | 7/1/14 | 8 | EE | AVA to acquire Alaska Energy & Resources Company for $145MM equity + $24.5MM debt | 169.5 |
| 5/29/13 | MidAmerican Energy Holdings Co. | NV Energy | Completed | Berkshire Hathaway Energy | 12/19/13 | 7 | EE | MidAmerican pays $23.75 / share + assume $4.8 billion debt | 10,494.3 |
| 5/25/13 | TECO Energy, Inc. | New Mexico Gas Intermediate, Inc. | Completed | | 9/2/14 | 15 | EE | TECO will pay $950 million, including assume $200 million debt to Continental Energy Systems LLC | 950.0 |
| 2/20/12 | Fortis Inc. | CH Energy Group | Completed | | 6/27/13 | 16 | EE | Fortis pays $65.00/share cash & assumes approx. $687.37 MM debt. | 1,609.7 |
| 5/27/11 | Fortis Inc. | Central Vermont Public Service Corp | Withdrawn | | 7/11/11 | | EE | Fortis pays approx. $35.10/share cash & assumes approx. $226.4 mill in debt. | 701.6 |
| 1/8/11 | Duke Energy | Progress Energy | Completed | | 7/3/12 | 18 | EE | 0.87083 Duke shares (after 1-3 reverse split) for each Progress share + assume $12.1 billion net debt. | 32,000.0 |
| 7/11/11 | Gaz Metro LP | Central Vermont Public Service Corp | Completed | | 6/27/12 | 12 | GE | Gaz Métro pays $35.25/share for each CVPS share & assumes $226 million debt. | 704.2 |
| 10/16/10 | Northeast Utilities | NSTAR | Completed | | 4/10/12 | 18 | EE | 1.312 NU shares for each NSTAR shr, plus $3.36 bill assume debt | 7,566.7 |
| 4/28/11 | Exelon Corp. | Constellation Energy Group Inc. | Completed | | 3/12/12 | 11 | EE | CEG receive 0.93 shares of EXC for each CEG share. EXC assumes approx. $2.9 bill net debt | 10,623.2 |
| 4/19/11 | AES Corporation | DPL Inc. | Completed | | 11/28/11 | 7 | EE | AES pays 30.00/share cash & assumes approx $1.1 billion of net debt | 4,613.2 |
| 4/28/10 | PPL Corp. | E.ON U.S. | Completed | | 11/1/10 | 6 | EE | $6.83 billion cash + $764.0 million in assumed debt | 7,625.0 |
| 3/12/10 | Emera Inc | Maine & Maritimes | Completed | | 12/21/10 | 9 | EE | $76 mm cash + $28.6 mm debt + $13.8mm postretirement benefits | 117.4 |
| 2/10/10 | FirstEnergy | Allegheny Energy | Completed | | 2/25/11 | 12 | EE | $4.3 billion in equity + $4.7 billion in assumed debt | 9,273.2 |
| 9/17/08 | Berkshire Hathaway | Constellation Energy Group Inc. | Withdrawn | | 12/17/08 | | PE | $4.7 bill cash + $4.4 bill net debt and adjustments | 9,152.5 |
| 7/25/08 | Sempra Energy | EnergySouth Inc. | Completed | | 10/1/08 | 3 | EG | $499 million cash + 283 million debt | 771.9 |
| 7/1/08 | MDU Resources Group, Inc. | Intermountain Gas Co. | Completed | | 10/1/08 | 3 | EG | $245 million cash + $82 million debt | 327.0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 6/25/08 | Duke Energy | Catamount Energy Corp. | Completed | | 9/15/08 | 3 | EP | $240 million cash + $80 million assumed debt | 320.0 |
| 2/15/08 | Unitil Corp. | Northen Utilities / Granite State Gas Transmission | Completed | | 12/1/08 | 10 | EG | $160 million cash | 160.0 |
| 1/12/08 | PNM Resources, Inc. | Cap Rock Holding Corp. | Withdrawn | | 7/22/08 | | EE | $202.5 million | 202.5 |
| 10/26/07 | Macquarie Consortium | Puget Energy | Completed | | 2/6/09 | 16 | EE | $3.5 billion cash + $3.02 billion net debt | 6,520.2 |
| 6/25/07 | Iberdrola S.A. | Energy East Corp. | Completed | | 9/16/08 | 15 | EE | $4.5 billion cash + $4.1 billion net debt | 8,600.0 |
| 2/26/07 | KKR & Texas Pacific Group | TXU Corp.[1] | Completed | Energy Future Holdings Corp. | 10/10/07 | 8 | PE | $31.8 billion cash + $12.1 billion net debt | 43,882.0 |
| 2/7/07 | Black Hills Corp. / Great Plains Energy Inc.[2] | Aquila Inc. (CO elec. util. + CO, KS, NE, IA gas utils.) | Completed | | 7/14/08 | 17 | EG | $940 million cash +working capital and other adjustments | 940.0 |
| 7/8/06 | MDU Resources Group, Inc. | Cascade Natural Gas Corporation | Completed | | 7/2/07 | 12 | EG | $305.2mm in cash + ($173.6 in debt - $13.0 in cash equivalents) | 465.8 |
| 7/8/06 | WPS Resources Corporation | Peoples Energy Corporation | Completed | Integrys Energy Group | 2/21/07 | 7 | EG | $2.47 billion | 2,472.4 |
| 7/5/06 | Macquarie Consortium | Duquesne Light Holdings | Completed | | 5/31/07 | 10 | EE | $1.59 billion cash + $1.09 billion total debt | 2,674.4 |
| 6/22/06 | Gaz Metro LP | Green Mountain Power Corp. | Completed | | 4/12/07 | 10 | EE | $187 million in cash + ($100.8 debt - $9.1mm in cash equivalents) | 279.5 |
| 5/11/06 | ITC Holdings Corp | Michigan Electric Transmission Co. | Completed | | 10/10/06 | 5 | EE | $485.6mm cash + $70mm common stock + $311mm assumed debt | 866.6 |
| 4/25/06 | Babcock and Brown Infrastructure | NorthWestern Corp. | Withdrawn | | 7/24/07 | | EE | $2.2 billion cash | 2,200.0 |
| 2/27/06 | National Grid | KeySpan Corp. | Completed | | 8/24/07 | 18 | EE | $7.4 billion cash + $4.5 billion long-term debt | 11,877.5 |
| 12/19/05 | FPL Group Inc. | Constellation Energy Inc. | Withdrawn | | 10/25/06 | | EE | $11.3 billion equity + $4.1 billion net debt and pension liabilities | 15,311.5 |
| 5/24/05 | MidAmerican Energy Holdings Co. | Pacificorp | Completed | | 3/21/06 | 10 | EE | $5.1 billion cash + $4.3 billion in net debt and preferred stock | 9,300.0 |
| 5/9/05 | Duke Energy Corp. | Cinergy Corp. | Completed | | 4/3/06 | 11 | EE | $9.1 billion equity + $5.5 billion net debt and pension liabilities | 14,600.0 |
| 12/20/04 | Exelon Corp. | Public Service Enterprise Group | Withdrawn | | 9/14/06 | | EE | $12.3 billion in equity + $13.4 billion in net debt and pension liabilities | 25,700.0 |
| 7/25/04 | PNM Resources | TNP Enterprises | Completed | | 6/6/05 | 12 | EE | $189 million in stock and cash and $835 million in debt | 1,024.0 |
| 2/3/04 | Ameren Corp | Illinois Power[3] | Completed | | 10/1/04 | 8 | EE | $1.9 billion in debt, pref stock, & other liab + $400 million in cash | 2,300.0 |
| 11/24/03 | Saguaro Utility Group L.P. | UniSource Energy | Withdrawn | | 12/30/04 | | PE | $850 million cash + $2 billion in debt | 2,850.0 |
| 11/3/03 | Exelon Corp. | Illinois Power | Withdrawn | | 11/22/03 | | EE | $275 million cash + $1.8 billion in debt + $150 million promissory note | 2,225.0 |
| 4/30/02 | Aquila Inc | Cogentrix Energy Inc | Withdrawn | | 8/2/02 | | EIPP | $415 million cash + $1.125 billion in assumed debt | 1,540.0 |
| 4/29/02 | Ameren Corp | CILCORP[4] | Completed | | 1/31/03 | 9 | EE | $541 million cash + $781 in assumed debt + $41 million in pref stock | 1,400.0 |
| 10/8/01 | Northwest Natural Gas | Portland General | Withdrawn | | 5/16/02 | | GE | $1.55 billion cash + $250mm in stock | 1,800.0 |
| 9/20/01 | Duke Energy | Westcoast Energy | Completed | | 3/14/02 | 6 | EG | Equity + cash valued at $27.90 per Westcoast share | 8,500.0 |
| 9/10/01 | Dominion Resources | Louis Dreyfus Natural Gas | Completed | | 11/1/01 | 2 | EG | $890mm cash + $900mm stock +$505mm debt | 2,295.0 |
| 2/20/01 | Energy East | RGS Energy | Completed | | 6/28/02 | 16 | EE | $1.4 bill. cash & equity + $1.0 bill. net debt | 2,400.0 |
| 2/12/01 | Pepco | Conectiv | Completed | | 8/1/02 | 18 | EE | $2.2 bill cash & equity + $2.8 bill. net debt | 5,000.0 |
| 11/9/00 | PNM | Western Resources[5] | Withdrawn | | 1/8/02 | | EE | Stock transfer | 4,442.0 |
| 10/2/00 | NorthWestern | Montana Power[6] | Completed | | 2/15/02 | 16 | EE | $1.1 billion in cash | 1,100.0 |
| 9/5/00 | National Grid Group | Niagara Mohawk | Completed | | 1/31/02 | 16 | EE | $19 per share | 8,900.0 |
| 8/8/00 | FirstEnergy | GPU Inc. | Completed | | 11/7/01 | 15 | EE | $35.60 per share | 12,000.0 |
| 7/31/00 | FPL Group | Entergy | Withdrawn | | 4/2/01 | | EE | 1/1 - FPL, 0.585/1 - ETR | 27,000.0 |
| 7/17/00 | AES Corporation | IPALCO | Completed | | 3/27/01 | 8 | IPPE | $25 per share | 3,040.0 |
| 6/30/00 | NS Power | Bangor Hydro | Completed | Emera | 10/10/01 | 16 | EE | $26.50 per share | 206.0 |
| 5/30/00 | WPS Resources | Wisconsin Fuel and Light | Completed | | 4/2/01 | 11 | EG | 1.73 shares of WPSR | 55.0 |
| 2/28/00 | PowerGen plc | LG&E | Completed | | 12/11/00 | 10 | EE | $24.85 per share | 5,400.0 |
| 8/8/00 | FirstEnergy | GPU Inc. | Completed | | 11/7/01 | 15 | EE | $35.60 per share | 12,000.0 |
| 7/31/00 | FPL Group | Entergy | Withdrawn | | 4/2/01 | | EE | 1/1 - FPL, 0.585/1 - ETR | 27,000.0 |
| 7/17/00 | AES Corporation | IPALCO | Completed | | 3/27/01 | 8 | IPPE | $25 per share | 3,040.0 |
| 6/30/00 | NS Power | Bangor Hydro | Completed | Emera | 10/10/01 | 16 | EE | $26.50 per share | 206.0 |
| 5/30/00 | WPS Resources | Wisconsin Fuel and Light | Completed | | 4/2/01 | 11 | EG | 1.73 shares of WPSR | 55.0 |
| 2/28/00 | PowerGen plc | LG&E | Completed | | 12/11/00 | 10 | EE | $24.85 per share | 5,400.0 |

[1] TXU (now Energy Future Holdings Corp.) was acquired by the Texas Energy Future Holdings Limited Partnership (TEF) on 10/10/2007. TEF was formed by a group of investors led by Kohlberg Kravis Roberts and Texas Pacific Group to facilitate the merger.

[2] Aquila was divided with Black Hills Corp. acquiring the electric utility in Colorado and NG utilities in CO, IA, KS, and NE. Great Plains Energy Inc. acquired the MI electric utility, stock, and other corporate assets.

[3] Ameren purchased Illinois Power from Dynegy Corporation. Dynegy Corp acquired Illinois Power in February 2000.

[4] Ameren purchased CILCORP from AES Corporation. AES Corp acquired CILCORP in October 1999.

[5] PNM purchased Western Resources' electric operations including generation, transmission, and distribution.

[6] NorthWestern Corporation purchased Montana Power's electric and natural gas transmission and distribution assets.

General Note: sum of Announced, Completed, Withdrawn, and Pending may not total due to inclusion of transactions announced prior to the 1994 window (e.g., a transaction announced in 1993 and completed in 1994 is included as a completion, but not as an announcement).

| | |
|---|---|
| C = Completed | E = Electric |
| W = Withdrawn | G = Gas |
| PN = Pending | O = Oil |
| | IPP = Independent Power Producer |
| | P = Privatized |

Source: EEI Finance Department, SNL Financial

## Construction

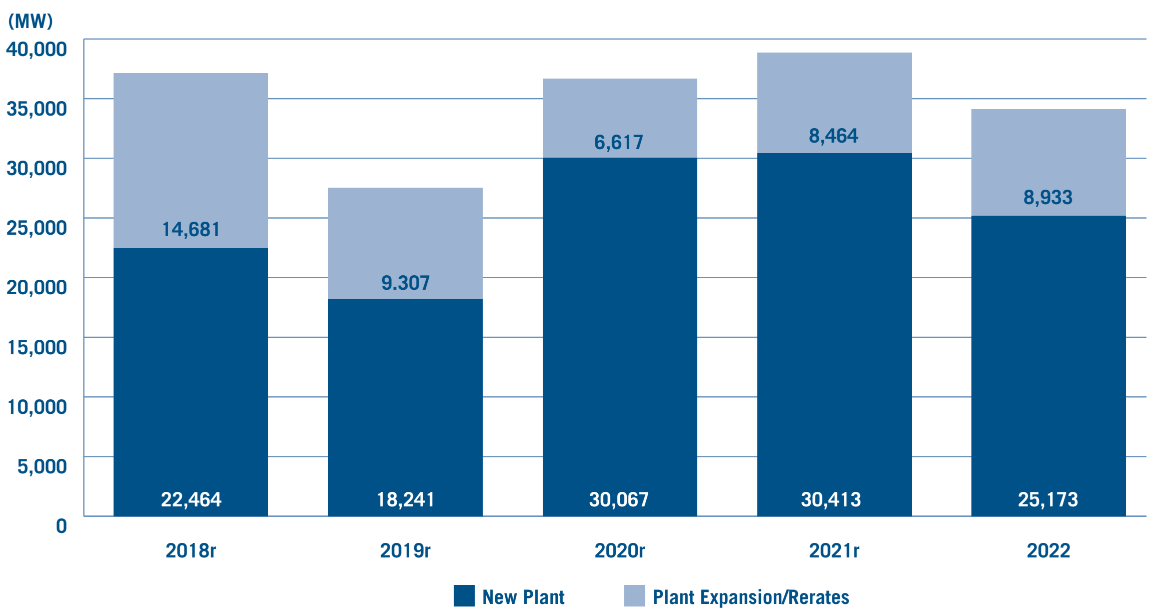
The electric utility industry brought 34,106 MW of new capacity online in 2022, 12% less than 2021's 38,877 MW and 7% less than the 36,684 MW of 2020. The decline from 2021 to 2022 was due to reductions in both solar and wind capacity. Supply chain issues continuously plagued wind and solar projects in 2022, causing many to be delayed. As a result, new wind capacity brought online decreased from 12,875 MW in 2021 to 10,148 MW in 2022. Solar capacity installation decreased 22%, from 15,370 MW in 2021 to 11,953 MW in 2022, marking the first annual decline for solar since 2018. Despite supply chain challenges, new natural gas capacity brought online increased from 6,924 MW in 2021 to 7,067 MW in 2022, marking natural gas's first annual increase since 2018.

New plants comprised 74% of 2022's total new capacity. Expansions and rerates accounted for the remaining 26%. The percentage of new plants slightly declined from 2021's rate of 78%.

Renewables continued to lead capacity additions, accounting for 65% of new capacity in 2022 versus 73% in 2021, even though supply chain challenges pushed some of 2022's scheduled projects into 2023. Supported by continually declining costs, wind and solar have powered more than half of the new capacity in each of the last four years. Solar led new capacity additions in 2022, accounting for 11,953 MW or 35% of the total across all fuels. Wind was second with 10,148 MW, or 30%. Investor-owned utilities that brought the most new renewable capacity online were NextEra Energy (2,682 MW of wind, 1,322 MW of solar), American Electric Power (999 MW of wind, 22 MW of solar), Duke Energy (207 MW of wind, 694 MW

## New Capacity Online (MW) 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY



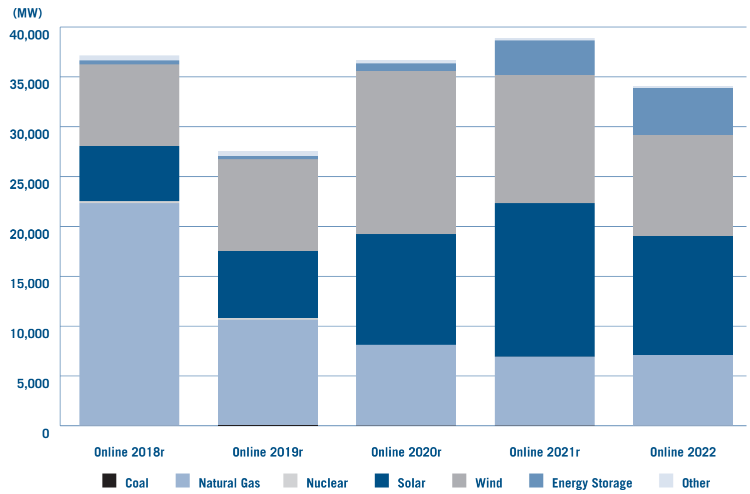

r = revised

Note: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

**New Capacity Online by Fuel Type (MW) 2018–2022**

U.S. ELECTRIC UTILITY AND NON-UTILITY




| Fuel Type | 2018r | 2019r | 2020r | 2021r | 2022 |
|---|---|---|---|---|---|
| Coal | 0 | 62 | 30 | 11 | 0 |
| Natural Gas | 22,320 | 10,549 | 8,078 | 6,924 | 7,067 |
| Nuclear | 192 | 175 | 20 | 0 | 17 |
| Solar | 5,542 | 6,714 | 11,083 | 15,370 | 11,953 |
| Wind | 8,187 | 9,232 | 16,343 | 12,875 | 10,148 |
| Energy Storage | 381 | 306 | 767 | 3,483 | 4,676 |
| Other | 524 | 510 | 362 | 215 | 246 |
| **Total** | **37,145** | **27,548** | **36,684** | **38,877** | **34,106** |

r = revised

Note: Includes all new capacity placed on the grid by U.S. investor-owned utilities, independent power producers, municipals, co-ops, government authorities and corporations. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, water, and wood. Totals may reflect rounding.

The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

of solar), Xcel (322 MW of wind), AES (67 MW of wind, 252 MW of solar), ALLETE (304 MW of wind, 7 MW of solar), WEC Energy Group (300 MW of wind, 8 MW of solar), National Grid (275 MW of solar), Alliant Energy (254 MW of solar), and Ameren Corporation (202 MW of wind, 8 MW of solar).

Natural gas accounted for 21% of new capacity added in 2022; the year's 7,067 MW total was 2% higher than 2021's 6,924 MW. Combined cycle technology accounted for 78% of 2022's new natural gas capacity compared with 44% in 2021. Combustion turbines powered 20%. New plants represented 51% of the year's natural gas total, expansions accounted for 45% and the remaining 4% were rerates. DTE Energy led natural gas additions with 1,267 MW in new combined cycle gas plants, followed by NextEra Energy, whose gas turbine expansions totaled 1,163 MW. Third was Northwestern Corp. with 69 MW of new gas turbine capacity.

Energy storage accounted for nearly all the remaining 14% of new capacity added in 2022; a total of 4,676 MW was brought online, a 34% increase from 2021. Investor-owned utilities that brought the most energy storage capacity online included NextEra Energy (547 MW), AES Corporation (257 MW), PG&E Corporation (183 MW), and National Grid (125 MW).

## New Capacity Online by Region

The Western Electricity Coordinating Council (WECC) brought the most capacity online of any region; WECC's 8,751 MW total for 2022 was 867 MW, or 11%, higher than 2021's 7,884 MW. An increase in new energy storage, from 1,993 MW to 2,992 MW, was the primary contributor to the gain. The Alaska Systems Coordinating Council (ASCC) also increased new capacity compared to 2021, rising from 9 MW in 2021 to 54 MW in 2022. The Hawaiian Coordinating Council (HCC) was the third and last region where new capacity brought online rose compared to 2021; new capacity in the HCC totaled 63 MW in 2021 and 81 MW in 2022. The year-to-year increase in HCC was driven by new solar additions, at 42 MW compared to 17 MW in 2021, which was slightly offset by a 7 MW decline in energy storage additions.

The SERC Reliability Corporation had the largest absolute decrease in new capacity added, from 8,054 MW in 2021 to 5,807 MW in 2022. The decline resulted from reduced additions of solar (4,746 MW to 3,834 MW), wind (887 MW to 121 MW), and energy storage (582 MW to 91 MW). New capacity added in The Electric Reliability Council of Texas (ERCOT) also declined more than 1,300 MW, falling 14% from

## New Capacity Online by Region (MW) 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY

| Region | Online 2018r | Online 2019r | Online 2020r | Online 2021r | Online 2022 |
|---|---|---|---|---|---|
| ASCC | 2 | 34 | 8 | 9 | 54 |
| HCC | 155 | 221 | 60 | 63 | 81 |
| MRO | 3,320 | 3,321 | 5,068 | 2,921 | 2,374 |
| NPCC | 3,386 | 2,267 | 1,693 | 1,566 | 1,038 |
| RFC | 11,980 | 4,047 | 2,783 | 6,150 | 5,175 |
| SERC | 9.577 | 7,322 | 8,970 | 8,054 | 5,807 |
| SPP | 1,922 | 1,142 | 3,366 | 2,740 | 2,705 |
| TRE/ERCOT | 2,935 | 5,312 | 5,997 | 9,490 | 8,121 |
| WECC | 3,868 | 3,883 | 8,739 | 7,884 | 8,751 |
| **Total** | **37,145** | **27,548** | **36,684** | **38,877** | **34,106** |

r = revised

Note: Data includes U.S. new plants, rerates, and expansions of existing plants, including nuclear uprates. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

## Announced New Capacity by Region and Fuel Type in 2022 (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY

| Fuel Type | Alaska Systems Coordinating Council | Reliability Council of Texas | Hawaiian Coordinating Council | Midwest Reliability Organization | Northeast Power Coordinating Council | Reliability First | SERC Reliability Corp | Southeast Power Pool Inc. | Western Electricity Coordinating Council |
|---|---|---|---|---|---|---|---|---|---|
| **Coal** | - | - | - | - | - | - | - | - | - |
| **Natural Gas** | - | 361 | - | 132 | - | 65 | 780 | - | - |
| **Nuclear** | - | - | - | - | - | - | - | - | - |
| **Wind** | - | - | - | 1,212 | 2,209 | 1,046 | 763 | 453 | 5,801 |
| **Solar** | - | 4,622 | 79 | 2,271 | 4,029 | 5,222 | 11,854 | 1,065 | 7,947 |
| **Hydro** | - | - | - | - | 1 | 1 | - | 32 | 8 |
| **Energy Storage** | - | 5,306 | 157 | 344 | 8,477 | 162 | 518 | - | 7,560 |
| **Other** | - | - | - | - | - | 329 | - | 9 | 7 |
| **Total** | **-** | **10,289** | **236** | **3,958** | **14,715** | **6,825** | **13,915** | **1,559** | **21,323** |

r = revised

Notes: Data includes new plants and expansions of existing plants announced, including nuclear uprates. Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, and wood. Totals may reflect rounding.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

## Stage of Announced Capacity Additions (MW) 2023–2027

U.S. ELECTRIC UTILITY AND NON-UTILITY

| Fuel | Proposed | Feasibility | Application Pending | Permitted | Site Prep | Under Construction | Testing | Total |
|---|---|---|---|---|---|---|---|---|
| **Natural Gas** | 13,699 | 497 | 5,129 | 7,484 | 175 | 6,564 | 3,978 | 37,525 |
| **Nuclear** | 1,753 | - | - | - | - | - | 2,200 | 3,953 |
| **Solar** | 105,689 | 200 | 41,616 | 43,734 | 100 | 31,101 | 5,197 | 227,638 |
| **Wind** | 63,858 | 2,212 | 13,239 | 11,256 | 352 | 10,772 | 1,963 | 103,652 |
| **Energy Storage** | 41,368 | 8,971 | 27,634 | 13,537 | - | 8,657 | 953 | 101,121 |
| **Other** | 1,340 | 1,943 | 66 | 316 | - | 233 | 2 | 3,900 |
| **Grand Total** | **227,707** | **13,823** | **87,684** | **76,327** | **627** | **57,328** | **14,292** | **477,789** |

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, hydroelectric turbines, and wood. Totals may reflect rounding. Data includes new plants and expansions of existing plants, including nuclear uprates. Data includes projects with an expected online date up to 2027.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

9,490 MW in 2021 to 8,121 MW in 2022. That decline was led by lower solar (4,204 MW to 2,414 MW), gas (1,242 MW to 1,011 MW), and wind (3,393 MW to 3,332 MW) and was partially offset by an increase in energy storage capacity (641 MW to 1,364 MW).

### Announcements by Region and Fuel Type

New capacity announced in 2022 totaled 72,819 MW, an increase of 43% over 2021's 51,032 MW. Renewable capacity accounted for 67% of 2022's total, with solar at 51%, wind at 16%, and hydro at 0.1%. Energy storage accounted for 31%. The remaining 2% was natural gas. As in 2021, no new coal or nuclear capacity was announced in 2022.

Energy storage produced the strongest year-to-year growth in announced new capacity with 22,522 MW announced in 2022. Northeast Power Coordinating Council (NPCC), Western Electricity Coordinating Council (WECC), and Electric Reliability Council of Texas (ERCOT) together accounted for 95%, or 21,342 MW, of the total new storage capacity announcements in 2022.

Higher wind and solar announcements also contributed to the growth in 2022 versus 2021. Announced new wind capacity increased 32%, from 8,668 MW in 2021 to 11,484 MW in 2022. New solar capacity announcements rose 6%, from 35,107 MW in 2021 to 37,089 MW in 2022. Federal government support for clean energy investment included in the Inflation Reduction Act (August 2022) and in the Infrastructure Investment and Jobs Act (November 2021) may have contributed to higher renewable capacity announcements in 2022 compared to 2021.

Announced new natural gas capacity decreased for the third year in a row, falling 56% from 3,060 MW in 2021 to 1,337 MW in 2022. Only four regions had new announcements: SERC Reliability Corporation (SERC), Electric Reliability Council of Texas (ERCOT), Midwest Reliability Organization (MRO), and Reliability First Corporation (RFC).

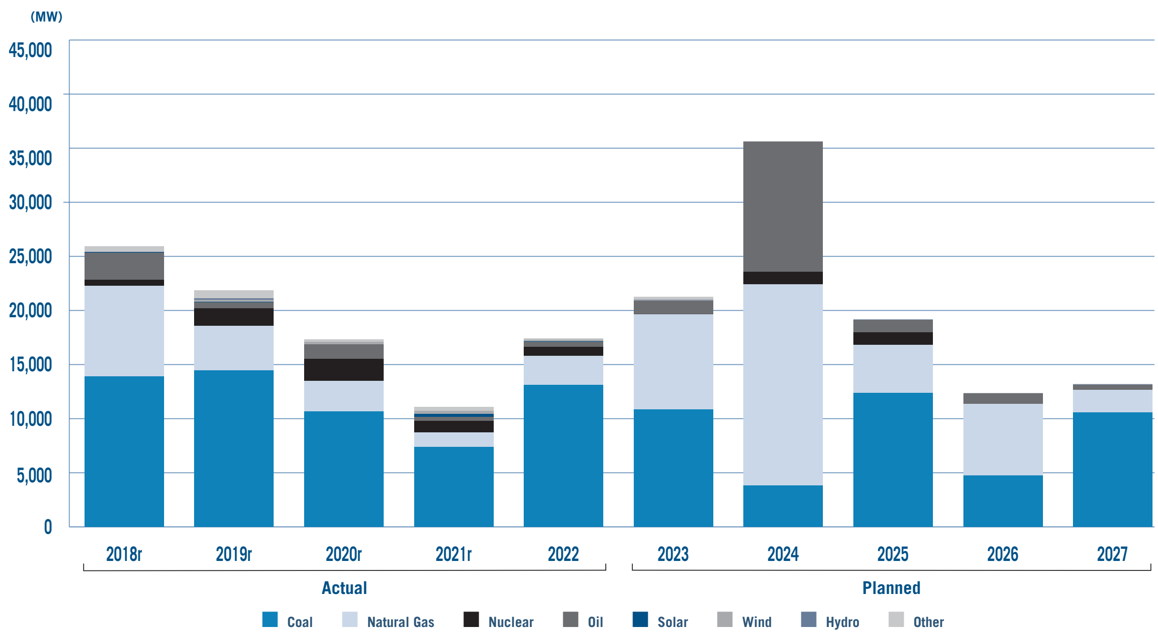
The Western Electricity Coordinating Council (WECC) saw the most announced new capacity of any region for the third year in a row, at 21,323 MW; 65% of that is renewable, with 37% solar, 27% wind, and less than 1% hydro. The remaining 35% is energy storage. The Northeast Power Coordinating Council (NPCC) region saw the second-highest amount of announced new capacity in 2022, at 14,715 MW; 58% is energy storage while the remaining 42% is renewable (27% solar and 15% wind).

### Projected Capacity Additions

As of April 2023, new capacity expected to come online from 2023 through 2027 totaled 477,789 MW, a 31% increase over the comparable projection one year ago for the 2022 through 2026 five-year period. Renewable capacity accounted for most of the total, with solar representing 48% and wind accounting for 22%. The third-largest category was energy storage, at 21%, followed

## Actual 2018-2022 and Projected 2023-2027 Retirements (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY




| | Actual | | | | | Planned | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2018r | 2019r | 2020r | 2021r | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Total |
| **Coal** | 13,877 | 14,460 | 10,648 | 7,361 | 13,092 | 10,852 | 3,826 | 12,382 | 4,759 | 10,546 | 42,365 |
| **Natural Gas** | 8,400 | 4,110 | 2,853 | 1,357 | 2,720 | 8,804 | 18,593 | 4,418 | 6,574 | 2,092 | 40,482 |
| **Nuclear** | 550 | 1,641 | 2,031 | 1,074 | 823 | - | 1,159 | 1,164 | - | - | 2,323 |
| **Oil** | 2,483 | 546 | 1,337 | 383 | 476 | 1,232 | 11,993 | 1,191 | 1,004 | 488 | 15,908 |
| **Solar** | 3 | 8 | - | 275 | 2 | - | - | - | 1 | 4 | 5 |
| **Wind** | 63 | 208 | 229 | 235 | 168 | 41 | - | 1 | - | - | 43 |
| **Hydro** | 55 | 161 | 9 | 6 | 9 | 38 | 5 | 14 | 10 | 24 | 92 |
| **Other** | 481 | 738 | 211 | 379 | 126 | 283 | 67 | 1 | - | 50 | 401 |
| **Total** | **25,910** | **21,872** | **17,318** | **11,070** | **17,415** | **21,250** | **35,644** | **19,171** | **12,348** | **13,204** | **101,617** |

r = revised

Notes: Other includes biomass, diesel/fuel oil, fuel cells, geothermal, landfill gas, pet coke, waste heat, wood, and energy storage. Totals may reflect rounding. 2018-2022 is actual plants retired. 2023-2027 is projected based on announced or expected retirements.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

by natural gas at 8% and nuclear at 1%. Natural gas and nuclear were 13% and 2%, respectively, of the 2022 through 2026 five-year total. Of the 477,789 MW total, 48% was in the proposal stage as of April 2023. Only 12% of the total was under construction and 3% was in the testing stage.

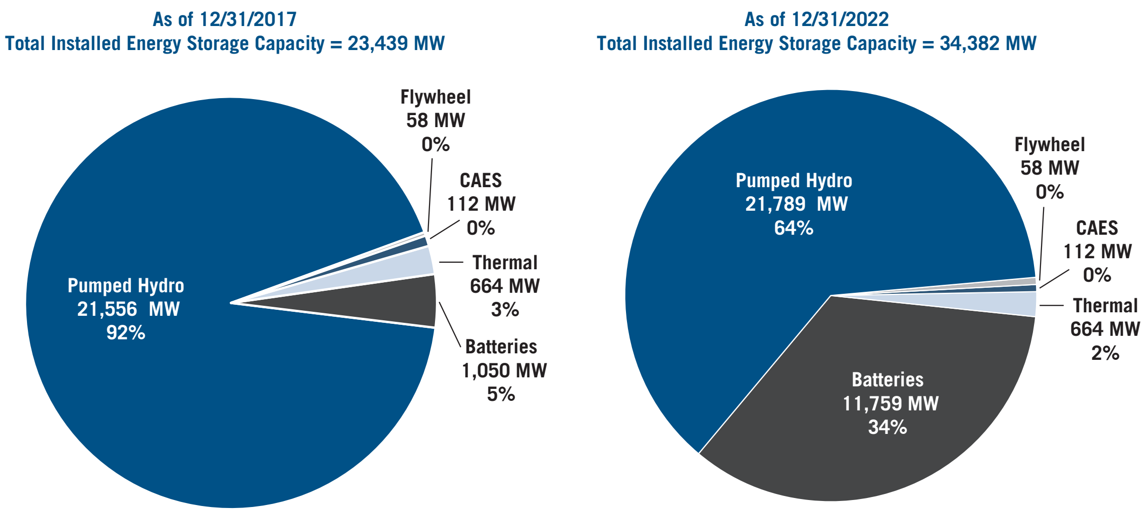
### Retirements

As of April 2023, 101,617 MW of capacity was scheduled to be retired from 2023 through 2027. Coal continues to lead retirements, accounting for 42% of the projected total. Coal retirements are expected to reach 10,852 MW in 2023, a 17% decline compared to the actual 13,092 retirements in 2022. Natural gas ranked second and fuel oil third in terms of projected retirements over the full five-year period, at 40% and 16%, respectively.

Natural gas retirements are expected to peak in 2024 at 18,593 MW; this would be the highest actual or projected annual retirement total of any fuel from 2018 through 2027. Wind and solar retirements re-

## Total Installed Energy Storage Capacity by Technology (MW)

U.S. ELECTRIC UTILITY AND NON-UTILITY




Sources: The Velocity Suite, Hitachi Energy; Wood Mackenzie Energy Storage Database; U.S. Department of Energy Sandia Energy Storage Dataset, EEI Energy Supply and Finance Department, March 2023

main minimal, together accounting for only a combined 0.05% of total projected retirements from 2023 through 2027. Nuclear retirements peaked in 2020, at 2,031 MW, with the shutdowns of the Duane Arnold Energy Center in Iowa (660 MW) and Indian Point Unit 2 in New York (1,371 MW). The Palisades Power Plant in Michigan (823 MW) was the only nuclear facility to retire in 2022 and accounted for all nuclear capacity retired. An additional 2,323 MW of nuclear capacity is expected to retire over the next three years due to the anticipated shutdown of the 2,323 MW Diablo Canyon Power Plant (CA) in stages between 2024 and 2025.

### Energy Storage

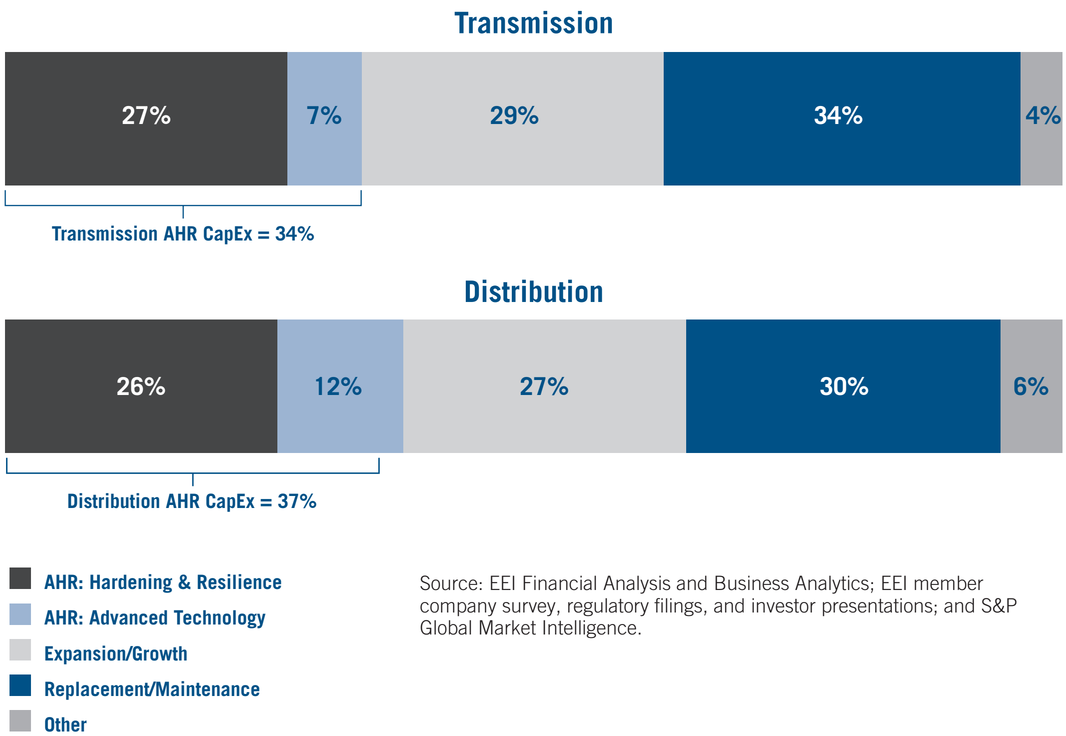
Energy storage continues to be a fast-growing area for the industry. At year-end 2022, utilities owned or operated 31,883 MW of storage capacity, or about 93% of all energy storage in the United States. Since 2017, total installed energy storage capacity nationwide owned or operated by utilities has increased 38%, from about 23,127 MW in 2017 to 31,883 MW in 2022.

Pumped hydro accounted for 68% of the total energy storage capacity owned by both U.S. investor-owned utilities and non-utilities, at 21,789 MW of capacity. Battery storage is the fastest-growing storage technology in terms of capacity, with total deployed capacity up approximately 1,020% from 2017 to 2022. Between 2017 and 2022, battery energy storage grew from 5% of total energy storage capacity to 34%.

The fast-paced growth of battery storage is likely to continue; 74,271 MW of battery storage capacity is expected to come online from 2023 through 2027, representing 83% of all incremental energy storage during this time period and becoming the dominant energy storage technology. Utilities will continue to lead battery storage deployment, accounting for 60,503 MW of the projected new battery storage capacity from 2023 through 2027.

Pumped hydro accounts for 16% of projected energy storage deployment from 2023 through 2027. Four rerate projects result in 267 MW capacity – Bear Swamp in Massachusetts (33 MW), Bad Creek

## Adaptation, Hardening, and Resilience (AHR) as Drivers of T&D Investment
### Based on 2022 Survey Results




Source: EEI Financial Analysis and Business Analytics; EEI member company survey, regulatory filings, and investor presentations; and S&P Global Market Intelligence.

in South Carolina (173 MW), Salina in Oklahoma (24 MW), and Cabin Creek in Colorado (37 MW). Two expansion projects account for 1,260 MW capacity – the Mineville Pumped Storage Project in New York (260 MW) and the Swan Lake North Hydro Pumped Storage Project (1,000 MW). The remaining announced projects are new constructions in the early stages of development.

The remaining 1% of new energy storage is compressed air energy storage at one project, the Rosamond CASE project in California at 500 MW. The project is expected to come online in 2024.

### Transmission and Distribution

EEI member companies are spending a significant and growing amount of resources on adaptation, hardening, and resilience (AHR) initiatives. In recent years, it is estimated that EEI's member companies have invested almost $30 billion per year in AHR for transmission and distribution infrastructure. Specific examples of AHR investments in the electric grid include undergrounding power lines, installing cement poles, and elevating or relocating transformers. AHR is increasingly becoming an important way for electric companies to fulfill their mission of supplying customers with reliable, affordable, and increasingly sustainable energy. Electric companies also are developing weather predictive services, risk modeling, fire spread modeling, deployment of sensors and high-definition cameras, communication networks, satellite data damage assessment, and other real or near real time situational awareness instruments that can help them better predict and prepare for extreme weather events and wildfires.

## Fuel Sources

### Net Generation and Electricity Sales

Electric power industry net generation in 2022 totaled 4,301,648 gigawatt hours (GWh), an increase of 3.5% versus 2021. Nationwide retail electricity sales increased 2.7%, showing gains across 45 states and the District of Columbia and rising for the second consecutive year after last year's 2.1% increase. The states with the largest year-to-year percentage increases in retail electricity sales in 2022 were North Dakota (+10.7%), New Mexico (+8.5%), Florida (+7.4%), and Oklahoma (+7.4%). Oregon (-1.3%), New Hampshire (-0.5%), Minnesota (-0.2%), Connecticut (-0.2%), and Massachusetts (-0.1%) were the few states where sales declined.

Total sales to commercial customers increased 3.4%, substantially above the 2.7% overall nationwide sales gain. This is the second consecutive annual increase for commercial sales after last year's 2.9% growth, indicating that business activity has continuously returned to normal following 2020's pandemic-related shutdowns. Almost every state experienced growth in commercial sales in 2022, with North Dakota (+10.7%) experiencing the largest percentage gain. The only states showing a decline were Connecticut (-1.5%) and New Hampshire (-0.6%).

Total electricity sales to industrial customers increased 0.7% year-to-year, producing gains in 31 states. The 2022 percentage increase was lower than 2021's 2.9%, which was likely driven by resumption and expansion of industrial activity after states relaxed their COVID-19 protocols. New Mexico (+15.2%) and Florida (+12.8%) had the highest percentage increases. While the District of Columbia produced the largest percentage increase in 2021, at 29%, it saw the largest percentage decrease in 2022, at -24.2%. Louisiana showed the largest sales gain in absolute terms, at 2,552 GWh, representing a 6.7% increase over 2021's total. Nineteen states – Alabama, California, Delaware, Idaho, Indiana, Kentucky, Maine, Minnesota, New Hampshire, New Jersey, New York, Oregon, Rhode Island, South Dakota, Texas, Utah, Vermont, Virginia, Washington – and the District of Columbia all experienced lower industrial sales compared to 2021's total; decreases ranged from 0.1% (Idaho) to 24.2% (District of Columbia).

Electricity sales to residential customers increased 3.5% in 2022, above last year's 0.8% gain. Texas (+10.7%) and North Dakota (+8.2%) were the states with the highest percentage growth in 2022. Texas also experienced the largest growth in absolute terms, at 16,583 GWh, followed by Florida, at 9,066 GWh. Forty-

## Fuel Sources for Net Electric Generation

U.S. ELECTRIC UTILITY AND NON-UTILITY

| | 2021r | 2022 |
|---|---|---|
| **Coal** | 21.6% | 19.3% |
| **Gas** | 38.0% | 39.3% |
| **Nuclear** | 18.7% | 17.9% |
| **Hydro** | 6.1% | 6.1% |
| **Renewables** | 14.7% | 16.5% |
| **Biomass** | 1.3% | 1.2% |
| **Geothermal** | 0.4% | 0.4% |
| **Solar** | 4.0% | 4.7% |
| **Wind** | 9.1% | 10.1% |
| **Other fuels** | 0.9% | 0.9% |
| **Total** | 100% | 100% |

r = revised

Note: Other fuels include: Pumped hydro, other gases, and diesel/fuel oil. Totals may not equal 100% due to rounding.

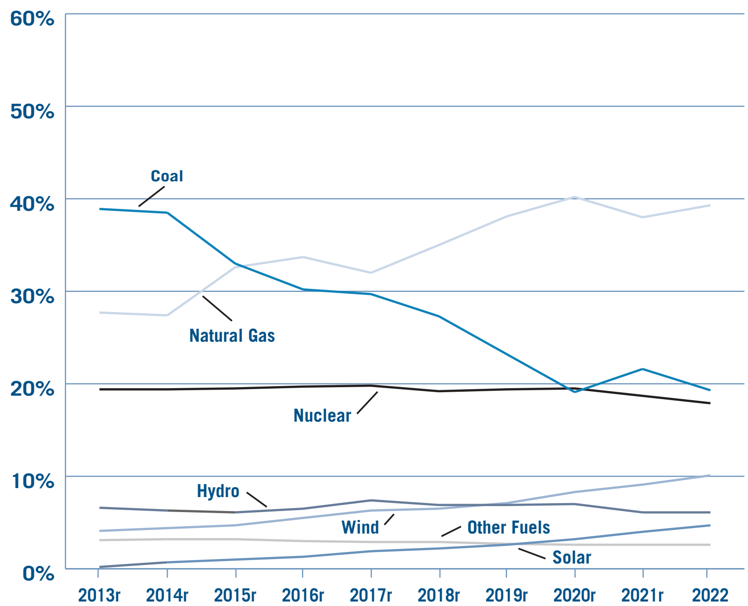
**U.S. Electric Utility:** Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

**Non-Utility Power Producer:** Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: U.S. Department of Energy, Energy Information Administration (EIA), EEI Energy Supply and Finance Department, April 2023

## Fuel Sources for Net Electric Generation (Percent of Total Electric Generation) 2013-2022

U.S. ELECTRIC UTILITY AND NON-UTILITY




r = revised

**U.S. Electric Utility:** Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

**Non-Utility Power Producer:** Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2023

two states saw residential electricity sales rise in 2022. Hawaii (-2.7%) and Michigan (-2.2%) had the largest percentage declines in residential electricity sales.

The variations in year-to-year residential sales trends across states may be due, in part, to the impact of differing protocols and mandates in the aftermath of COVID-19. States with residential electricity sales growth may have seen a continued increase in 2022 in the number of people working from home. Conversely, relatively fewer people may have worked from home in states with residential sales declines in 2022.

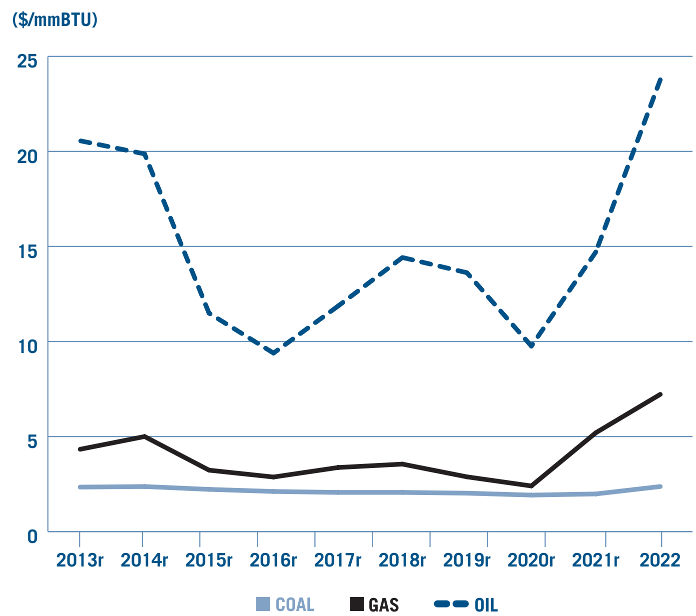
### Coal

Generation from coal-fired plants in 2022 was 7.7% below the 2021 total. Coal accounted for 19.3% of total electricity generation nationwide in 2022. Coal's 828,993 GWh of generation placed it second, behind natural gas, among the fuels that contributed to total nationwide generation. The coal fleet's capacity factor decreased from 49% in 2021 to 48% in 2022.

The average cost to produce electricity from coal increased 12.3%, from $33.04/MWh in 2021 to $37.11/MWh in 2022. A 19.7% increase in the average price of coal, from $1.98 per million British

## Average Cost of Fossil Fuels 2013–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY




r = revised

**U.S. Electric Utility:** Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

**Non-Utility Power Producer:** Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: Energy Information Administration (EIA), U.S. Department of Energy; EEI Energy Supply and Finance Department, April 2023

Thermal Units (MMBtu) in 2021 to $2.37 MMBtu in 2022, drove up the fuel cost component of coal generation. This increase was offset by a 6.3% decline in average operations and maintenance expenses, which dropped from $10.3/MWh in 2021 to $9.65/MWh in 2022. Because sharply higher natural gas fuel prices have made natural gas generation far more costly than coal, the more muted increase in coal generation costs preserved coal's place as the second-most expensive fuel for electricity generation in 2022 as it was in 2021.

Annual coal generation returned to its previous declining trend after a brief increase in 2021, mainly because of constrained coal supply.

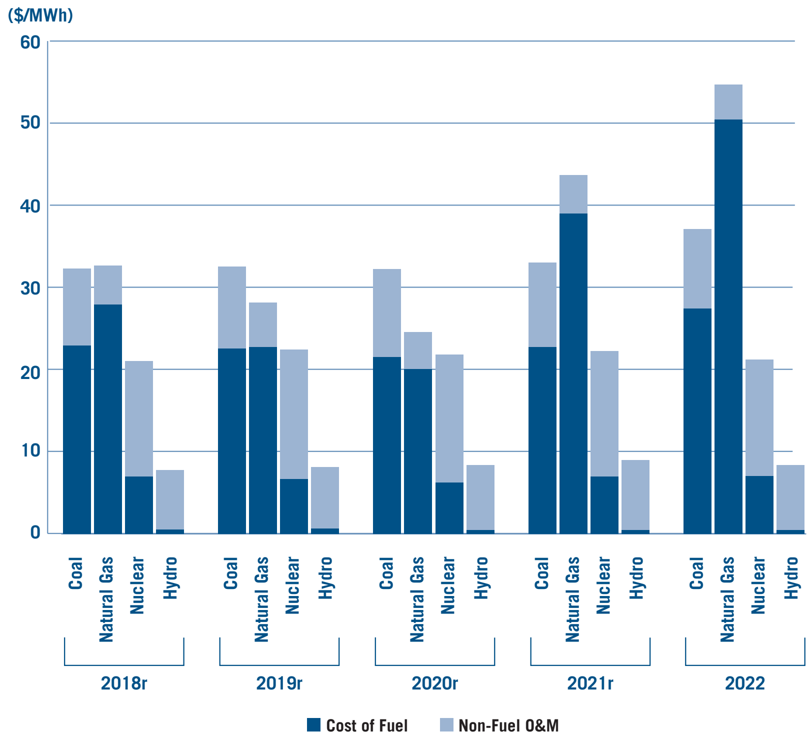
The decline in coal generation in 2022 was accompanied by a decrease in coal plants' average capacity factor along with a significant increase in coal capacity retirements compared to 2021. From 2018 through 2022, only 103 MW of new coal capacity came online compared to 59,437 MW of coal retirements. Another 42,365 MW of coal capacity is projected to retire from 2023 through 2027.

### Natural Gas

Natural gas powered 39.3% of 2022's total generation—more than

## Average Cost to Produce Electricity 2018–2022

U.S. ELECTRIC UTILITY AND NON-UTILITY




r = revised

Note: 2022 results are preliminary. Totals may reflect rounding.

**U.S. Electric Utility:** Owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. This includes investor-owned utilities, public power, and cooperatives.

**Non-Utility Power Producer:** Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Source: The Velocity Suite, Hitachi Energy, EEI Energy Supply and Finance Department, April 2023

any other single fuel type. That share increased more than one percentage point from its 2021 level, but it remains below the 40.2% of 2020. The average cost of natural gas for electricity generation rose dramatically, increasing 38.8%, from $5.20/MMBtu in 2021 to $7.22/MMBtu, in 2022, its highest level in recent history. As a result, the average cost to produce electricity from natural gas rose 25.3% in 2022 versus 2021 and was 47.6% higher than the average cost to produce electricity from coal.

### Renewables

The electric industry continues to add record amounts of renewable capacity. As a result, electric generation from carbon-free sources increased to 1,742,920 MWh in 2022, representing 40.5% of the electric power industry's total generation. Generation from all renewable sources was 971,383 MWh, or 22.6% of the total in 2022 compared with 864,432 MWh, or 20.8%, in 2021.

Conventional hydroelectric generation rose to 261,999 MWh, a 4.1% increase from 2021's 251,585 MWh. It accounted for 6.1% of electricity generation in 2022, the same as last year but down from 7.0% in 2020. Generation from wind power increased 15%, from 378,197 MWh in 2021 to 434,812 MWh in 2022 and accounted for 10.1% of 2022's total electricity generation. Solar generation increased 24.1%, from 164,423 MWh in 2021 to 204,111 MWh in 2022, reaching 4.7% of total electricity generation. Utility-scale solar accounted for 145,599 MWh, or 71.3%, of solar generation, an increase from 70.1% in 2021.

### Nuclear

Nuclear generation decreased 0.8% in 2022 and accounted for 17.9% of total electric power generation, down from 18.7% in 2021. The decline was due to reduced capacity resulting from nuclear plant retirements; 6,120 MW of nuclear capacity was retired from 2018 through 2022, with the retirement of 823 MW at the Palisades power plants in Michigan in 2022 the most recent. Another 2,323 MW is projected to be retired over the next five years through closure of the Diablo Canyon power plant in California. Nuclear power plants had an average capacity factor of 92.6% in 2022 compared to average capacity factors of 47.8% for coal and 36.7% for natural gas.

Nuclear fuel costs increased 0.7%, from $6.99/MWh in 2021 to $7.04/MWh in 2022. However, non-fuel operations and maintenance costs decreased 7.1%, from $15.26/MWh in 2021 to $14.18/MWh in 2022. As a result, the total cost to produce electricity from nuclear power declined 4.7%.

A total of 3,953 MW of nuclear capacity is expected to come online from 2023 through 2027. Two existing plants have planned expansions — 2,200 MW at Vogtle (GA) and 1,213 MW at Bellefonte (AL). At the same time, small modular nuclear reactors (SMRs) will begin to contribute to nuclear capacity increases with 540 MW from the NuScale Small Nuclear Modular Project (ID) expected to come online in 2024. Looking farther into the future, the Tennessee Valley Authority announced an agreement with GE-Hitachi to support the potential deployment of a BWRX-300 SMR at its Clinch River site. In addition, X-energy announced the construction of a TRISO-X Fuel Fabrication Facility (FT3), North America's first commercial-scale facility dedicated to fueling High-Assay Low-Enriched Uranium (HALEU)-based reactors, that is expected to be operational by 2025.

# Industry Financial Performance

## Income Statement

- Energy Operating Revenues rose 15.8% versus last year. The strong gain was mostly a result of higher fuel commodity prices, which are mostly passed through under rate regulation and do not increase utility profits. Nationwide electricity generation increased 2.7% as residential and commercial sales each gained more than 3% year-to-year. Industrial sales were flat after rising more than 4% in 2021. Driven higher by fuel costs, the average retail price of electricity nationwide increased 12.5%, according to EIA data. By contrast, the average retail price nationwide rose only 7.7% over the entire 2010 through 2020 10-year period. Almost all 44 utilities included in EEI's industry consolidated data reported higher revenue in 2022.

- Inflation pressures drove generation costs sharply higher for the second straight year. The cost of natural gas for electric generation jumped more than 30% while the cost of coal rose about 20%, based on EIA data. As a result, the industry's consolidated Total Electric Generation Cost climbed 29.2% year-to-year while Gas Cost increased 54.3%. These two line items combined to drive the industry's Total Energy Operating Expenses up 33.3%. Slightly less than half the utilities tracked by EEI separately disclose Electric Fuel Expense and Cost of Purchased Power. Based on that data, the industry's aggregate reported Electric Fuel Expense rose 56.5% while Cost of Purchased Power increased 31.1%.

- Operations and Maintenance (O&M) costs rose 7.9% after gaining only 1.0% to 1.5% annually from 2018 through 2020. Utilities' O&M spending is benefitting from smart-grid investment productivity and the industry worked hard to constrain O&M expenses during the pandemic to address revenue declines. Yet O&M costs are also driven by essential reliability needs. Most utilities showed a year-to-year increase in O&M costs for 2022.

- Depreciation & Amortization (D&A) expenses rose 7.5%. This metric increased for 39 of the 44 constituent companies, reflecting the industry's ongoing widespread and diverse investments in new clean generation, transmission, distribution and grid modernization.

- Most of the $4.9 billion, or 23.5%, year-to-year jump in Other Operating Expenses reflects accounting for non-utility costs at one large company. Only six other utilities made small contributions to the industry total. None of these reflect meaningful industry-wide trends.

- Operating Income rose $5.0 billion, or 7.2%, versus 2021. Higher Energy Operating Revenues were offset by sharply higher generation and gas costs while Operations and Maintenance expenses and Depreciation and Amortization expenses also increased. Operating Income rose for 28 companies and declined for 16.

- Total Other Recurring Revenue declined $4.1 billion, or 33.9%, due almost entirely to a $4.3 billion decline in Other Revenue. This in turn was driven mostly by a $3.75 billion decline at just one of the 44 underlying utilities and does not reflect a broad industry trend.

- Total Non-Recurring Revenue was slightly positive after 2021's small deficit, but only a few utilities contributed to the 2022 total. 2021's deficit resulted primarily from the sale of impaired fossil generation assets at one utility. Activity in each year was insignificant in terms of broad industry trends.

- Interest Expense rose by 3.4%, reflecting in part the rise in both short- and long-term interest rates during 2022. However, this line item increased for 35 of the 44 underlying companies and rose markedly for some utilities.

- Net Income Before Taxes increased 6.4%, while Net Income rose 3.1%. These figures are driven by the industry's largest companies and mask a wide variation in company-specific results. Pre-Tax Income rose at 24 companies and declined at 20. Net Income rose at 20 and fell at 24. The year-to-year change in both metrics showed considerable variation across companies.

- The industry's aggregate Common Dividend payments rose 3.1% versus 2021, although the average percentage dividend increase was 5.2%. Nearly all utilities raised their dividend in 2022. The industry's reliable stock dividends continue to offer a welcome source of income for savings-oriented investors.

## Consolidated Income Statement

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

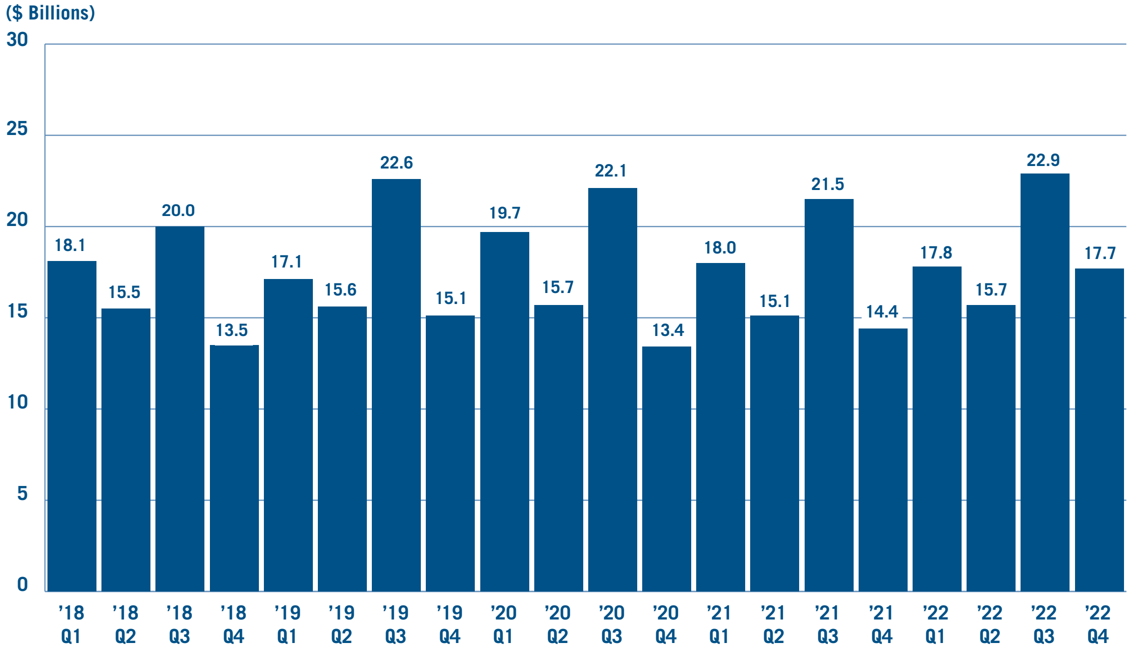
| | 12 Months Ended | | |
|---|---|---|---|
| **($ Millions)** | **12/31/2022** | **12/31/2021r** | **% Change** |
| **Energy Operating Revenues** | $424,428 | $366,615 | 15.8% |
| **Energy Operating Expenses** | | | |
| Total Electrical Generation Cost | 112,572 | 87,125 | 29.2% |
| Gas Cost | 26,083 | 16,910 | 54.3% |
| **Total Energy Operating Expenses** | **138,655** | **104,035** | **33.3%** |
| **Revenues less energy operating expenses** | **285,773** | **262,580** | **8.8%** |
| **Other Operating Expenses** | | | |
| Operations & maintenance | 101,242 | 93,854 | 7.9% |
| Depreciation & Amortization | 61,458 | 57,193 | 7.5% |
| Taxes (not income) - Total | 23,304 | 21,647 | 7.7% |
| Other Operating Expenses | 25,746 | 20,846 | 23.5% |
| **Total Operating Expenses** | **350,405** | **297,574** | **17.8%** |
| **Operating Income** | **74,023** | **69,041** | **7.2%** |
| **Other Recurring Revenue** | | | |
| Partnership Income | 2,588 | 2,621 | (1.3%) |
| Allowance for Equity Funds Used for Construction | 2,274 | 2,085 | 9.1% |
| Other Revenue | 3,191 | 7,476 | (57.3%) |
| **Total Other Recurring Revenue** | **8,052** | **12,182** | **(33.9%)** |
| **Non-Recurring Revenue** | | | |
| Gain on Sale of Assets | 510 | (1,902) | (126.8%) |
| Other Non-Recurring Revenue | 341 | 471 | (27.6%) |
| **Total Non-Recurring Revenue** | **( 851** | **(1,430)** | **(159.5%)** |
| Interest expense | 26,987 | 26,112 | 3.4% |
| Other expenses | 822 | 385 | 113.3% |
| Asset Writedowns | 2,985 | 1,199 | 148.9% |
| Other Non-Recurring Expenses | 4,366 | 7,221 | (39.5%) |
| Total Non-Recurring Expenses | 7,351 | 8,421 | (12.7%) |
| **Net Income Before Taxes** | **47,766** | **44,874** | **6.4%** |
| Provision for Taxes | 3,045 | 3,390 | (10.2%) |
| Dividends on Preferred Stock of Subsidiary | - | - | NM |
| Other Minority Interest Expense | - | - | NM |
| Minority Interest Expense | - | - | NM |
| Trust Preferred Security Payments | - | - | NM |
| Other After-tax Items | - | - | NM |
| Total Minority Interest and Other After-tax Items | - | - | NM |
| **Net Income Before Extraordinary Items** | **44,721** | **41,485** | **7.8%** |
| Discontinued Operations | (1,151) | 793 | (245.2%) |
| Change in Accounting Principles | - | - | NM |
| Early Retirement of Debt | - | - | NM |
| Other Extraordinary Items | - | - | NM |
| Total Extraordinary Items | (1,151) | 793 | (245.2%) |
| **Net Income** | **43,570** | **42,277** | **3.1%** |
| Preferred Dividends Declared | 508 | 573 | (11.3%) |
| Other Preferred Dividends after Net Income | 2 | 2 | 0.0% |
| Other Changes to Net Income | (4) | (2) | 100.0% |
| Net Income Attributable to Noncontrolling Interests | (513) | (527) | NA |
| **Net Income Available to Common** | **43,569** | **42,227** | **3.2%** |
| **Common Dividends** | **31,016** | **30,075** | **3.1%** |

r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

## Quarterly Net Operating Income

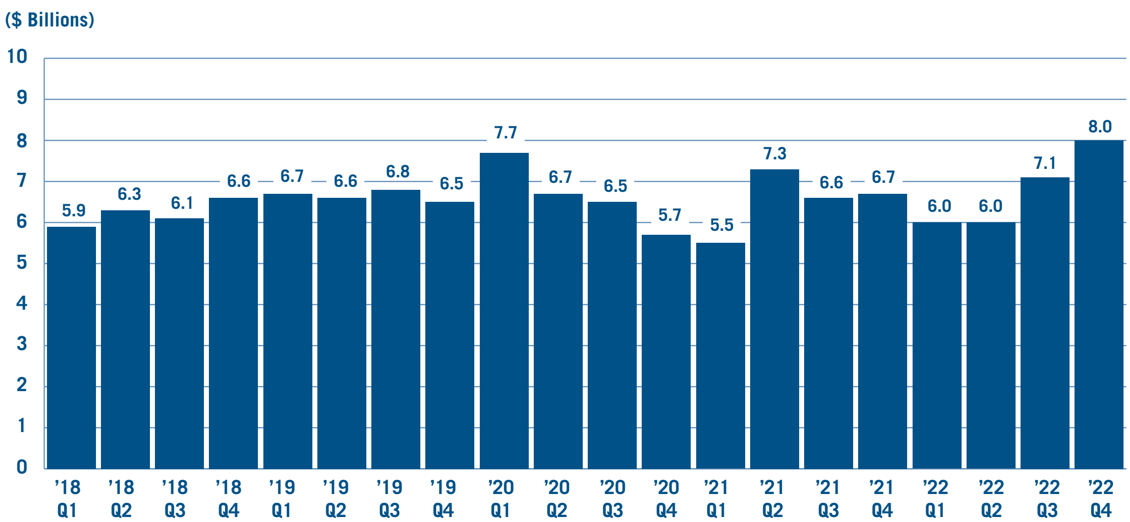
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: S&P Global Market Intelligence and EEI Finance Department.

## Quarterly Interest Expense

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: S&P Global Market Intelligence and EEI Finance Department.

## Individual Non-Recurring and Extraordinary Items 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| ($ Millions) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021r | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| Net Gain (Loss) on Sale of Assets | 414 | 996 | 789 | 767 | 1,012 | 5,272 | 3,049 | **(398)** | (1,902) | 510 |
| Other Non-Recurring Revenue | 78 | 296 | (4) | 888 | 493 | 131 | 117 | – | 471 | 341 |
| **Total Non-Recurring Revenue** | **492** | **1,292** | **785** | **1,655** | **1,505** | **5,403** | **3,167** | **(398)** | **(1,430)** | **851** |
| Asset Writedowns | (4,276) | (8,762) | (5,189) | (17,487) | (4,166) | (4,121) | (3,470) | 6,704 | 1,199 | 2,985 |
| Other Non-Recurring Charges | (3,510) | (2,675) | (1,764) | (3,109) | (5,630) | (17,841) | (13,034) | 8,504 | 7,221 | 4,366 |
| **Total Non-Recurring Charges** | **(7,786)** | **(11,437)** | **(6,953)** | **(20,596)** | **(9,796)** | **(21,962)** | **(16,504)** | **15,208** | **8,421** | **7,351** |
| Discontinued Operations | (88) | 295 | (1,148) | (732) | (1,554) | 602 | 1,243 | 17 | 793 | (1,151) |
| Change in Accounting Principles | – | – | – | – | – | – | – | – | – | – |
| Early Retirement of Debt | – | – | – | – | – | – | – | – | – | – |
| Other Extraordinary Items | – | – | – | – | – | – | – | – | – | – |
| **Total Extraordinary Items** | **(88)** | **295** | **(1,148)** | **(732)** | **(1,554)** | **602** | **1,243** | **17** | **793** | **(1,151)** |
| **Total Non-Recurring and Extraordinary Items** | **(7,381)** | **(9,850)** | **(7,316)** | **(19,674)** | **(9,844)** | **(15,957)** | **(12,094)** | **(15,589)** | **(9,058)** | **(7,651)** |

r = revised    Note: Figures represent net industry totals. Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

## Top Net Non-Recurring and Extraordinary Gains (Losses) 2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

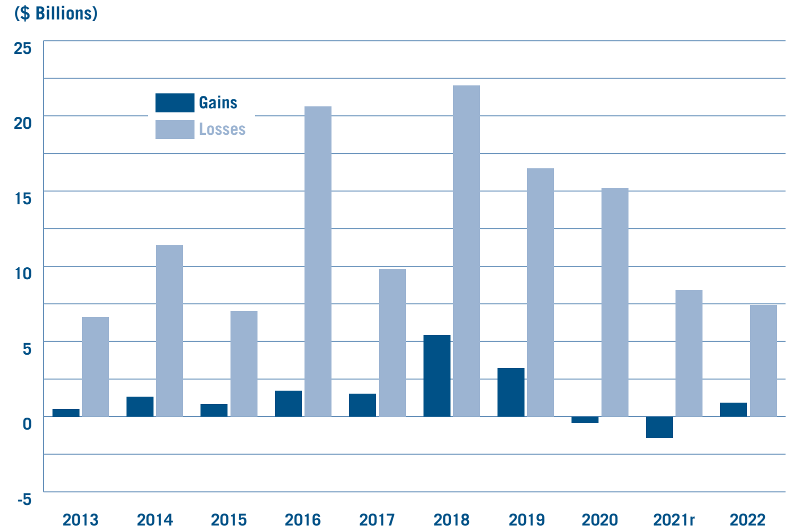
($ Millions)

| Company | Gains | Losses | Net Total |
|---|---|---|---|
| **Dominion Energy** | (404) | 2,377 | 2,781 |
| **Edison International** | 10 | 1,581 | 1,571 |
| **PG&E Corp** | – | 1,322 | 1,322 |
| **Duke Energy** | 22 | 499 | 477 |
| **Southern Company** | 57 | 434 | 377 |
| **CenterPoint Energy** | 303 | – | 303 |
| **OGE Energy** | 282 | – | 282 |
| **Sempra Energy** | – | 259 | 259 |
| **American Electric Power** | (210) | 49 | 259 |
| **FirstEnergy** | – | 171 | 171 |

Source: S&P Global Market Intelligence and EEI Finance Department.

## Aggregate Non-Recurring and Extraordinary Items 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES



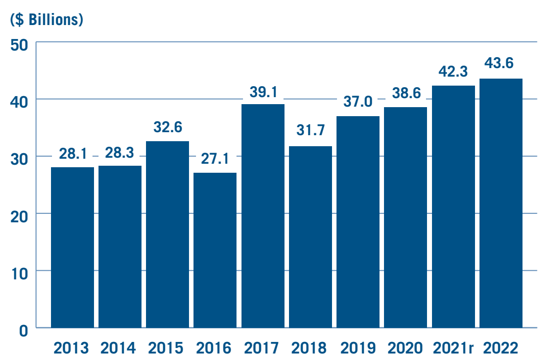

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021r | 2022 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gains** | 0.5 | 1.3 | 0.8 | 1.7 | 1.5 | 5.4 | 3.2 | (0.4) | (1.4) | 0.9 | 13.3 |
| **Losses** | 6.6 | 11.4 | 7.0 | 20.6 | 9.8 | 22.0 | 16.5 | 15.2 | 8.4 | 7.4 | 124.9 |
| **Total** | **(6.2)** | **(10.1)** | **(6.2)** | **(18.9)** | **(8.3)** | **(16.6)** | **(13.3)** | **(15.6)** | **(9.9)** | **(6.5)** | **(111.6)** |

r = revised Note: Totals may reflect rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

## Net Income 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

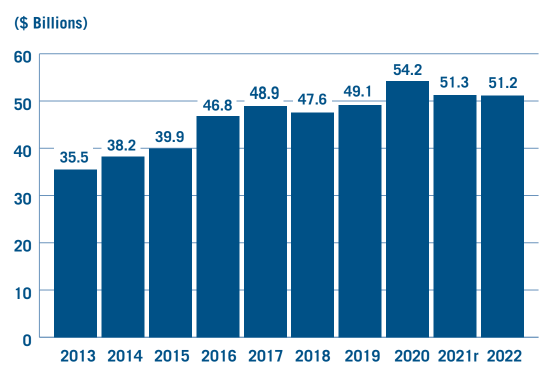



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

## Net Income Before Non-Recurring and Extraordinary Items 2013-2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

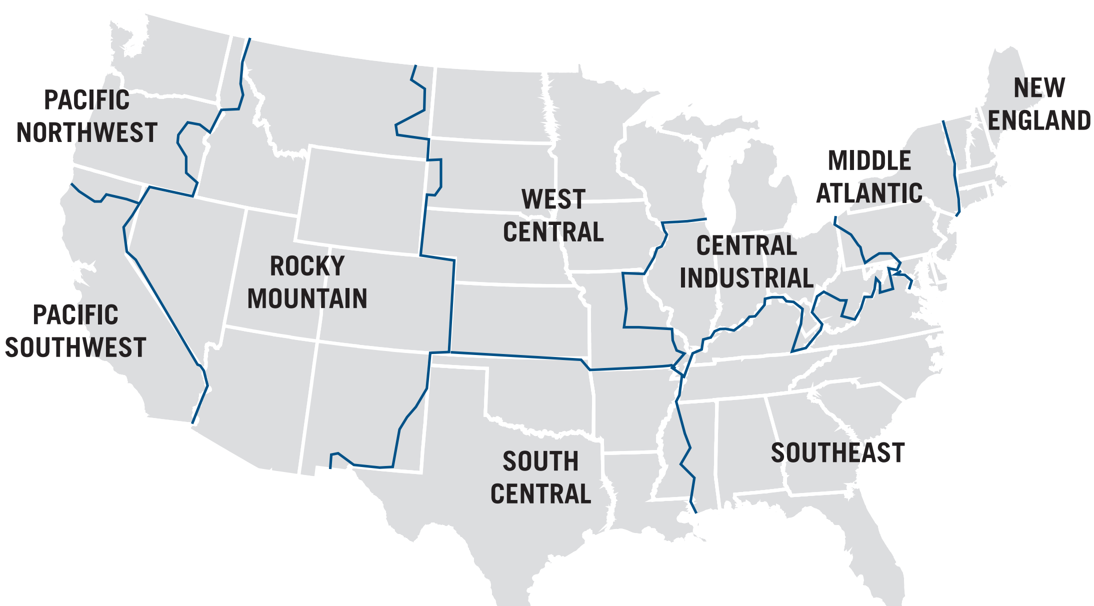
## U.S. Electric Output (GWh)
### Periods Ending December 31

| Region | 2022 | 2021 | % Change |
|---|---|---|---|
| New England | 115,781 | 115,930 | (0.1%) |
| Mid-Atlantic | 419,466 | 418,296 | 0.3% |
| Central Industrial | 657,622 | 651,041 | 1.0% |
| West Central | 341,836 | 335,136 | 2.0% |
| Southeast | 1,036,554 | 1,014,838 | 2.1% |
| South Central | 840,535 | 778,018 | 8.0% |
| Rocky Mountain | 296,141 | 292,947 | 1.1% |
| Pacific Northwest | 161,364 | 158,170 | 2.0% |
| Pacific Southwest | 273,602 | 268,259 | 2.0% |
| **Total United States** | **4,142,901** | **4,032,635** | **2.7%** |

Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii.

Source: EEI Business Analytics.

## EEI U.S. Electric Output – Regions




Source: EEI Business Analytics.

## U.S. Weather
### January – December 2022

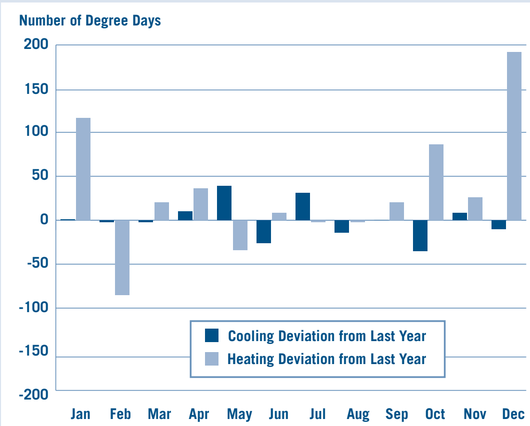
| | Total | Dev from Norm | % Change | Dev from Last Year | % Change |
|---|---|---|---|---|---|
| **Cooling Degree Days** | | | | | |
| New England | 651 | 234 | 56% | (4) | (1%) |
| Mid-Atlantic | 856 | 200 | 30% | (56) | (6%) |
| East North Central | 827 | 119 | 17% | (141) | (15%) |
| West North Central | 1,090 | 162 | 17% | (27) | (2%) |
| South Atlantic | 2,177 | 213 | 11% | (50) | (2%) |
| East South Central | 1,725 | 177 | 11% | 41 | 2% |
| West South Central | 2,918 | 469 | 19% | 270 | 10% |
| Mountain | 1,384 | 141 | 11% | (19) | (1%) |
| Pacific | 975 | 271 | 38% | 69 | 8% |
| **United States** | **1,440** | **224** | **18%** | **0** | **0%** |
| **Heating Degree Days** | | | | | |
| New England | 6,107 | (504) | (8%) | 274 | 5% |
| Mid-Atlantic | 5,554 | (357) | (6%) | 456 | 9% |
| East North Central | 6,352 | (145) | (2%) | 605 | 11% |
| West North Central | 6,947 | 197 | 3% | 895 | 15% |
| South Atlantic | 2,673 | (180) | (6%) | 220 | 9% |
| East South Central | 3,489 | (115) | (3%) | 334 | 11% |
| West South Central | 2,366 | 79 | 3% | 402 | 20% |
| Mountain | 5,207 | (2) | (0%) | 507 | 11% |
| Pacific | 3,124 | (104) | (3%) | 24 | 1% |
| **United States** | **4,392** | **(132)** | **(3%)** | **380** | **9%** |

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65 degrees Fahrenheit is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration, National Weather Service, Climate Prediction Center.

## 2022 Weather Compared to 2021

AS MEASURED BY DEVIATIONS BETWEEN THE TWO YEARS




Source: National Oceanic and Atmospheric Administration and National Weather Service.

| | Cooling Deviation From Last Year | Heating Deviation From Last Year |
|---|---|---|
| **Jan** | 1 | 116 |
| **Feb** | (2) | (85) |
| **Mar** | (2) | 20 |
| **Apr** | 10 | 36 |
| **May** | 39 | (34) |
| **Jun** | (26) | 8 |
| **Jul** | 31 | (2) |
| **Aug** | (14) | (2) |
| **Sep** | 0 | 20 |
| **Oct** | (35) | 86 |
| **Nov** | 8 | 26 |
| **Dec** | (10) | 191 |
| **Total** | **0** | **380** |

## Heating and Cooling Degree Days and Percent Changes

### January—December 2022

| | COOLING DEGREE DAYS | | | HEATING DEGREE DAYS | | | PERCENTAGE CHANGE | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total | Deviation From Norm | Deviation From Last Yr | Total | Deviation From Norm | Deviation From Last Yr | Cooling Degree Change From Norm | Cooling Degree Change From Last Yr | Heating Degree Change From Norm | Heating Degree Change From Last Yr |
| Jan | 5 | (4) | 1 | 927 | 10 | 116 | (44.4%) | 25.0% | 1.1% | 14.3% |
| Feb | 8 | 0 | (2) | 726 | (6) | (85) | 0.0% | (20.0%) | (0.8%) | (10.5%) |
| Mar | 18 | 0 | (2) | 539 | (54) | 20 | 0.0% | (10.0%) | (9.1%) | 3.9% |
| **First Quarter** | **31** | **(4)** | **(3)** | **2,192** | **(50)** | **51** | **(11.4%)** | **(8.8%)** | **(2.2%)** | **2.4%** |
| Apr | 44 | 14 | 10 | 357 | 12 | 36 | 46.7% | 29.4% | 3.5% | 11.2% |
| May | 140 | 43 | 39 | 127 | (32) | (34) | 44.3% | 38.6% | (20.1%) | (21.1%) |
| Jun | 249 | 36 | (26) | 27 | (12) | 8 | 16.9% | (9.5%) | (30.8%) | 42.1% |
| **Second Quarter** | **433** | **93** | **23** | **511** | **(32)** | **10** | **27.4%** | **5.6%** | **(5.9%)** | **2.0%** |
| Jul | 373 | 52 | 31 | 3 | (6) | (2) | 16.2% | 9.1% | (66.7%) | (40.0%) |
| Aug | 340 | 50 | (14) | 4 | (11) | (2) | 17.2% | (4.0%) | (73.3%) | (33.3%) |
| Sep | 190 | 35 | 0 | 59 | (18) | 20 | 22.6% | 0.0% | (23.4%) | 51.3% |
| **Third Quarter** | **903** | **137** | **17** | **66** | **(35)** | **16** | **17.9%** | **1.9%** | **(34.7%)** | **32.0%** |
| Oct | 43 | (10) | (35) | 272 | (10) | 86 | (18.9%) | (44.9%) | (3.5%) | 46.2% |
| Nov | 20 | 5 | 8 | 537 | (2) | 26 | 33.3% | 66.7% | (0.4%) | 5.1% |
| Dec | 10 | 3 | (10) | 814 | (3) | 191 | 42.9% | (50.0%) | (0.4%) | 30.7% |
| **Fourth Quarter** | **73** | **(2)** | **(37)** | **1,623** | **(15)** | **303** | **(2.7%)** | **(33.6%)** | **(0.9%)** | **23.0%** |
| **Full Year** | **1,440** | **224** | **0** | **4,392** | **(132)** | **380** | **18.4%** | **0.0%** | **(2.9%)** | **9.5%** |

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Heating Degree Days Percentage Change from Historical Norm** | (0.6) | 1.1 | (9.1) | (14.8) | (14.2) | (4.2) | (4.4) | (11.9) | (11.3) | (2.9) |
| **Cooling Degree Days Percentage Change from Historical Norm** | 10.9 | 5.8 | 19.2 | 29.4 | 16.0 | 26.4 | 20.3 | 21.1 | 18.3 | 18.4 |

A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. National averages are population weighted.

Source: National Oceanic and Atmospheric Administration and National Weather Service.

## Balance Sheet

- Economic growth slowed in 2022 after 2021's strong post-pandemic rebound. Real gross domestic product (GDP) posted negative readings in 2022's first half — at -1.6% in Q1 and -0.6% in Q2 — spurring widespread debate over whether the U.S. had officially entered a recession. Growth recovered in the year's second half as real GDP gained 3.2% in Q3 and 2.6% in Q4.

- As in 2021, inflation remained well above the U.S. Federal Reserve's (Fed) 2% target. The headline CPI posted monthly readings of 7% to 8% through November and over 6% in December. While the Fed held short-term rates at zero during 2021 to support the post-Covid recovery, in 2022 it raised rates seven times to a 4.25% to 4.50% range at year-end. As a result, short-term corporate borrowing costs reached levels not seen since before the 2008/2009 financial crisis.

- Bond yields climbed steadily but remained far below levels associated with high inflation in previous inflation cycles. Bond investors continued to see inflation as a short-term effect of strained supply chains contending with the post-Covid global economic reopening. The 10-year Treasury yield entered 2022 at 1.6% and ended the year at just 3.9%. Investment-grade corporates (Moody's Baa rating) could borrow long-term for 5% to 6% throughout 2022's second half, even with inflation above 7%.

- The industry's financial condition remained strong in 2022. The multi-year trend toward increased state-regulated utility operations continued, along with leverage appropriate for a lower risk profile. The industry's balance sheet leverage, in aggregate, increased slightly. However, aggregate figures convey only broad, long-term trends and emphasize large utility holding companies. Balance sheet structures vary widely across the industry. Leverage increased more than one percentage point at 18 companies. Leverage was reduced by more than one percentage point at 14 companies and was largely unchanged at the remaining 12 companies.

- The industry's consolidated total debt rose in 2022, a natural consequence of financing the aggressive build-out of clean-energy infrastructure. For the first time in years, rising interest rates meaningfully increased borrowing costs. Nevertheless, most companies managed balance sheet ratios and cash flows to maintain investment-grade credit ratings. Long-term debt increased at 32 utilities and declined at 12. The three largest instances where debt declined were associated with strategic repositioning. Balance sheet management produced scattered smaller debt reductions. Short-term debt rose at 28 companies, decreased at 12 and was unchanged (at zero each year) at four.

- Common equity issuance remained subdued, following three active years from 2018 through 2020. Many utilities sought to fund capex without equity dilution, in some cases with proceeds from asset sales. Just seven large utilities accounted for 80% of the industry's $11.0 billion total; four raised $1 billion to $2 billion during the year while three issued anywhere from $600 million to $1 billion. Another 17 companies issued equity in smaller amounts. Thirty utilities reported equity issuance in 2021. Issuance was strong in both 2020 and 2019 as companies augmented balance sheets and addressed the impact of tax reform. Equity issuance was also strong in 2018 as utilities took advantage of high price-earnings ratios and welcoming capital markets to fund capex and offset debt issuance.

- Property, plant and equipment in service (PPE in Service, net) rose 4.4% from year-end 2021 and 7.5% over the level at year-end 2020. This metric grew at nearly all 44 utilities which constitute EEI's consolidated data. Such broad growth indicates the size and scope of the industry's build-out of new renewable generation, new transmission, reliability-related infrastructure and other capital projects related to the nation's clean energy transition. Construction work in progress (CWIP), a component of the PPE in Service total, jumped nearly 21% over the year-end 2021 total and more than 27% from year-end 2020. CWIP accounts for capital investment in utility infrastructure still under construction and not yet in service. The accelerating

## Consolidated Balance Sheet

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| ($ Millions) | 12/31/2022 | 12/31/2021r | % Change | $ Change |
|---|---|---|---|---|
| PP&E in service, gross | 1,803,608 | 1,709,378 | 5.5% | 94,230 |
| Accumulated depreciation | 517,398 | 488,289 | 6.0% | 29,109 |
| PP&E in service, net | 1,286,210 | 1,221,089 | 5.3% | 65,121 |
| Construction work in progress | 103,931 | 85,777 | 21.2% | 18,154 |
| Net nuclear fuel | 12,933 | 12,957 | (0.2%) | (24) |
| Other property | 15,315 | 15,873 | (3.5%) | (558) |
| PP&E, net | 1,418,389 | 1,335,697 | 6.2% | 82,692 |
| Cash & cash equivalents | 13,378 | 17,330 | (22.8%) | (3,952) |
| Accounts receivable | 56,653 | 46,241 | 22.5% | 10,412 |
| Inventories | 29,569 | 23,844 | 24.0% | 5,725 |
| Other current assets | 81,301 | 70,443 | 15.4% | 10,859 |
| Total current assets | 180,901 | 157,857 | 14.6% | 23,044 |
| Total investments | 109,004 | 120,117 | (9.3%) | (11,114) |
| Other assets | 310,526 | 326,970 | (5.0%) | (16,444) |
| **Total Assets** | **2,018,819** | **1,940,641** | **4.0%** | **78,179** |
| Common equity | 539,825 | 526,137 | 2.6% | 13,688 |
| Preferred equity | 10,071 | 10,870 | (7.4%) | (799) |
| Noncontrolling interests | 28,036 | 25,939 | 8.1% | 2,097 |
| Total equity | 577,931 | 562,945 | 2.7% | 14,986 |
| Short-term debt | 49,672 | 39,754 | 24.9% | 9,917 |
| Current portion of long-term debt | 50,729 | 36,085 | 40.6% | 14,643 |
| Short-term and current long-term debt | 100,400 | 75,840 | 32.4% | 24,561 |
| Accounts payable | 91,703 | 77,408 | 18.5% | 14,294 |
| Other current liabilities | 60,594 | 60,348 | 0.4% | 246 |
| Current liabilities | 252,697 | 213,596 | 18.3% | 39,100 |
| Deferred taxes | 113,287 | 109,099 | 3.8% | 4,188 |
| Non-current portion of long-term debt | 740,215 | 694,027 | 6.7% | 46,188 |
| Other liabilities | 333,109 | 358,360 | (7.0%) | (25,251) |
| Total liabilities | 1,439,308 | 1,375,082 | 4.7% | 64,226 |
| Subsidiary preferred | 421 | 712 | (40.9%) | (291) |
| Other mezzanine | 1,159 | 1,901 | (39.0%) | (742) |
| Total mezzanine level | 1,580 | 2,613 | (39.5%) | (1,033) |
| **Total Liabilities and Owner's Equity** | **2,018,819** | **1,940,641** | **4.0%** | **78,179** |

r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

## Capitalization Structure

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| Capitalization Structure ($M) | 12/31/2022 | 12/31/2021r | 12/31/2020 |
|---|---|---|---|
| Common Equity | 539,825 | 526,137 | 494,872 |
| Noncontrolling Interests & Preferred Equity | 38,106 | 36,808 | 42,068 |
| Long-term Debt (current & non-current)* | 790,944 | 730,112 | 695,361 |
| **Total** | **1,368,875** | **1,293,058** | **1,232,301** |
| | | | |
| Common Equity % | 39.4% | 40.7% | 40.2% |
| Noncontrolling Interests & Preferred Equity % | 2.8% | 2.8% | 3.4% |
| Long-Term Debt (current & non-current)* % | 57.8% | 56.5% | 56.8% |
| **Total** | **100.0%** | **100.0%** | **100.0%** |

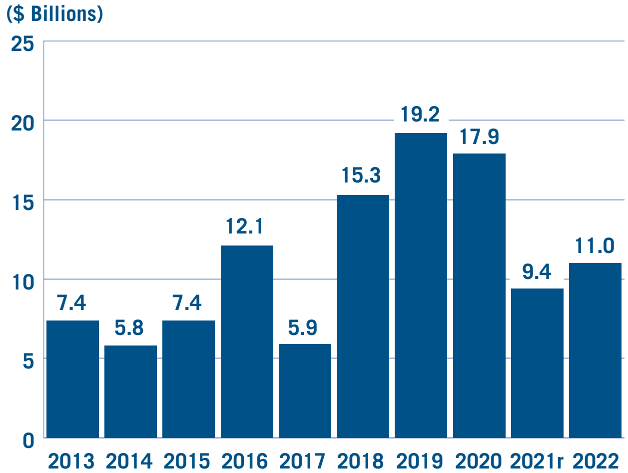
r = revised
Long-term debt not adjusted for (i.e., includes) securitization bonds.
Source: S&P Global Market Intelligence and EEI Finance Department.

growth in CWIP offers another view of the industry's rising clean energy capex.

- The debt-to-capitalization ratio by category data shows the dominance of state-regulated operations in the industry. Companies in EEI's "Regulated" group represent 36 of the 44 parent level companies tracked by EEI. The remaining eight constitute the "Mostly Regulated" group.
- The tendency toward slightly higher balance sheet leverage at the consolidated industry level is not evident across individual company moves. In fact, 13 of the 36 "Regulated" companies reduced leverage in 2022 while 14 increased leverage and 9 showed no meaningful change. Leverage increased at four of the eight "Mostly Regulated" companies, declined at one and was unchanged at three.
- The 3.5 percentage point jump in long-term debt as a percent of total capitalization in the Mostly Regulated group was driven largely by Exelon's separation of its regulated and competitive businesses in 2022 and the large resulting increase in leverage at the restructured Exelon.
- The dispersion across companies in both categories — with some showing higher, some lower and others no change in leverage — indicates why individual company strategies are as meaningful as consolidated totals when assessing industry trends.
- Regulated companies as a group continued to report higher balance sheet leverage than their Mostly Regulated peers. This is to be expected given their lower business risk profile.

## Proceeds from Issuance of Common Equity 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

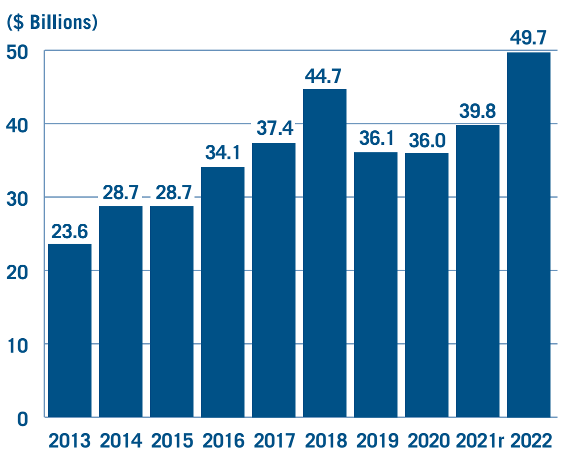



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

## Short-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

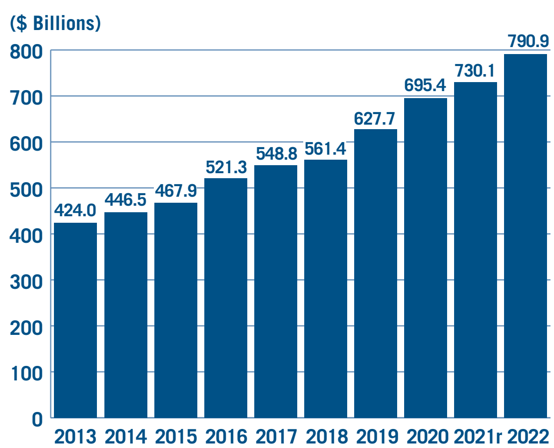



r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

## Long-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




r = revised

Source: S&P Global Market Intelligence and EEI Finance Department.

## Debt-to-Cap Ratio by Category 2022 vs. 2021r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| | Regulated | | Mostly Regulated | | Total Industry | |
|---|---|---|---|---|---|---|
| | Number | % | Number | % | Number | % |
| Lower | 13 | 36.1% | 1 | 12.5% | 14 | 31.8% |
| No Change* | 9 | 25.0% | 3 | 37.5% | 12 | 27.3% |
| Higher | 14 | 38.9% | 4 | 50.0% | 18 | 40.9% |
| **Total** | **36** | **100.0%** | **8** | **100.0%** | **44** | **100.0%** |

*No change defined as less than 1.0%
Note: December 31, 2022 vs. December 31, 2021. Refer to page v for category descriptions.
Source: S&P Global Market Intelligence and EEI Finance Department.

## Capitalization Structure by Category 2022 vs. 2021r

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| | Regulated | | | Mostly Regulated | | |
|---|---|---|---|---|---|---|
| | 2022 | 2021r | Change | 2022 | 2021r | Change |
| Common Equity ($M) | 388,279 | 367,806 | 20,473 | 151,546 | 158,331 | (6,786) |
| Total Preferred Equity | 22,734 | 21,221 | 1,513 | 15,372 | 15,587 | (215) |
| Long-term Debt (current & non-current)* | 603,220 | 560,191 | 43,028 | 187,724 | 169,921 | 17,803 |
| Total Capitalization | 1,014,233 | 949,218 | 65,015 | 354,642 | 343,839 | 10,803 |
| Common Equity % | 38.3% | 38.7% | -0.5% | 42.7% | 46.0% | -3.3% |
| Preferred Equity % | 2.2% | 2.2% | 0.0% | 4.3% | 4.5% | -0.2% |
| Long-Term Debt % | 59.5% | 59.0% | 0.5% | 52.9% | 49.4% | 3.5% |
| **Total** | **100.0%** | **100.0%** | — | **100.0%** | **100.0%** | — |

r = revised
Refer to page v for category descriptions.
Note: Long-term debt not adjusted for (i.e., includes) securitization bonds.
Source: S&P Global Market Intelligence and EEI Finance Department.

## PP&E In Service, Net 2018-2022

| Date | PP&E in Service, Net ($M) | % Change from 12/31/2018 |
|---|---|---|
| 12/31/2022 | 1,286,210 | 21.6% |
| 12/31/2021r | 1,221,089 | 15.4% |
| 12/31/2020 | 1,196,315 | 13.1% |
| 12/31/2019 | 1,129,880 | 6.8% |
| 12/31/2018 | 1,058,164 | |

Source: S&P Global Market Intelligence and EEI Finance Department.

## Cash Flow Statement

- Net Cash Provided by Operating Activities increased by $9.9 billion, or 12.0%. Cash provided by Depreciation and Amortization (D&A), a non-cash charge on the income statement, declined by $793 million, or 1.2%, at the consolidated industry level. However, D&A increased at 37 of the 44 utility holding companies that comprise EEI's data set; widespread increases are to be expected given the industry's aggressive clean energy infrastructure buildout. The decline at the consolidated level resulted from accounting at Exelon — the industry's fifth largest utility holding company at year-end 2021 in terms of net property, plant, and equipment in service — for the separation in 2022 of its regulated and competitive operations.

- Cash provided by Deferred Taxes & Investment Credits has leveled off over the last five years compared to much higher amounts previously. Deferred taxes had been at historically high levels due to elevated capex and use of bonus depreciation. The Tax Cuts & Jobs Act (TCJA), passed in late 2017, significantly reduced deferred taxes due to the reduction in the corporate income tax rate from 35% to 21% and the elimination of bonus depreciation.

- Change in Working Capital utilized $5.1 billion more cash in 2022 than in 2021. The difference traced mostly to accounting at one large utility holding company along with smaller contributions from just a few other large utilities. Conversely, Other Operating Changes in Cash used $17.3 billion less cash in 2022 than in 2021; in both years, this activity sourced to corporate actions at just a few large utilities. Neither of these two line items reflects broad-based fundamental industry trends.

- Net Cash Used in Investing Activities increased by $33.6 billion, or 29.0%. The industry's capital spending — by far the largest component of this metric — totaled $147.7 billion in 2022, up $13.7 billion, or 10.2%, from the 2021 total. Industry capex has reached a new record high in each of the past ten years. EEI member companies continue to invest in clean energy resources and the infrastructure necessary to make the power grid more modernized, more resilient, and more secure for all customers. Spending on transmission and distribution continues to increase relative to recent years, as EEI member companies expand their focus on adaptation, hardening, and resilience (AHR) initiatives. Investment in generation continues to be driven by the development of renewable energy and natural gas generation.

- Cash provided by Asset Sales decreased $11.9 billion, or 33.8%, from $35.3 billion in 2021 to $23.4 billion in 2022. The decrease resulted in part from PPL's June 2021 sale of its U.K. utility business, Western Power Distribution (WPD), to National Grid for $10.4 billion (nearly one-third of 2021's consolidated industry total). However, 2022 was not inactive; eight utility holding companies reported asset sales in 2022 in excess of $1 billion and 25 recorded proceeds from asset sales. Cash used for Asset Purchases increased by $2.1 billion, or 12.2%, to $19.7 billion; this was driven by actions at just a few utilities, including PPL's purchase in 2022 of Rhode Island utility Narragansett Electric.

- Net Cash Provided by Financing Activities rose by $20.6 billion, or 59.8%. The large increase resulted primarily from widespread debt issuance to fund aggressive clean energy infrastructure investment programs. Debt issuance is routine in the normal course of financing operations for such a capital-intensive industry. Nearly all of the 44 underlying utility holding companies contributed to the $67.3 billion net increase in the industry's consolidated long-term debt in 2022. The Net Change in Short-term Debt also added to the cash provided by financing activities, but at a relatively lower $8.2 billion amount, up $3.2 billion from the 2021 total. Common equity issuance and share repurchases were close to last year's level in absolute terms and remained below the totals in 2018, 2019 and 2020. No utilities issued preferred equity in 2022, compared to $3.8 billion in 2021. This was the first year without preferred equity issuance since 2010.

- Dividends Paid to Common Shareholders rose 3.7%, to $31.4 billion.

## Statement of Cash Flows

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

| $ Millions | 12 Months Ended | | |
|---|---|---|---|
| | 12/31/2022 | 12/31/2021r | % Change |
| Net Income | $43,570 | $42,277 | 3.1% |
| Depreciation and Amortization | 63,274 | 64,067 | (1.2%) |
| Deferred Taxes and Investment Credits | 2,659 | 5,278 | (49.6%) |
| Operating Changes in AFUDC | (1,599) | (1,453) | 10.1% |
| Change in Working Capital | (12,490) | (7,381) | 69.2% |
| Other Operating Changes in Cash | (3,093) | (20,388) | (84.8%) |
| **Net Cash Provided by Operating Activities** | **92,322** | **82,400** | **12.0%** |
| Capital Expenditures | (147,748) | (134,063) | 10.2% |
| Asset Sales | 23,393 | 35,340 | (33.8%) |
| Asset Purchases | (19,679) | (17,535) | 12.2% |
| Net Non-Operating Asset Sales and Purchases | 3,714 | 17,805 | (79.1%) |
| Change in Nuclear Decommissioning Trust | (698) | (314) | 122.2% |
| Investing Changes in AFUDC | 45 | 49 | (9.3%) |
| Other Investing Changes in Cash | (4,761) | 641 | NM |
| **Net Cash Used in Investing Activities** | **(149,448)** | **(115,881)** | **29.0%** |
| Net Change in Short-term Debt | 8,221 | 5,043 | 63.0% |
| Net Change in Long-term Debt | 67,265 | 45,444 | 48.0% |
| Proceeds from Issuance of Preferred Equity | – | 3,783 | NM |
| Preferred Share Repurchases | (1,158) | (2,100) | (44.9%) |
| Net Change in Prefered Issues | (1,158) | 1,683 | NM |
| Proceeds from Issuance of Common Equity | 10,957 | 9,432 | 16.2% |
| Common Share Repurchases | (2,036) | (1,531) | 33.0% |
| Net Change in Common Issues | 8,921 | 7,901 | 12.9% |
| Dividends Paid to Common Shareholders | (31,409) | (30,279) | 3.7% |
| Dividends Paid to Preferred Shareholders | (337) | (475) | (29.0%) |
| Other Dividends | – | – | NM |
| Dividends Paid to Shareholders | (31,746) | (30,754) | 3.2% |
| Other Financing Changes in Cash | 3,515 | 5,112 | (31.3%) |
| **Net Cash (Used in) Provided by Financing Activities** | **55,016** | **34,430** | **59.8%** |
| Other Changes in Cash | (38) | 12 | NM |
| Net increase (decrease) in cash and cash equivalents | $(2,148) | $961 | NM |
| Cash and cash equivalents at beginning of period | $15,526 | $16,369 | (5.2%) |
| Cash and cash equivalents at end of period | $13,378 | $17,330 | (22.8%) |

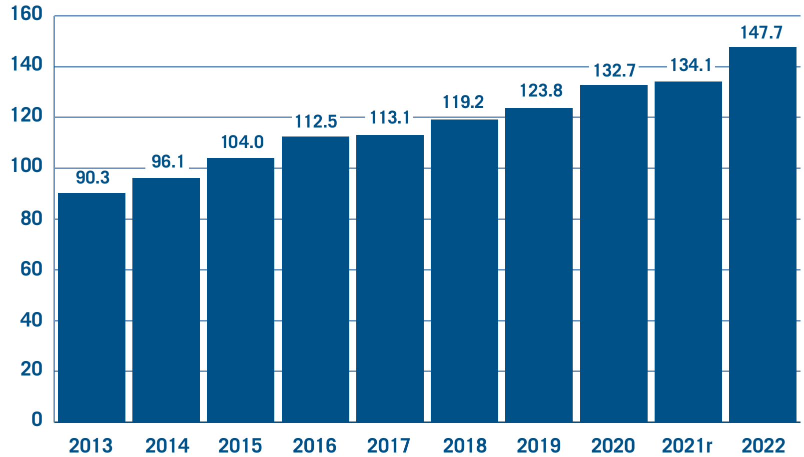
r = revised NM = not meaningful

Source: S&P Global Market Intelligence and EEI Finance Department.

## Capital Expenditures 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

($ Billions)



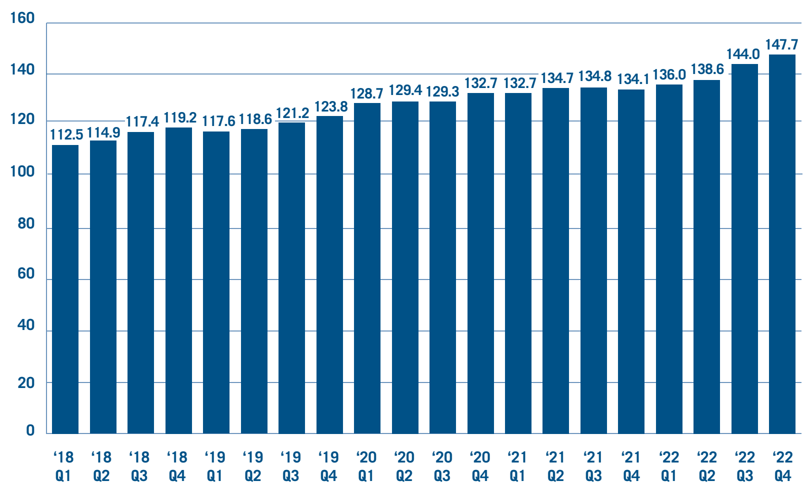

r = revised

Source: S&P Global Market Intelligence, company reports, and EEI Finance Department.

## Capital Expenditures—Trailing 12 Months

U.S. INVESTOR-OWNED ELECTRIC UTILITIES

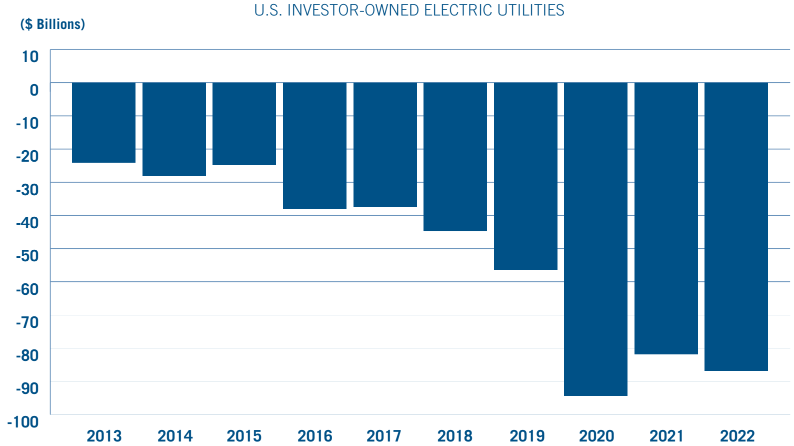
($ Billions)




Source: S&P Global Market Intelligence and EEI Finance Department.

## Free Cash Flow (FCF) 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




| ($ Billions) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| Net Cash Provided by Operating Activities | 87.1 | 89.0 | 101.6 | 98.3 | 101.2 | 100.1 | 95.3 | 67.7 | 82.4 | 92.3 |
| Capital Expenditures | (90.3) | (96.1) | (104.0) | (112.5) | (113.1) | (119.2) | (123.8) | (132.7) | (134.1) | (147.7) |
| Dividends Paid to Common Shareholders | (20.8) | (21.1) | (22.5) | (23.8) | (25.5) | (25.6) | (27.9) | (29.3) | (30.3) | (31.4) |
| **Free Cash Flow** | **(24.0)** | **(28.2)** | **(24.8)** | **(38.1)** | **(37.5)** | **(44.7)** | **(56.4)** | **(94.4)** | **(81.9)** | **(86.8)** |

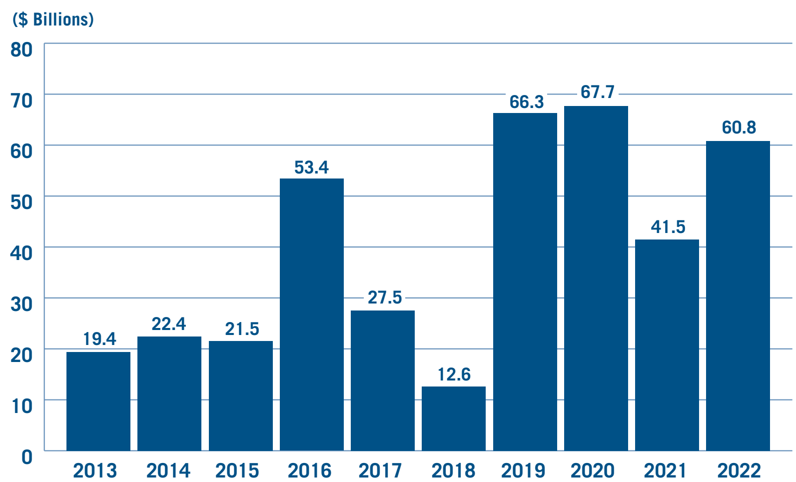
r = revised

Note: Totals may not equal sum of components due to rounding.

Source: S&P Global Market Intelligence and EEI Finance Department.

## Net Change in Long-term Debt 2013–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




r = revised

Note: Based on data from industry's consolidated balance sheet.

Source: S&P Global Market Intelligence and EEI Finance Department.

## Rate Review Summary

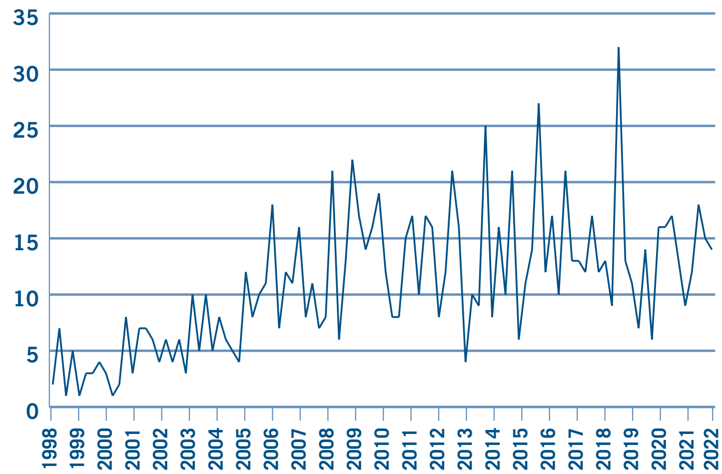
- There were 59 rate reviews filed, with 81 rate reviews decided. This is slightly more than the 55 rate reviews filed and less than the 82 rate reviews decided in 2021.
- Of the decided filings, electric companies requested revenue increases of approximately $6 billion in 2022; with approximately $4 billion approved.
- The average awarded ROE was 9.47 percent, a slight rebound from 2021 of 9.40 percent. For comparison, the average awarded ROE for 2020 was 9.43 percent, and for 2019 was 9.64 percent.
- Regulatory lag hovered around 8.01 months, which is an improvement from 8.41 months in 2021 and 8.93 months in 2020.

### Key Highlights from 2022

- **Alternative Regulation** – There are many flavors of alternative regulation, but multiyear rate plans (MYRPs) were a common request in 2022. Some of these requests were the result of legislation–the most recent being Washington, which requires electric companies to request approval of MYRPs of two to four years in length, while other proposals were made to temper rising costs. However, Commissions seem amenable to MYRPs and authorized their use in a handful of decisions throughout the country.

## Number of Rate Reviews Filed 1998–2022

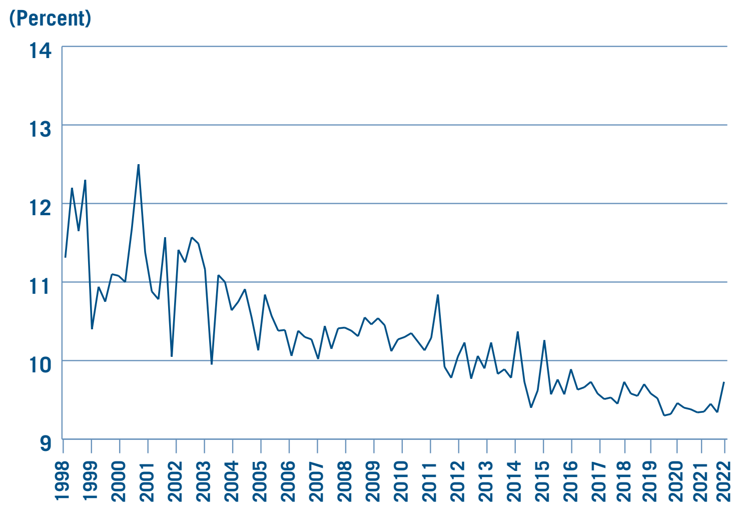
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

## Average Awarded ROE 1998-2022

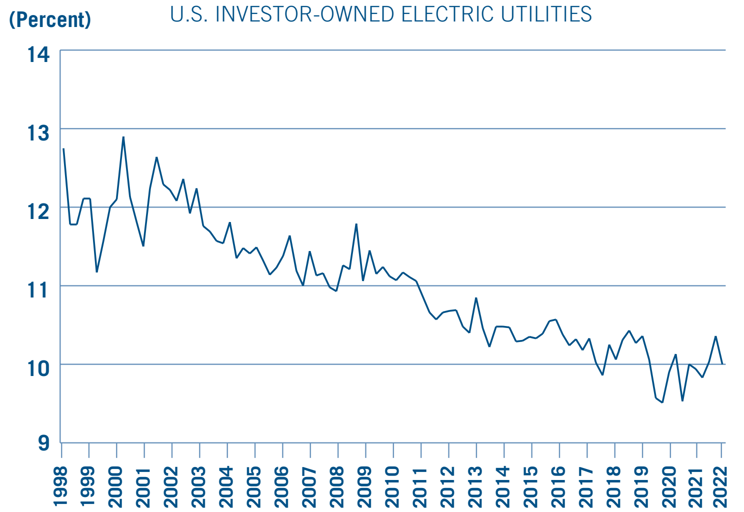
U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

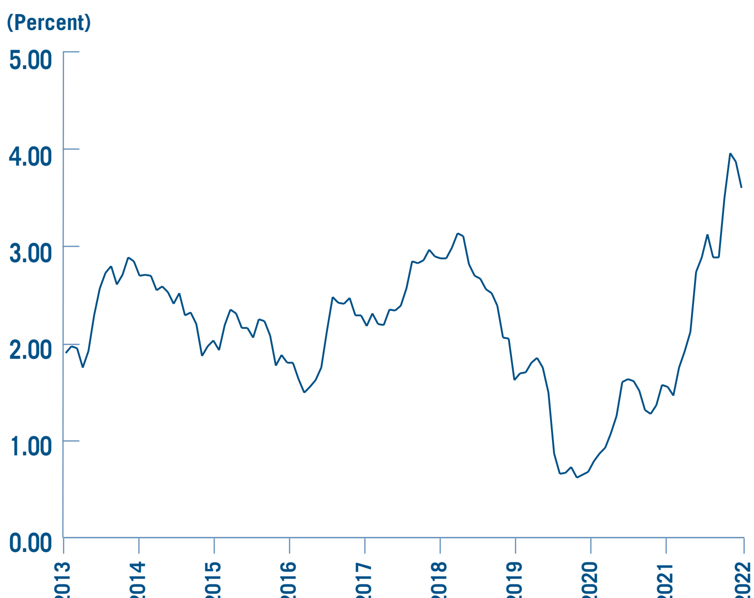
- **Affordability** – The topic of affordability continues to play a significant role in rate review activity. Usually the result of settlement discussions, electric companies have either increased funding for their low-income programs, including arrearage forgiveness, bill credits/discounts, or weatherization programs. Some have even proposed new pilot programs, such as Percentage of Income Payment Plans, to address the increased attention to this issue. Several electric companies are also looking at ways to improve upon current program design and implementation processes by engaging with community action agencies and other interested stakeholders, making enrollment easier, and expanding access to programs.
- **COVID-19 Cost Recovery** – The financial impacts of the pandemic are still being worked out in rate reviews. Many states issued orders allowing for deferral of COVID-related costs, for which electric companies are now seeking recovery. Most commonly, Commissions have authorized amortization of these costs over a two-to-five-year time frame. However, other companies have either been authorized to utilize test years that contain COVID-related costs or create a surcharge to recover costs from customers over a defined period of time. These costs are generally significant and in the millions of dollars, and we expect this issue will continue to come up as more electric companies file post-2020 rate reviews.

## Average Requested ROE 1998–2022




Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

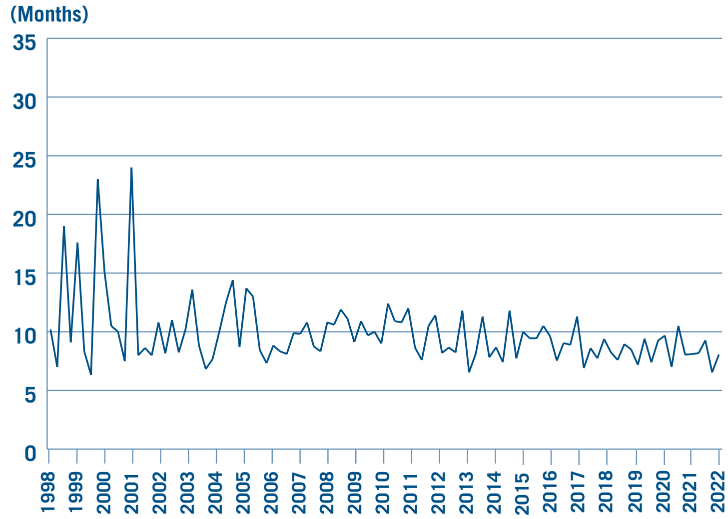
## 10-Year Treasury Yield
1/1/13 through 12/31/22




Source: U.S. Federal Reserve.

## Average Regulatory Lag 1998–2022

U.S. INVESTOR-OWNED ELECTRIC UTILITIES




Source: S&P Global Market Intelligence/Regulatory Research Assoc. and EEI Finance Department.

# Finance, Accounting, and Investor Relations

The Finance, Accounting, and Investor Relations teams are part of EEI's Business Operations Group. This division provides the leadership and management for advocating industry policies, technical research, and enhancing the capabilities of individual members through education and information sharing. The division's leadership is used in areas that affect the financial health of the investor-owned electric utility industry, such as finance, accounting, taxation, internal auditing, investor relations, risk management, and budgeting and financial forecasting. If you need research information about these issue areas, please contact an EEI Finance, Accounting, or Investor Relations staff member (listed in this section). Under the direction of both the Finance and the Accounting Executive Advisory Committees, the division provides staff representatives to work with issue area committees. These committees give member company personnel a forum for information exchange and training and an opportunity to comment on legislative and regulatory proposals.

## Publications

### Quarterly Financial Updates

A series of financial reports on the investor-owned segment of the electric utility industry. Quarterly Financial Update (QFU) reports include stock performance, dividends, credit ratings, and rate review summary.

### Financial Review

An annual report that provides a review of the financial performance of the investor-owned electric utility industry including the QFU topics mentioned above as well as the industry's consolidated financial statements. The report also includes an analysis in the areas of business segmentation, mergers & acquisitions, construction and fuel use by electric utilities.

### EEI Index

Quarterly stock performance of the U.S. investor-owned electric utilities. The EEI index, which measures total return and provides company rankings for year to date and trailing one-year periods, is widely used in company proxy statements and for overall industry benchmarking.

### Executive Accounting News Flash

Published quarterly and distributed to members of accounting committees, this update provides current information about the impact on our companies of evolving accounting and financial reporting issues. The News Flash is prepared jointly with AGA by the Utility Industry Accounting Fellow in coordination with our accounting staff in order to keep members informed on proposed and newly effective requirements from key accounting standard-setters.

### Introduction to Depreciation for Utilities and Other Industries

Updated in 2013, the latest edition of this book serves as a primer on the concepts of depreciation accounting including fundamental principles, life analysis techniques, salvage and cost of removal analysis methods and depreciation rate calculation formulas and examples.

## Conference Highlights

### Financial Conference

This three-day conference is the premier annual fall gathering of utilities and the financial community; it is attended by more than 1,000 senior executives, including utility CEOs, CFOs, treasurers, investor relations executives, and Wall Street investment analysts, portfolio managers, commercial and investment bankers and the rating agencies. The General Sessions cover topics of strategic interest to the industry and financial community. Contact Jacob Moshel for more information.

### Chief Financial Officers' Forum

This forum is held once a year in the fall in conjunction with the EEI Financial Conference. The forum provides an opportunity for chief financial officers to identify and discuss critical issues and challenges impacting the financial health of the electric utility industry. The forum is open to member company chief financial officers only. Contact Aaron Cope for more information.

### Finance Committee Meeting

This day and a half meeting is held in the spring or summer. The meeting covers current and emerging industry issues critical to the electric power industry. It also provides an opportunity for utility financial officers to identify best practices and share management skills that contribute to financial performance. Contact Aaron Cope for more information.

### Investor Relations Meeting

This one-day meeting is held in the spring. Executives gain insight on current and evolving industry issues, analysts' perspectives on the industry and have an opportunity to identify and share IR best practice concepts within and outside the electric utility industry. Contact Jacob Moshel for more information.

### Treasury Group Meeting

Half day meetings are held in the spring and the fall annually. Discussion is focused on pension funding, capital markets and economic and regulatory impacts on debt and equity issuances. Members are provided an opportunity to share and identify best practices beneficial to the well-being of the industry. Contact Jacob Moshel for more information.

### Accounting Leadership Conference

This annual meeting, held jointly with the Chief Audit Executives and their counterparts from AGA, covers current accounting, finance, business, and management issues for the Chief Accounting Officers and key accounting leadership of EEI member companies. Contact Randall Hartman for more information.

### Chief Audit Executives Conference

This annual conference provides a forum for EEI and AGA Chief Audit Executives to discuss issues and challenges and exchange ideas on utility-specific internal auditing topics. The conference is open to members of the Internal Auditing Committee and other employees of EEI/ AGA member companies designated by the CAE. Contact Dave Dougher for more information.

### Spring and Fall Accounting Conferences

Hosted by the EEI Corporate Accounting Committee, the Property Accounting & Valuation Committee, the Accounting Standards Committee, the Budgeting & Financial Forecasting Committee and the AGA Corporate Accounting and Property Accounting Committees, these conferences provide a forum for members to discuss current issues and challenges and exchange ideas in the electric and natural gas utility industries. The spring meeting is intended for all aforementioned committees, while the fall meeting is designed for the Corporate Accounting Committee and the Property Accounting & Valuation Committee. The meetings are open to members of the Committees and other employees of EEI/AGA member companies. Contact Dave Dougher for more information.

### Taxation Committee Meeting

This three-day meeting is held every June and November, providing an opportunity for member company tax personnel to discuss technical information on utility tax issues. In addition to information exchange, members are briefed on current developments concerning major tax issues through presentations by committee members, outside tax specialists, and EEI staff. Contact Mark Agnew for more information.

### Tax School

Hosted by the EEI Taxation Committee, this two- and half-day training is held every other year in the spring (The last two EEI Tax Schools were conducted as virtual meetings). The program is designed for tax managers and tax staff with two-plus years of tax experience or for financial accounting supervisors with tax responsibilities. The school is taught by a faculty of outstanding speakers from the accounting and legal professions as well as others from within the industry. Contact Mark Agnew for more information.

## Accounting Courses

### Introduction to Public Utility Accounting

This 4-day program, offered jointly with AGA, concentrates on the fundamentals of public utility accounting. It focuses on providing basic knowledge and a forum for understanding the elements of the utility business. It is intended primarily for recently hired electric and gas utility staff in the areas of accounting, auditing, and finance. Contact Randall Hartman or Dave Dougher for more information.

### Advanced Public Utility Accounting

This intensive, 4-day course, jointly sponsored with AGA, focuses on complex and specific advanced accounting and industry topics. It addresses current accounting issues including those related to deregulation and competition, as they affect EEI member companies. Contact Randall Hartman or Dave Dougher for more information.

### Property Accounting & Depreciation Training Seminar

The content from this seminar has been incorporated into the public utility accounting training courses described above and is no longer offered as a separate seminar. Contact Dave Dougher for more information.

### Utility Internal Auditor's Training

Provides utility staff auditors, managers, and directors with the fundamentals of public utility auditing and specific utility audit/accounting issues including advanced internal auditing topics and is presented jointly by EEI and AGA – convenes for two and one-half days. Contact Randall Hartman or Dave Dougher for more information.

### Additional Training Opportunities

Provides additional training opportunities as appropriate, such as Accounting for Energy Derivatives and FERC Accounting. Contact Randall Hartman or Dave Dougher for more information.

## The EEI Business Services and Finance Division Staff

**Richard McMahon**
Senior Vice President, Energy Supply & Finance, and Chief ESG Officer
(202) 508-5571
rmcmahon@eei.org

**Irene Ybadlit**
Senior Coordinator, Energy Supply and Finance
(202) 508-5502
iybadlit@eei.org

### Financial Analysis and Business Analytics

**Mark Agnew**
Senior Director, Financial Analysis
(202) 508-5049
magnew@eei.org

**Daniel Foy**
Director, Financial Analysis
(202) 508-5970
dfoy@eei.org

**Bill Pfister**
Managing Director, Business Analytics and Energy Supply
(202) 508-5531
bpfister@eei.org

**Steve Frauenheim**
Senior Manager, Business Analytics
(202) 508-5580
sfrauenheim@eei.org

### Accounting and Investor Relations

**Randall Hartman**
Senior Director, Accounting
(202) 508-5494
rhartman@eei.org

**Dave Dougher**
Senior Manager, Accounting
(202) 508-5570
ddougher@eei.org

**Aaron Cope**
Director, Investor Relations, Finance, & ESG
(202) 508-5127
acope@eei.org

**Jacob Moshel**
Senior Investor Relations Specialist
(202) 508-5057
jmoshel@eei.org

**Kim King**
Coordinator, Finance and Tax
(202) 508-5493
kking@eei.org

## Edison Electric Institute Schedule of Upcoming Meetings

To assist in planning your schedule, here are upcoming meetings related to finance and accounting that may be of interest. For further details, contact Aaron Cope at (202) 508-5127, Randall Hartman (202) 508-5494, or Dave Dougher (202) 508-5570.

**August 15-16, 2023**
**EEI/AGA Accounting Liaison Committee Meeting with FERC Staff**
FERC Office
Washington, DC

**August 28-30, 2023**
**EEI/AGA Utility Internal Auditor's Training Courses**
Loews Atlanta Hotel
Atlanta, Georgia

**August 28-31, 2023**
**EEI-AGA Introduction to Public Utility Accounting and Advanced Public Utility Accounting Training Courses**
Loews Atlanta Hotel
Atlanta, Georgia

**September 13-15, 2023**
**EEI/AGA Derivatives Training**
Hyatt Rosemont
Chicago, Illinois

**November 5-8, 2023**
**EEI/AGA Taxation Committee Meeting**
San Diego, California

**November 12-14, 2023**
**EEI Financial Conference**
JW Marriott Desert Ridge
Phoenix, Arizona

**November 12, 2023**
**EEI Treasury Group Meeting**
*(Closed meeting, admittance by invitation only)*
JW Marriott Desert Ridge
Phoenix, Arizona

**November 12, 2023**
**Chief Financial Officers Forum**
*(Closed meeting, admittance by invitation only)*
JW Marriott Desert Ridge
Phoenix, Arizona

**November 12-15, 2023**
**EEI/AGA Fall Accounting Conference**
The Scott Resort & Spa
Scottsdale, Arizona

**December (TBD), 2023**
**Investor Relations Planning Group Meeting**
*(Closed meeting, admittance by invitation only)*
New York, New York

**December (TBD), 2023**
**Wall Street Advisory Group Meeting**
*(Closed meeting, admittance by invitation only)*
New York, New York

**May 19-22, 2024**
**EEI/AGA Spring Accounting Conference**
Philadelphia, Pennsylvania

**June 23-26, 2024**
**EEI/AGA Accounting Leadership and Chief Audit Executives Conferences**
TBD

# U.S. Investor-Owned Electric Utilities

(At 12/31/2022)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
*Berkshire Hathaway Energy*
Black Hills Corporation
CenterPoint Energy, Inc.
*Cleco Corporate Holdings LLC*
CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Energy, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
Entergy Corporation
Evergy, Inc.
Eversource Energy
Exelon Corporation
FirstEnergy Corp.
Hawaiian Electric Industries, Inc.
IDACORP, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
NorthWestern Corporation
OGE Energy Corp.
Otter Tail Corporation
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Inc.
*Puget Energy, Inc.*
Sempra Energy
Southern Company
The AES Corporation *
*DPL Inc.*
*IPALCO Enterprises, Inc.*
Unitil Corporation
WEC Energy Group, Inc.
Xcel Energy Inc.

Note: This list includes 39 publicly traded U.S. electric utility holding companies plus an additional five electric utilities (shown in italics) that are not listed on U.S. stock exchanges because they are owned by holding companies not primarily engaged in the business of providing retail electric distribution services in the United States.

* The AES Corporation is not included in the count of 39, but rather its two U.S. electric utility subsidiaries are included in the group of five italicized companies.

## Other EEI Member Companies

Alaska Power & Telephone Company
American Transmission Company
Central Hudson Gas & Electric Corp.
Cross Texas Transmission
Duquesne Light Company
El Paso Electric
Florida Public Utilities
Green Mountain Power
ITC Holdings Corp.
Liberty Utilities
Mt. Carmel Public Utility Company
National Grid
Ohio Valley Electric Corporation
Sharyland Utilities
Tampa Electric an Emera Company
UGI Corporation
UNS Energy Corporation
Upper Peninsula Power Company
Vermont Electric Power Company

Note: These companies are not included in the EEI Financial Review data sets for one of the following reasons: they do not provide retail electric distribution service (i.e., transmission-only), they are subsidiaries of foreign-owned companies, they are not traded on a major U.S. stock exchange, or they are owned by a non-utility holding company and the granularity of publicly available financial data is insufficient.

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our U.S. members provide electricity for 220 million Americans and operate in all 50 states and the District of Columbia. EEI also has dozens of international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Safe, reliable, affordable, and increasingly clean energy enhances the lives of all Americans and powers the economy. As a whole, the electric power industry supports more than 7 million jobs in communities across the United States and contributes 5 percent to the nation's GDP.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at **www.eei.org**.

EEI
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
202-508-5000 | www.eei.org

**COMMENTS** — 9 Jun, 2023 | 04:50

# S&P Global Ratings Definitions

Sector Governments, Sovereign_s, U.S. Public Finance, Infrastructure & Utilities, Utilities & Power, Structured Finance

## Table of Contents

(**Editor's Note:** We republished this article on June 9, 2023, to delete a sentence on the ratings we assign to medium-term notes; add clarifying language, remove our Russia national scale, and replace "Turkey" with "Turkiye" in the "National And Regional Scale Ratings" section; and make minor updates.)

## S&P Global Ratings Disclaimers

The analyses, including ratings, of S&P Global Ratings and its affiliates (together, S&P Global Ratings) are statements of opinion as of the date they are expressed and not statements of fact or recommendations to purchase, hold, or sell any securities or make any investment decisions. S&P Global Ratings assumes no obligation

**14.** A CreditWatch listing, however, does not mean a rating change is inevitable, and when appropriate, a range of potential alternative ratings will be shown. CreditWatch is not intended to include all ratings under review. A CreditWatch carries one of the following designations to indicate the potential direction of a rating:

- Positive: a rating may be raised.
- Negative: a rating may be lowered.
- Developing: a rating may be raised, lowered, or affirmed.

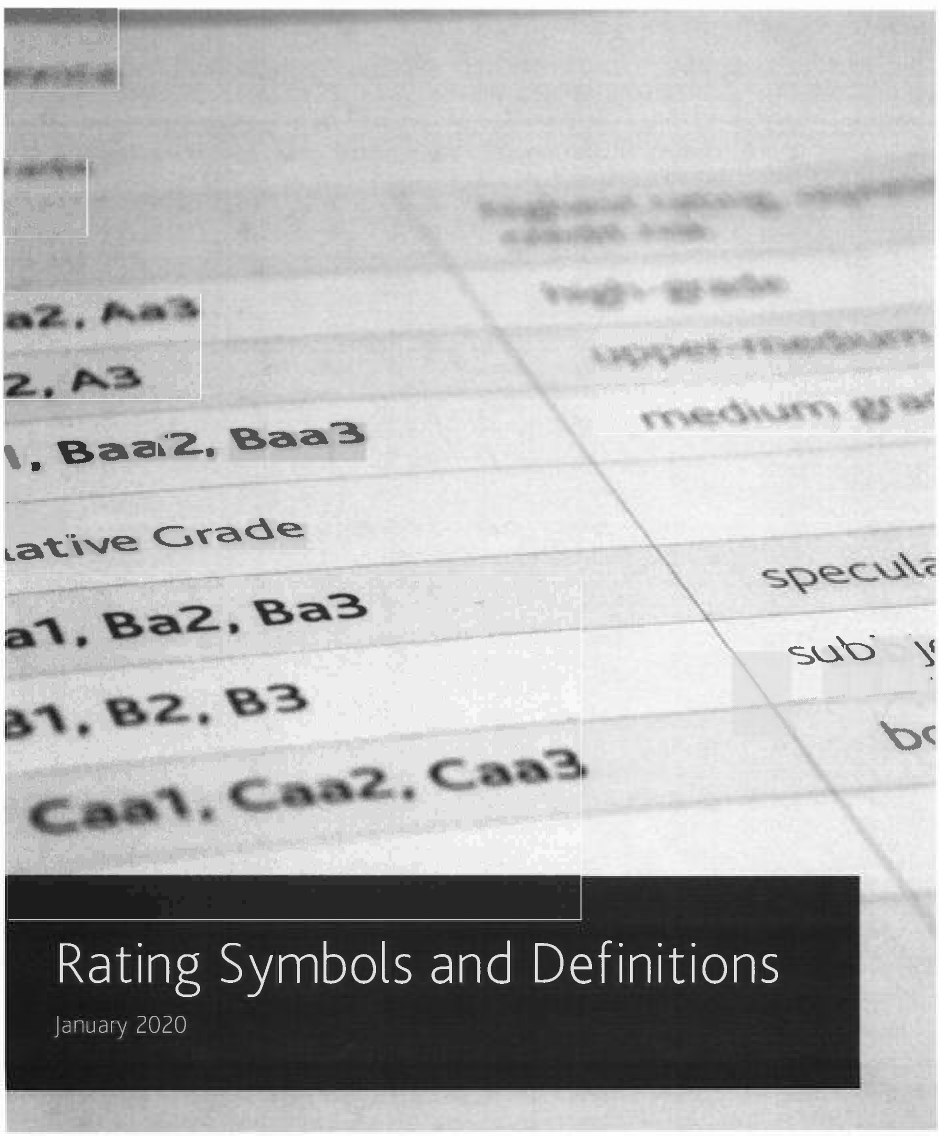
## B. Rating Outlooks

**15.** An S&P Global Ratings outlook assesses the potential direction of a long-term credit rating over the intermediate term, which is generally up to two years for investment grade and generally up to one year for speculative grade. In determining a rating outlook, consideration is given to any changes in economic and/or fundamental business conditions. An outlook can be one of the following:

- Positive: a rating may be raised.
- Negative: a rating may be lowered.
- Stable: a rating is not likely to change.
- Developing: a rating may be raised, lowered, or affirmed.

## C. Local Currency And Foreign Currency Ratings

**16.** S&P Global Ratings' issuer credit ratings make a distinction between foreign currency ratings and local currency ratings. A foreign currency rating on an issuer can differ from the local currency rating on it when the obligor has a different capacity to meet its obligations denominated in its local currency versus obligations denominated in a foreign currency.




# Rating Symbols and Definitions

January 2020

MOODY'S
INVESTORS SERVICE

### Timely Payment Indicator (TPI)

A TPI is Moody's assessment of the likelihood that timely payment would be made to covered bondholders following an Issuer Default. TPIs are assigned one of the following six assessment levels: Very High, High, Probable-High, Probable, Improbable, Very Improbable.

## Other Definitions

### Rating Outlooks

A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. Rating outlooks fall into four categories: Positive (POS), Negative (NEG), Stable (STA), and Developing (DEV). Outlooks may be assigned at the issuer level or at the rating level. Where there is an outlook at the issuer level and the issuer has multiple ratings with differing outlooks, an "(m)" modifier to indicate multiple will be displayed and Moody's press releases will describe and provide the rationale for these differences. A designation of RUR (Rating(s) Under Review) indicates that an issuer has one or more ratings under review, which overrides the outlook designation. A designation of RWR (Rating(s) Withdrawn) indicates that an issuer has no active ratings to which an outlook is applicable. Rating outlooks are not assigned to all rated entities. In some cases, this will be indicated by the display NOO (No Outlook).

A stable outlook indicates a low likelihood of a rating change over the medium term. A negative, positive or developing outlook indicates a higher likelihood of a rating change over the medium term. A rating committee that assigns an outlook of stable, negative, positive, or developing to an issuer's rating is also indicating its belief that the issuer's credit profile is consistent with the relevant rating level at that point in time.

The time between the assignment of a new rating outlook and a subsequent rating action has historically varied widely, depending upon the pace of new credit developments which materially affect the issuer's credit profile. On average, after the initial assignment of a positive or negative rating outlook, the next rating action – either a change in outlook, a rating review, or a change in rating – has followed within about a year, but outlooks have also remained in place for much shorter and much longer periods of time. Historically, approximately one-third of issuers have been downgraded (upgraded) within 18 months of the assignment of a negative (positive) rating outlook. After the initial assignment of a stable outlook, about 90% of ratings experience no change in rating during the following year.

### Rating Reviews

A review indicates that a rating is under consideration for a change in the near term.[15] A rating can be placed on review for upgrade (UPG), downgrade (DNG), or more rarely with direction uncertain (UNC). A review may end with a rating being upgraded, downgraded, or confirmed without a change to the rating. Ratings on review are said to be on Moody's "Watchlist" or "On Watch". Ratings are placed on review when a rating action may be warranted in the near term but further information or analysis is needed to reach a decision on the need for a rating change or the magnitude of the potential change.

The time between the origination of a rating review and its conclusion varies widely depending on the reason for the review and the amount of time needed to obtain and analyze the information relevant to make a rating determination. In some cases, the ability to conclude a review is dependent on whether a specific event occurs, such as the completion of a corporate merger or the execution of an amendment to a structured finance security. In these event-dependent cases and other unique situations, reviews can sometimes last 90 to 180 days or even longer. For the majority of reviews, however, where the conclusion of the review is not dependent on an event whose timing Moody's cannot control, reviews are typically concluded within 30 to 90 days.

Ratings on review for possible downgrade (upgrade) have historically concluded with a downgrade (upgrade) over half of the time.

15 Baseline Credit Assessments and Counterparty Risk Assessments may also be placed on review

FitchRatings

# Rating Definitions

assigned and often include an expectation of recovery, which may be notched above or below the issuer-level rating.

Issue ratings are assigned to secured and unsecured debt securities, loans, preferred stock and other instruments. Structured finance ratings are issue ratings to securities backed by receivables or other financial assets that consider the obligations' relative vulnerability to default.

Credit ratings are indications of the likelihood of repayment in accordance with the terms of the issuance. In limited cases, Fitch may include additional considerations (i.e. rate to a higher or lower standard than that implied in the obligation's documentation). Please see the section Specific Limitations Relating to Credit Rating Scales for details.

Fitch also publishes other ratings, scores and opinions. For example, Fitch provides specialized ratings of servicers of residential and commercial mortgages, asset managers and funds. In each case, users should refer to the definitions of each individual scale for guidance on the dimensions of risk covered in each assessment.

Fitch's credit rating scale for issuers and issues is expressed using the categories 'AAA' to 'BBB' (investment grade) and 'BB' to 'D' (speculative grade) with an additional +/– for 'AA' through 'CCC' levels, indicating relative differences of probability of default or recovery for issues. The terms "investment grade" and "speculative grade" are market conventions and do not imply any recommendation or endorsement of a specific security for investment purposes. Investment-grade categories indicate relatively low to moderate credit risk, while ratings in the speculative categories signal either a higher level of credit risk or that a default already occurred.

Fitch may also disclose issues relating to a rated issuer that are not and have not been rated. Such issues are also denoted as 'NR' on its webpage.

Credit ratings express risk in relative rank order, which is to say they are ordinal measures of credit risk and are not predictive of a specific frequency of default or loss. For information about the historical performance of ratings, please refer to Fitch's *Ratings Transition and Default Studies*, which detail the historical default rates. The European Securities and Markets Authority also maintains a central repository of historical default rates.

Fitch's credit ratings do not directly address any risk other than credit risk. Credit ratings do not deal with the risk of market value loss due to changes in interest rates, liquidity and/or other market considerations. However, market risk may be considered to the extent that it influences the ability of an issuer to pay or refinance a financial commitment. Nonetheless, ratings do not reflect market risk to the extent that they influence the size or other conditionality of the obligation to pay upon a commitment (for example, payments linked to performance of an equity index).

Fitch will use credit rating scales to provide ratings to privately issued obligations or certain note issuance programs, or for private ratings using the same public scale and criteria. Private ratings are not published, and are only provided to the issuer or its agents in the form of a rating letter.

The primary credit rating scales may also be used to provide ratings for a narrower scope, including interest strips and return of principal, or in other forms of opinions, such as Credit Opinions or Rating Assessment Services.

Credit Opinions are either a notch- or category-specific view using the primary rating scale and omit one or more characteristics of a full rating or meet them to a different standard. Credit Opinions will be indicated using a lowercase letter symbol combined with either an'*' (e.g. 'bbb+*') or (cat) suffix to denote the opinion status. Credit Opinions will be typically point-in-time but may be monitored if the analytical group believes information will be sufficiently available.

Rating Assessment Services are a notch-specific view using the primary rating scale of how an existing or potential rating may be changed by a given set of hypothetical circumstances. While Credit Opinions and Rating Assessment Services are point-in-time and are not monitored, they may have a directional Watch or Outlook assigned, which can signify the trajectory of the credit profile.

Ratings assigned by Fitch are opinions based on established, approved and published criteria. A variation to criteria may be applied but will be explicitly cited in our rating action commentaries (RACs), which are used to publish credit ratings when established and upon annual or periodic reviews.

Ratings are the collective work product of Fitch, and no individual, or group of individuals, is solely responsible for a rating. Ratings are not facts and, therefore, cannot be described as being "accurate" or "inaccurate." Users should refer to the definition of each individual rating for guidance on the dimensions of risk covered by the rating.

## Rating Outlooks and Rating Watches

Rating Outlooks and Watches are mutually exclusive.

Outlooks indicate the direction a rating is likely to move over a one- to two-year period. They reflect financial or other trends that have not yet reached or been sustained at the level that would cause a rating action, but which may do so if such trends continue. A Positive Rating Outlook indicates an upward trend on the rating scale. Conversely, a Negative Rating Outlook signals a negative trend on the rating scale. Positive or Negative Rating Outlooks do not imply that a rating change is inevitable, and similarly, ratings with Stable Outlooks can be raised or lowered without a prior revision to the Outlook. Occasionally, where the fundamental trend has strong, conflicting elements of both positive and negative, the Rating Outlook may be described as "Evolving."

Outlooks are currently applied on the long-term scale to certain issuer ratings (including sovereigns, corporates, financial institutions and insurance companies) and to both issuer ratings and obligations ratings in public finance in the U.S.; to issues in infrastructure and project finance; to IFS ratings; to issuer and/or issue ratings in a number of National Rating scales; and to the ratings of structured finance transactions and covered bonds. Outlooks are not applied to ratings assigned on the short-term scale. For financial institutions, Outlooks are not assigned to VRs, Government and Shareholder Support Ratings Derivative Counterparty Ratings and Ex-government Support Ratings.

Ratings in the 'CCC', 'CC' and 'C' categories typically do not carry Outlooks since the volatility of these ratings is very high and Outlooks would be of limited informational value. Defaulted ratings do not carry Outlooks.

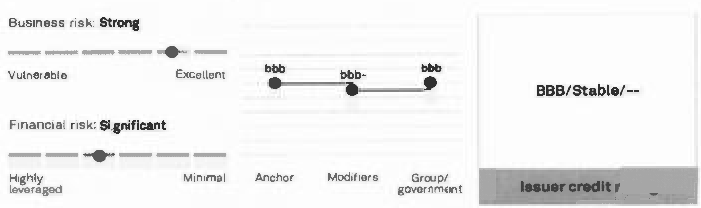
S&P Global
Ratings

RatingsDirect®

# Kentucky Power Co.

**September 14, 2023**

## Ratings Score Snapshot




Primary contact

**Daria Babitsch**
New York
917-574-4573
daria.babitsch
@spglobal.com

Research contributor

**PiyushSeth**
CRISIL Global Analytical Center, an S&P Global Ratings affiliate, Pune

## Credit Highlights

### Overview

| Key strengths | Key risks |
|---|---|
| Lower-risk, vertically integrated, regulated electric utility. | Limited geographic diversity and small customer base. |
| Credit-supportive and constructive regulatory framework in Kentucky. | Coal-fired generation increases environmental compliance exposure. |
| Balanced capital structure. | At the lower end of the range for its financial risk profile category. |

**We continue to monitor developments of Kentucky Power Co.'s (KPCo) base rate case that was filed in June 2023.** KPCo filed for an approximate $94 million increase based on a proposed 9.9% return on equity (ROE) and a 41.62% equity layer for capital structure. The rate request is driven by recent infrastructure investments, increased depreciation expense and higher interest expenses; we expect a rate outcome by January 2024. Separately, we will monitor the prudency determination of KPCo's $12 million of deferred purchased power costs not recoverable through its fuel adjustment clause.

**Alongside its base rate case, KPCo filed for securitization to recover the under-recovered costs associated with retiring the Big Sandy coal plant, storm costs, and purchase power costs.** In March 2023, Kentucky Senate Bill 192 became law, allowing for the securitization of certain generating plant retirements and extraordinary storm costs. In June, KPCo requested to securitize approximately $471 million of costs, including $289 million related to Big Sandy retirement and $79 million related to major storms from 2020-2023. We will continue to monitor the securitization filings.

**We assess KPCo at the lower end of its respective business risk and financial risk profile categories and incorporate this higher risk by assessing the comparable rating analysis (CRA) modifier as negative.** We believe KPCo's higher exposure to coal-fired generation, accounting for about 70% of its total generation, could lead to greater environmental compliance costs, increasing its business risk compared to peers. Additionally, we expect KPCo's funds from operations (FFO) to debt will be on the lower end of its financial risk profile category, reflecting FFO to debt of 11%-15%.

# Outlook

The stable outlook on KPCo reflects our expectations for timely recovery of approved capital expenditure (capex) and fuel costs, supporting the company's cash flow stability. Our base case for 2023-2025 assumes stand-alone FFO to debt of 11%-15%.

## Downside scenario

We could lower our ratings on KPCo in the next 24 months if:

- We downgrade parent AEP; or
- KPCo's financial performance weakens such that FFO to debt is below 11%.

## Upside scenario

We could upgrade KPCo if its stand-alone financial performance improves such that FFO to debt is greater than 15%, without an increase to business risk.

# Our Base-Case Scenario

### Assumptions

- EBITDA margin averaging about 25% through 2025;
- Effective management of regulatory risk and the continued recovery of prudent costs;
- Elevated capital spending of $160 million-$230 million per year for infrastructure investments; and
- All debt maturities refinanced.

## Key metrics

**Kentucky Power Co.--Forecast summary**

| Period ending | Dec-31-2022 | Dec-31-2023 | Dec-31-2024 | Dec-31-2025 |
|---|---|---|---|---|
| | 2022a | 2023e | 2024f | 2025f |
| **Adjusted ratios** | | | | |
| Debt/EBITDA (x) | 6.7 | 6.5-7 | 5-5.5 | 5-5.5 |
| FFO/debt (%) | 11.4 | 10-11 | 14-15 | 13-14 |
| FFO cash interest coverage (x) | 4.4 | 3-3.5 | 3.5-4 | 3.5-4 |

# Company Description

KPCo is a vertically integrated electric utility serving about 163,000 customers in eastern Kentucky. The company also sells wholesale electricity to various municipalities.

# Peer Comparison

**Kentucky Power Co.--Peer Comparisons**

| | Kentucky Power Co. | Kentucky Utilities Co. | Louisville Gas & Electric Co. |
|---|---|---|---|
| Foreign currency issuer credit rating | BBB/Stable/-- | A-/Stable/A-2 | A-/Stable/A-2 |
| Local currency issuer credit rating | BBB/Stable/-- | A-/Stable/A-2 | A-/Stable/A-2 |
| Period | Annual | Annual | Annual |
| Period ending | 2022-12-31 | 2022-12-31 | 2022-12-31 |
| Mil. | $ | $ | $ |
| Revenue | 773 | 2,074 | 1,798 |
| EBITDA | 192 | 923 | 732 |
| Funds from operations (FFO) | 146 | 732 | 591 |
| Interest | 48 | 122 | 96 |
| Cash interest paid | 43 | 113 | 84 |
| Operating cash flow (OCF) | 97 | 669 | 548 |
| Capital expenditure | 209 | 547 | 371 |
| Free operating cash flow (FOCF) | (112) | 122 | 177 |
| Discretionary cash flow (DCF) | (112) | (174) | (98) |
| Cash and short-term investments | 3 | 21 | 93 |
| Gross available cash | 3 | 21 | 93 |
| Debt | 1,286 | 3,112 | 2,471 |
| Equity | 920 | 4,038 | 3,166 |
| EBITDA margin(%) | 24.8 | 44.5 | 40.7 |
| Return on capital (%) | 2.6 | 7.3 | 7.6 |
| EBITDA interest coverage (x) | 4.0 | 7.6 | 7.7 |

**Kentucky Power Co.--Peer Comparisons**

| | | | |
|---|---|---|---|
| FFO cash interest coverage (x) | 4.4 | 7.5 | 8.1 |
| Debt/EBITDA (x) | 6.7 | 3.4 | 3.4 |
| FFO/debt (%) | 11.4 | 23.5 | 23.9 |
| OCF/debt (%) | 7.5 | 21.5 | 22.2 |
| FOCF/debt (%) | (8.7) | 3.9 | 7.2 |
| DCF/debt (%) | (8.7) | (5.6) | (3.9) |

## Business Risk

Our assessment of KPCo's business risk profile reflects its lower-risk, vertically integrated electric utility business, which operates under a generally constructive regulatory framework. The company has a small customer base of only about 163,000 and limited geographic diversity because it operates almost entirely in Kentucky. KPCo's service territory demonstrates modest growth. The company derives half of its energy sales from industrial customers, which leads to somewhat less stable operating cash flow. Additionally, coal makes up about 70% of the company's owned generation, which increases its environmental compliance exposure.

Under the regulatory jurisdiction of Kentucky, the company benefits from a fuel-cost adjustment mechanism that provides for incremental cost recovery when fuel costs rise. Moreover, KPCo's low-cost generation and efficient operations contribute to its competitive overall rates for its customers. The company has also received timely recovery of its approved capital spending.

## Financial Risk

KPCo benefits from various rate mechanisms that allow for the timely recovery of its costs and support more stable operating cash flows. We expect the company will continue to fund its investments in a manner that preserves its existing credit quality.

Under our base-case scenario, we anticipate stand-alone S&P Global Ratings-adjusted FFO to debt of 10%-11% in 2023. We expect the company's FFO to debt to improve to 13%-15% thereafter as it benefits from supportive recovery mechanisms, like the environmental cost rider, as well as formula transmission rates and forward test periods for rate cases. We forecast KPCo will increase its debt to EBITDA to high-6x in 2023, though we anticipate it will fall to low-6x to mid-5x thereafter. In addition, we estimate it will have negative discretionary cash flow through our forecast, which we expect it will fund, at least partly, with debt.

We assess KPCo's financial risk profile using our medial volatility financial benchmarks, which reflect its lower-risk regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed than those we use for typical corporate issuers.

### Debt maturities

- Through 2023: $275 million;
- 2024: $215 million;
- 2025:--;
- 2026: $265 million;
- 2027: $40 million; and

- Thereafter: $450 million.

### Kentucky Power Co.--Financial Summary

| Period ending | Dec-31-2017 | Dec-31-2018 | Dec-31-2019 | Dec-31-2020 | Dec-31-2021 | Dec-31-2022 |
|---|---|---|---|---|---|---|
| Reporting period | 2017a | 2018a | 2019a | 2020a | 2021a | 2022a |
| Display currency (mil.) | $ | $ | $ | $ | $ | $ |
| Revenues | 643 | 642 | 619 | 550 | 646 | 773 |
| EBITDA | 185 | 203 | 189 | 176 | 171 | 192 |
| Funds from operations (FFO) | 143 | 166 | 148 | 148 | 137 | 146 |
| Interest expense | 49 | 42 | 44 | 41 | 38 | 48 |
| Cash interest paid | 45 | 40 | 41 | 40 | 39 | 43 |
| Operating cash flow (OCF) | 124 | 118 | 81 | 78 | 70 | 97 |
| Capital expenditure | 95 | 135 | 160 | 153 | 164 | 209 |
| Free operating cash flow (FOCF) | 30 | (17) | (80) | (75) | (94) | (112) |
| Discretionary cash flow (DCF) | (5) | (17) | (85) | (75) | (94) | (112) |
| Cash and short-term investments | 1 | 1 | 1 | 2 | 1 | 3 |
| Gross available cash | 1 | 1 | 1 | 2 | 1 | 3 |
| Debt | 927 | 938 | 1,028 | 1,092 | 1,178 | 1,286 |
| Common equity | 670 | 733 | 782 | 823 | 874 | 920 |
| **Adjusted ratios** | | | | | | |
| EBITDA margin (%) | 28.8 | 31.6 | 30.6 | 31.9 | 26.5 | 24.8 |
| Return on capital (%) | 6.1 | 6.5 | 5.2 | 3.9 | 2.8 | 2.6 |
| EBITDA interest coverage (x) | 3.8 | 4.8 | 4.4 | 4.2 | 4.5 | 4.0 |
| FFO cash interest coverage (x) | 4.2 | 5.1 | 4.6 | 4.7 | 4.5 | 4.4 |
| Debt/EBITDA (x) | 5.0 | 4.6 | 5.4 | 6.2 | 6.9 | 6.7 |
| FFO/debt (%) | 15.5 | 17.7 | 14.4 | 13.5 | 11.6 | 11.4 |
| OCF/debt (%) | 13.4 | 12.6 | 7.8 | 7.1 | 6.0 | 7.5 |
| FOCF/debt (%) | 3.2 | (1.8) | (7.7) | (6.8) | (7.9) | (8.7) |
| DCF/debt (%) | (0.5) | (1.8) | (8.2) | (6.8) | (7.9) | (8.7) |

### Reconciliation Of Kentucky Power Co. Reported Amounts With S&P Global Adjusted Amounts (Mil.$)

| | | Debt | Shareholder Equity | Revenue | EBITDA | Operating Income | Interest expense | S&PGR adjusted EBITDA | Operating cash flow | Dividends | Capital expenditure |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Financial year | Dec-31-2022 | | | | | | | | | | |
| Company reported amounts | | 1,273 | 920 | 773 | 177 | 54 | 45 | 192 | 85 | - | 210 |

**Reconciliation Of Kentucky Power Co. Reported Amounts With S&P Global Adjusted Amounts (Mil.$)**

| | Debt | Shareholder Equity | Revenue | EBITDA | Operating income | Interest expense | S&PGR adjusted EBITDA | Operating cash flow | Dividends | Capital expenditure |
|---|---|---|---|---|---|---|---|---|---|---|
| Cash taxes paid | - | - | - | - | - | - | (2) | - | - | - |
| Cash interest paid | - | - | - | - | - | - | (42) | - | - | - |
| Lease liabilities | 1 | - | - | - | - | - | - | - | - | - |
| Operating leases | - | - | - | 14 | 0 | 0 | (0) | 14 | - | - |
| Accessible cash and liquid investments | (3) | - | - | - | - | - | - | - | - | - |
| Capitalized interest | - | - | - | - | - | 2 | (2) | (2) | - | (2) |
| Asset-retirement obligations | 15 | - | - | 1 | 1 | 1 | - | - | - | - |
| Nonoperating income (expense) | - | - | - | - | 1 | - | - | - | - | - |
| Total adjustments | 13 | - | - | 15 | 2 | 3 | (46) | 12 | - | (2) |
| **S&PGlobal Ratings adjusted** | **Debt** | **Equity** | **Revenue** | **EBITDA** | **EBIT** | **Interest expense** | **Funds from Operations** | **Operating cash flow** | **Dividends** | **Capital expenditure** |
| | 1,286 | 920 | 773 | 192 | 56 | 48 | 146 | 97 | - | 209 |

# Liquidity

As of March 31, 2023, we assess KPCo's liquidity as adequate. This reflects our expectation that its sources of cash will be 1.1x its uses over the next 12 months and our belief its net sources will remain positive even if its consolidated EBITDA declines 10%. We believe the company's predictable framework provides it with cash flow stability in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity.

In addition, we believe KPCo can absorb high-impact, low-probability events, which reflects its reliance on the AEP utility money pool, and our expectation that KPCo could reduce its high capital spending (about $160 million-$230 million per year) during stressful periods if needed. Furthermore, our assessment reflects the company's generally prudent risk management, sound relationships with its banking group and its satisfactory standing in the credit markets (its credit default swap spreads are in line with those of its investment-grade utility peers).

Overall, we anticipate KPCo can withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations. The company's next big long-term debt maturity is in December 2023, when about $275 million comes due, which we expect it will proactively address well in advance of the due date.

| Principal liquidity sources | Principal liquidity uses |
|---|---|
| • Cash and liquid investments of about $2 million as of March 31, 2023;<br>• Estimated cash FFO of about $130 million; and<br>• Expected ongoing group support of $500 million. | • Debt maturities, including affiliate advances, of about $490 million; and<br>• Maintenance capital spending of roughly $65 million. |

## Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of KPCo given its high level of coal-based power generation. Specifically, the company derives the majority (~70%) of its 1,075 megawatts of owned generation capacity from coal, with the remainder generated from natural gas. KPCo's reliance on coal-fired generation exposes it to heightened risks, including the ongoing cost of operating older units in the face of disruptive technology advances and the potential for significant required capital investments to meet increasing environmental regulation.

## Group Influence

We base our rating on KPCo on the consolidated group credit profile of its parent, AEP, and the application of our group rating methodology. We deem the company to be a moderately strategic subsidiary of AEP, which reflects our view that it would likely receive extraordinary support from AEP--particularly during periods of severe stress--and is reasonably successful. We rate KPCo 'BBB', which is one notch higher than our 'bbb-' stand-alone credit profile.

## Issue Ratings--Subordination Risk Analysis

### Capital structure

As of June 30, 2023, KPCo's capital structure comprises about $1.25 billion of debt.

### Analytical conclusions

We rate KPCo's senior unsecured debt at the same level as our issuer credit rating because it is the debt of a qualifying investment-grade utility.

### Rating Component Scores

| | |
|---|---|
| **Foreign currency issuer credit rating** | BBB/Stable/-- |
| **Local currency issuer credit rating** | BBB/Stable/-- |
| **Business risk** | Strong |
| Country risk | Very Low |
| Industry risk | Very Low |
| Competitive position | Satisfactory |
| **Financial risk** | Significant |
| Cash flow/leverage | Significant |
| **Anchor** | bbb |
| Diversification/portfolio effect | Neutral (no impact) |
| Capital structure | Neutral (no impact) |
| Financial policy | Neutral (no impact) |
| Liquidity | Adequate (no impact) |
| Management and governance | Satisfactory (no impact) |
| Comparable rating analysis | Negative (-1notch) |
| **Stand-alone credit profile** | bbb- |

## Related Criteria

- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

## Ratings Detail (as of September 14, 2023)*

| | |
|---|---|
| **Kentucky Power Co.** | |
| ssuer Credit Rating | BBB/Stable/-- |
| **Issuer Credit Ratings History** | |
| 20-Apr-2023 | BBB/Stable/-- |
| 28-Oct-2021 | BBB+/Watch Neg/-- |
| 28-Apr-2021 | BBB+/Watch Dev/-- |
| **Related Entities** | |
| **AEP Generating Co.** | |
| ssuer Credit Rating | A-/Stable/-- |
| **AEP Texas Inc.** | |
| ssuer Credit Rating | A-/Stable/-- |
| Senior Unsecured | A- |
| **AEP Transmission Co. LLC** | |
| ssuer Credit Rating | A-/Stable/-- |
| Senior Unsecured | A- |
| **American Electric Power Co. Inc.** | |
| ssuer Credit Rating | A-/Stable/A-2 |
| Commercial Paper | |
| *Local Currency* | A-2 |
| Junior Subordinated | BBB |
| Junior Subordinated | BBB+ |
| Senior Unsecured | BBB+ |
| **Appalachian Power Co.** | |
| ssuer Credit Rating | A-/Stable/A-2 |
| Senior Unsecured | A- |
| **Indiana Michigan Power Co.** | |
| ssuer Credit Rating | A-/Stable/A-2 |
| **Ohio Power Co.** | |
| ssuer Credit Rating | A-/Stable/-- |
| Senior Unsecured | A- |
| **Public Service Co. of Oklahoma** | |
| ssuer Credit Rating | A-/Stable/-- |
| Senior Unsecured | A- |
| **RGS (AEGCO) Funding Corp.** | |
| ssuer Credit Rating | A-/Stable/-- |
| **RGS (I&M) Funding Corp.** | |
| ssuer Credit Rating | A-/Stable/-- |

## Ratings Detail (as of September 14, 2023)*

**Southwestern Electric Power Co.**

| | |
|---|---|
| ssuer Credit Rating | A-/Stable/-- |
| Senior Unsecured | A- |

**Wheeling Power Co.**

| | |
|---|---|
| ssuer Credit Rating | A-/Stable/-- |

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

28-Oct-2021 | 17:16 EDT

# Kentucky Power Co. CreditWatch Implications Revised To Negative From Developing On AEP Sale Agreement

- American Electric Power Co. Inc. (AEP) announced that it has reached an agreement to sell Kentucky Power Co. (KPCo) and a Kentucky transmission entity to Algonquin Power & Utilities Corp. (APUC) for about $2.85 billion, including assumed debt of about $1.2 billion. The transaction is expected to close by the end of the second quarter of 2022.
- We revised the CreditWatch implications on KPCo to negative from developing on our 'BBB+' issuer credit rating and issue-level ratings on its senior unsecured debt. We previously placed the ratings on CreditWatch with developing implications on April 28, 2021.
- The revised CreditWatch placement reflects the announced sale of KPCo to lower-rated APUC, which is below our issuer credit rating on KPCo.

NEW YORK (S&P Global Ratings) Oct. 28, 2021--S&P Global Ratings today took the rating actions listed above.

We revised the CreditWatch implications on KPCo to negative from developing.

The CreditWatch with negative implications reflects our expectation that we will likely downgrade KPCo by one notch as APUC, the acquiring entity, is currently rated 'BBB', and we expect to align our ratings on KPCo with those on APUC.

Our assessment of KPCo's stand-alone credit profile (SACP) remains 'bbb'.

We continue to assess the company's business risk as strong and its financial risk as significant. Our business risk assessment reflects the regulatory support KPCo receives in Kentucky. The company was under a three-year base rate stay-out through 2020. The recent increase in KPCo's revenue supports its credit quality because it will enable it to recover a higher level of its capital and operating expenses. The company has a small customer base of about 170,000 and limited geographic diversity given that it operates almost entirely in Kentucky. That said, KPCo's service territory demonstrates modest growth. The company derives about half of its energy sales from industrial customers, which leads to less stability in its operating cash flow than if its customer base was entirely residential. KPCo continues to be exposed to energy transition risks because of its coal-fired generation, which accounts for most of its generation capacity.

We assess the company's financial risk profile as significant, which reflects its financial measures, including our expectation for funds from operations (FFO) to debt of 16%-17% through 2023.

Our assessment of KPCo's financial risk profile incorporates its recently approved rate case, which will strengthen its financial risk. We use our medial volatility table benchmarks to assess KPCo's financial risk, which are more relaxed benchmarks than those we use for typical corporate issuers. This reflects the company's steady cash flows, low-risk rate-regulated utility operations, and effective management of regulatory risk.

Our assessment of KPCo's group status as moderately strategic lifts our issuer credit rating on the company by one notch above its SACP to account for its limited group support.

The CreditWatch placement reflects AEP's announced sale of KPCo to lower-rated APUC. We expect to remove the CreditWatch and lower the ratings on KPCo to align with the lower-rated parent as the acquiring company nears or completes the transaction.

## Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- Criteria|Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors ForThe Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

LESSER

# CHAPTER 3
# THE ROLE OF THE REVENUE REQUIREMENT

## 3.1 Introduction

No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit, while fending off competitors. Regulated firms are no exception. They face the same constraints, with the exception that, typically, their competitors are limited either by economics or by statute.[1]

A basic concept underlying all forms of economic regulation is that a regulated firm must have the *opportunity* to recover its costs. Privately held firms must be able to obtain a "reasonable" return on *prudent* investments, two loaded words that have been, and continue to be, key areas of regulatory disputes. Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate. And if an investment is not prudent, it is not likely to be made.

Regulatory regimes in all countries and all political jurisdictions, at least those that wish to have well-functioning electric and natural gas industries, rely on this cost recovery plus investment return concept, which underlies all of the different forms of rate regulation we will encounter. Depending on the jurisdiction, the concept is called variously: *allowed revenues, value added of the regulated activity* (such as distribution or transport), *permissible revenues, rate base, regulated revenues, tariff base,* or *total revenue*. We use the term *revenue requirement*.[2]

Two primary components make up the revenue requirement: *operating costs* and *capital costs*. Operating costs include such diverse categories as administrative and general costs (rent, employee salaries, etc.), fuel costs (e.g., for generating electricity and operating natural gas

---

1 Even for a pure monopolist, at some price there will always be a "competitive" alternative.

2 The literature in regulatory economics has referred to the same concept widely. *See, e.g.*, Charles F. Phillips, *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1993), 176.

LESSER



## Prudence and Prudent Management

Under *Good Utility Practice*, a regulated firm's operating and investment decisions are typically considered prudent unless proven otherwise.[6] In other words, utility management is given the benefit of the doubt, and management's decisions are presumed reasonable unless the facts show otherwise. For example, the regulator would need to establish that providing luxurious cars and lavish offices to the regulated firm's executives was not a necessary part of providing electric service. Moreover, the prudence of managerial decisions must be judged on their reasonableness at the time those decisions were made and based on information then available. Prudence is not meant as an exercise in hindsight regulation. In essence, a prudent decision is one that a reasonable person could have made in good faith, given the information and decision tools available at the time of the decision.

In the early 1960s, several economists identified the possibility that regulated utilities would engage in imprudent behavior by *gold-plating* investments.[7] Gold-plating occurs when a utility spends excessively on equipment to provide services that could be provided more efficiently or that are not necessary. Gold-plating leads to artificial increases in regulated rates.[8]

## Used and Useful

A second regulatory principle states that an asset should be "used and useful" in order to be included in the rate base for calculating regulated tariffs. The only criterion that is tested as "used and useful" is whether the assets are used in providing services and are useful to the ratepayers. For example, suppose a nuclear plant investment was prudent at the time construction began, but that construction was never completed because of cost overruns. As a result, the unfinished plant would not be used and useful, since it would not be generating any electricity.

---

6 For example, U.S. Supreme Court Justice Brandeis referred to the prudence of investments as follows: "Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown," *Missouri ex rel. Southwestern Bell Tel. Co. v. Mo. PSC*, 262 U.S. 276 (1923).

7 *See* Harvey Averch and Leland Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review*, December 1962, 1052–1069. *See also*, Stanislaw Wellisz, "Regulation of Natural Gas Pipeline Companies: An Economic Analysis," *Journal of Political Economy*, February 1963, 30–43. These authors argued that utilities had an incentive to increase capital costs so as to maximize the return on their investments.

8 Although less common, even expenditures to improve safety can be considered gold-plating if the safety levels exceed minimum requirements established by the government.

LESSER



In the 1980s, the used and useful principle was expanded by some regulators, and controversially so, to include an economic component. For example, Phillips notes a 1986 case before the Massachusetts Department of Public Utilities.[9] In that case, the regulator found that the electric utility's investment in new generating capacity would be used and useful only if the net cost of that capacity was less than alternative investments. As we discuss in Chapter 5, the problem with an economic used and useful principle is that it replaces a reasoned judgment standard, as defined under *Good Utility Practice*.[10]

## Known and Measurable

To be included in a regulated firm's revenue requirement, costs must be ***known and measurable***. That is, the regulated firm must justify with documentation, facts, and methodology those costs it wishes ratepayers to reimburse. Typically, a regulated firm is required to prove that all of the costs it is requesting to recover are legitimate expenditures. For example, the firm should be able to describe the details of the duties and obligations for the services provided by its employees. Essentially, all of the costs the regulated firm wishes to recover from captive ratepayers must be realistic. Moreover, the firm should provide enough information to show that those costs are a necessary part of its operations.

## The Regulatory Compact and the "Just and Reasonable" Principle

There is also a long-standing, but unwritten, rule that governs cost recovery and lies at the heart of establishing *regulated* prices. This rule is known as the *regulatory compact*. Under the regulatory compact, the regulator grants the company a protected monopoly, essentially a franchise, for the sale and distribution of electricity or natural gas to customers in its defined service territory. In return, the company commits to supply the full quantities demanded by those customers at a price calculated to cover all operating costs plus a "reasonable" return on the capital invested in the enterprise.[11] The first half of this "compact" protects the company from would-be competitors and secures for the public the substantial

[9] *Re Western Mass. Elec. Co.*, 80 PUR4th 479, at 520 (Mass. D.P.U. 1986).

[10] For a much more detailed discussion, see Jonathan Lesser, "The Economic Used and Useful Test: Implications for a Restructured Electric Industry," *Energy Law Journal* 23, no. 2 (2002): 349–81.

[11] In other cases where rates are regulated, such as a wholesale generator that is not allowed to sell power at market rates because of market power concerns or an interstate natural gas pipeline owner that is considered a bottleneck facility, there is no regulatory compact per se, since there is no obligation to serve.

economies of scale available in the large-scale production of electricity.[12] The second half of the "compact" counteracts the injurious tendency of monopolists to raise prices above the level that would prevail in a competitive market.

Because the regulatory compact is nowhere written down, you may get different answers as to whether it, in fact, exists, depending on whom you ask. Not so with the *just and reasonable* standard, which can trace its origins to the *just price* doctrine of medieval times and to the Takings Clause of the Fifth Amendment of the U.S. Constitution.[13] Where the just and reasonable standard comes into play arises from the concerns raised by Alfred Kahn. The regulatory compact is a tacit agreement between regulators and the regulated, but it does not give regulated firms *carte blanche* to recover any and all costs. Regulated firms are not guaranteed recovery of the costs associated with lavish offices, "gold-plated" plants, and multimillion-dollar salaries for all.[14] The costs must be just and reasonable.[15]

Together, the regulatory compact and the just and reasonable standard provide the crucial foundation for rate regulation. Both underlie the estimation of a regulated firm's costs, the allocation of those costs among different customers, the allowed return on the firm's capital investments, and the prices that regulators set for different classes of customers. Moreover, as we discuss in Chapter 9, the just and reasonable standard also underlies assessments of a firm's market power and the reasonableness of allowing a firm to compete unfettered in different markets.

## 3.4 Why Revenue Requirements Underlie All Regulatory Structures

At the beginning of this chapter, we noted that the revenue requirement underlies all regulatory structures, even if the methodologies used to calculate revenue requirements and the regulatory regimes within which firms operate differ substantially. Despite their differences,

---

12 The company is not necessarily protected against unregulated competitors. For example, if you decide your natural ga furnace is too expensive to operate, you can always install an oil-fired one and tell the natural gas company you no longe want its services.

13 *See, e.g.*, Charles F. Phillips, *The Regulation of Public Utilities*, 3d ed. (Arlington, VA: Public Utilities Reports, 199 89–93.

14 A detailed discussion of the "A-J-W" effect can be found in Alfred Kahn, *The Economics of Regulation: Principl Institutions*, vol. II (New York: Wiley, 1970), 49–59. The actual extent of the A-J-W effect has been debated for ma years.

15 The *just and reasonable* standard has also been adopted in other countries. For example, many Latin American coun that privatized their electric and natural gas industries included a *just and reasonable* standard in the initial privatizati legislation. *See, e.g.*, Article 40 of Law Nº 24,065, "The Electricity Law," (January 16, 1992), Argentina.

PHILLIPS



also require fair value, no generalization at all can be made concerning the findings of the regulatory authorities.[88]

## *Used and Useful, Prudent Investment and Excess Capacity*

Several valuation issues are of particular significance to the electric utility industry. Under traditional rate-making principles, public utilities are entitled to recover "prudent" investments when they become "used and useful." Certain items may be excluded from the rate base, including "excess capacity." But since the late 1970s, it has become clear that all three terms lack precise definitions.

**Used and Useful.** For decades, used and useful referred to needed capacity —that is, a determination as to whether a plant was actually used in service and was useful in providing service. If not, or if any expenditures were imprudent, all or part of the investment in a plant would be excluded from rate base. Today, however, used and useful has been held by some commissions to be a broader concept. The Massachusetts commission, to cite one example, holds that under the used and useful standard, it must "determine whether a utility investment is needed *and economically desirable.*"[89] Explains the commission:

> Need for a new electric utility production plant is established if it can be shown that the investment in question can provide either capacity which is required by the utility or energy, at a net cost which is lower than the cost of the capacity which it displaces. Once need for capacity or reliability, as the case may be, and/or energy savings has been established, the [commission] then must determine the extent to which an investment is useful and thus the extent to which a return should be allowed on the investment.[90]

Thus, a threshold issue arises: Are the used and useful test and the prudent investment test two distinct tests, and, if so, must both tests be satisfied before an investment will be included in the rate base?

**Prudent Investment.**[91] Prudence, according to *The Random House Dictionary*, "is care, caution, and good judgment, as well as wisdom in looking ahead."[92] Prudence thus involves foresight, not hindsight. Decisions must be judged as to their reasonableness at the time they were made and not after the fact. To quote two commissions:

> A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the

can be made concerning

*Excess Capacity*

ɪgnificance to the electric
nciples, public utilities are
ı they become "used and
ate base, including "excess
e clear that all three terms

useful referred to needed
r a plant was actually used
not, or if any expenditures
a plant would be excluded
'ul has been held by some
:husetts commission, to cite
ul standard, it must "deter-
*economically desirable.*"[89]

ınt is established if it can
ı provide either capacity
a net cost which is lower
s. Once need for capacity
ɜnergy savings has been
rmine the extent to which
to which a return should

ed and useful test and the
l, if so, must both tests be
in the rate base?
; to *The Random House Dic-*
s well as wisdom in looking
ıindsight. Decisions must be
ıey were made and not after

ɜr the company's actions,
known at the time were
ircumstances which then
may not properly be made
is it appropriate for the

PHILLIPS



> [commission] merely to substitute its best judgment for the judgments made by the company's managers.[93]
>
> The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.[94]

In their prudence investigations, commissions have disallowed an estimated $14 billion due to imprudence, generally running between 8 and 15 percent of a plant's final cost,[95] but sometimes much higher. The New York commission, for instance, found that $1.395 billion of Long Island Lighting's Shoreham plant (about 30 percent of the estimated total cost of $4.62 billion) was incurred because of construction imprudence.[96] Construction-related issues, however, are only one aspect of prudence reviews. Disallowances have been made because (1) of excess capacity (discussed below), (2) a plant should have been cancelled sooner,[97] (3) construction should not have been halted (delayed)[98] or, if halted, construction should not have been restarted,[99] (4) the capacity cost more than it should have cost in terms of alternative energy sources[100] or the optimal supply alternative,[101] and/or (5) cost overruns related to Nuclear Regulatory Commission (or other regulatory bodies) policy changes were not supported.[102] In some of these cases, it should be noted, disallowances were based upon the used and useful test; they were not found to be imprudent.[103]

**Excess Capacity.** Excess capacity has been defined as "capacity over and above that necessary to meet peak demand plus that capacity to insure that there is a margin to allow for day-to-day variations in the operating condition of installed generation."[104] For electric utilities, a 15 to 20 percent reserve margin has been viewed historically as necessary. But ever since the Arab oil embargo in 1973, the industry's reserve margin has climbed, remaining above 30 percent over the last decade (and nearer to 50 percent for some firms). Notes Studness:

> The recent frightful cost escalations of nuclear plant construction, of course, proved to be the catalyst that finally precipitated the realization that the industry's excess capacity is no longer an unavoidable product of unforeseeable events. Similarly, disallowance has emerged as the vehicle with which ratepayers are attempting to shift the costs of excess capacity onto shareholders.[105]

The possibility of excess capacity raises several regulatory problems. How, for example, should excess capacity be identified? The most common

JUNE 23, 2017

INFRASTRUCTURE

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

# Regulated Electric and Gas Utilities

Table of Contents:



Analyst Contacts:

NEW YORK +1.212.553.1653

Michael G. Haggarty +1.212.553.7172
*Associate Managing Director*
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
*Managing Director – Utilities*
james.hempstead@moodys.com

Walter Winrow +1.212.553.7943
*Managing Director - Global Project and Infrastructure Finance*
walter.winrow@moodys.com

Jeffrey Cassella +1.212.553.1665
*Vice President - Senior Analyst*
jeffrey.cassella@moodys.com

Natividad Martel +1.212.553.4561
*Vice President - Senior Analyst*
natividad.martel@moodys.com

» *contacts continued on the last page*

This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

## Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS METHODOLOGY WAS UPDATED ON THE DATES LISTED AS NOTED: ON FEBRUARY 22, 2019, WE AMENDED A REFERENCE TO A METHODOLOGY IN APPENDIX E AND REMOVED OUTDATED TEXT; ON AUGUST 2, 2018, WE MADE MINOR FORMATTING ADJUSTMENTS THROUGHOUT THE METHODOLOGY; ON FEBRUARY 15, 2018, WE CORRECTED THE FORMATTING OF THE FACTOR 4: FINANCIAL STRENGTH TABLE ON PAGE 34; AND ON SEPTEMBER 27, 2017, WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

1 This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

## About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

2 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

3 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

5 A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

## About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

### 1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

**Factor / Sub-Factor Weighting - Regulated Utilities**

| Broad Rating Factors | Broad Rating Factor Weighting | Rating Sub-Factor | Sub-Factor Weighting |
|---|---|---|---|
| Regulatory Framework | 25% | Legislative and Judicial Underpinnings of the Regulatory Framework | 12.5% |
| | | Consistency and Predictability of Regulation | 12.5% |
| Ability to Recover Costs and Earn Returns | 25% | Timeliness of Recovery of Operating and Capital Costs | 12.5% |
| | | Sufficiency of Rates and Returns | 12.5% |
| Diversification | 10% | Market Position | 5%* |
| | | Generation and Fuel Diversity | 5%** |
| Financial Strength, Key Financial Metrics | 40% | | |
| | | CFO pre-WC + Interest / Interest | 7.5% |
| | | CFO pre-WC / Debt | 15.0% |
| | | CFO pre-WC – Dividends / Debt | 10.0% |
| | | Debt/Capitalization | 7.5% |
| Total | 100% | | 100% |
| Notching Adjustment | | | |
| Holding Company Structural Subordination | | | 0 to -3 |

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

### 2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

6 For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

7 Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

## 3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

## 4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

## 5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

| Aaa | Aa | A | Baa | Ba | B | Caa | Ca |
|---|---|---|---|---|---|---|---|
| 1 | 3 | 6 | 9 | 12 | 15 | 18 | 20 |

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

**Grid-Indicated Rating**

| Grid-Indicated Rating | Aggregate Weighted Total Factor Score |
|---|---|
| Aaa | $x < 1.5$ |
| Aa1 | $1.5 \leq x < 2.5$ |
| Aa2 | $2.5 \leq x < 3.5$ |
| Aa3 | $3.5 \leq x < 4.5$ |
| A1 | $4.5 \leq x < 5.5$ |
| A2 | $5.5 \leq x < 6.5$ |
| A3 | $6.5 \leq x < 7.5$ |
| Baa1 | $7.5 \leq x < 8.5$ |
| Baa2 | $8.5 \leq x < 9.5$ |
| Baa3 | $9.5 \leq x < 10.5$ |

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

**Grid-Indicated Rating**

| Grid-Indicated Rating | Aggregate Weighted Total Factor Score |
|---|---|
| Ba1 | 10.5 ≤ x < 11.5 |
| Ba2 | 11.5 ≤ x < 12.5 |
| Ba3 | 12.5 ≤ x < 13.5 |
| B1 | 13.5 ≤ x < 14.5 |
| B2 | 14.5 ≤ x < 15.5 |
| B3 | 15.5 ≤ x < 16.5 |
| Caa1 | 16.5 ≤ x < 17.5 |
| Caa2 | 17.5 ≤ x < 18.5 |
| Caa3 | 18.5 ≤ x < 19.5 |
| Ca | x ≥ 19.5 |

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

## 6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

## Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

### Factor 1: Regulatory Framework (25%)

#### Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

### How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

## Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

| Aaa | Aa | A | Baa |
| --- | --- | --- | --- |
| Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue. |

| Ba | B | Caa |
| --- | --- | --- |
| Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting. |

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

### How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

**Factor 1b: Consistency and Predictability of Regulation (12.5%)**

| Aaa | Aa | A | Baa |
|---|---|---|---|
| The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue. | The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue. | The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue. | The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue. |

| Ba | B | Caa |
|---|---|---|
| We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions. | We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer. | We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction.<br>Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer. |

## Factor 2: Ability to Recover Costs and Earn Returns (25%)

### Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when “used and useful” requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

### How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

### How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

### How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

## Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

| Aaa | Aa | A | Baa |
|---|---|---|---|
| Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs. | Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs. | Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs. | Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs. |

| Ba | B | Caa | |
|---|---|---|---|
| There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments. | The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment. | The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention.<br><br>Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment. | |

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

**Factor 2b: Sufficiency of Rates and Returns (12.5%)**

| Aaa | Aa | A | Baa |
|---|---|---|---|
| Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned. | Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers. | Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average. | Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average. |

| Ba | B | Caa | |
|---|---|---|---|
| Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable. | We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable. | We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk.<br>Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable. | |

## Factor 3: Diversification (10%)

### Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

### How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

### How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

## Factor 3: Diversification (10%)

| Weighting 10% | Sub-Factor Weighting | Aaa | Aa | A | Baa |
|---|---|---|---|---|---|
| Market Position | 5.00% * | A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies. | Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies. | Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles. | May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates. |
| Generation and Fuel Diversity | 5.00% ** | A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below). | Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources. | Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern. | Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable. |

| | Sub-Factor Weighting | Ba | B | Caa | Definiitons |
|---|---|---|---|---|---|
| Market Position | 5.00% * | Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s). | Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s). | Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters. | Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure. |

| | | | | | |
|---|---|---|---|---|---|
| Generation and Fuel Diversity | 5.00% ** | Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress. | Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible. | Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain. | Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries). |

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

## Factor 4: Financial Strength (40%)

### Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

### How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations – Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

*CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage*

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

*CFO Pre-Working Capital / Debt*

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

*CFO Pre-Working Capital Minus Dividends / Debt*

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

*Debt/Capitalization*

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

## Factor 4: Financial Strength

| Weighting 40% | Sub-Factor Weighting | | Aaa | Aa | A | Baa | Ba | B | Caa |
|---|---|---|---|---|---|---|---|---|---|
| CFO pre-WC + Interest / Interest | 7.50% | | ≥ 8.0x | 6.0x - 8.0x | 4.5x - 6.0x | 3.0x - 4.5x | 2.0x - 3.0x | 1.0x - 2.0x | < 1.0x |
| CFO pre-WC / Debt | 15.00% | Standard Grid | ≥ 40% | 30% - 40% | 22% - 30% | 13% - 22% | 5% - 13% | 1% - 5% | < 1% |
| | | Low Business Risk Grid | ≥ 38% | 27% - 38% | 19% - 27% | 11% - 19% | 5% - 11% | 1% - 5% | < 1% |
| CFO pre-WC - Dividends / Debt | 10.00% | Standard Grid | ≥ 35% | 25% - 35% | 17% - 25% | 9% - 17% | 0% - 9% | (5%) - 0% | < (5%) |
| | | Low Business Risk Grid | ≥ 34% | 23% - 34% | 15% - 23% | 7% - 15% | 0% - 7% | (5%) - 0% | < (5%) |
| Debt / Capitalization | 7.50% | Standard Grid | < 25% | 25% - 35% | 35% - 45% | 45% - 55% | 55% - 65% | 65% - 75% | ≥ 75% |
| | | Low Business Risk Grid | < 29% | 29% - 40% | 40% - 50% | 50% - 59% | 59% - 67% | 67% - 75% | ≥ 75% |

## Notching for Structural Subordination of Holding Companies

### Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[13] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

### How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- Substantial diversity in cash flows from a variety of utility OpCos
- Meaningful dividends to HoldCo from unlevered utility OpCos
- Dependable, meaningful dividends to HoldCo from non-utility OpCos
- The group's investment program is primarily in strong utility businesses
- Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

## Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

## Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

## Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

## Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing to stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

## Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

## Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

## Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

## Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

## Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

## Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

capitalization/leverage following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

## Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

## Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

### Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

| Aaa | Aa | A | Baa |
|---|---|---|---|
| Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward- looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue. |

| Ba | B | Caa |
|---|---|---|
| Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting. | Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting. |

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

**Factor 1b: Consistency and Predictability of Regulation (12.5%)**

| Aaa | Aa | A | Baa |
|---|---|---|---|
| The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue. | The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue. | The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue. | The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue. |

| Ba | B | Caa |
|---|---|---|
| We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions. | We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays.<br>Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer. | We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction.<br>Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer. |

**Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)**

| Aaa | Aa | A | Baa |
|---|---|---|---|
| Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs. | Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs. | Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs. | Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear.<br>Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs. |

| Ba | B | Caa |
|---|---|---|
| There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments. | The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment. | The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment. |

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

**Factor 2b: Sufficiency of Rates and Returns (12.5%)**

| Aaa | Aa | A | Baa |
|---|---|---|---|
| Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned. | Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers. | Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average. | Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average. |

| Ba | B | Caa |
|---|---|---|
| Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable. | We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable. | We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable. |

## Factor 3: Diversification (10%)

| Weighting 10% | Sub-Factor Weighting | Aaa | Aa | A | Baa |
|---|---|---|---|---|---|
| Market Position | 5% * | A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies. | Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies. | Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles. | May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates. |
| Generation and Fuel Diversity | 5% ** | A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below). | Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources. | Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern. | Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable. |

| | Sub-Factor Weighting | Ba | B | Caa | Definitions |
|---|---|---|---|---|---|
| Market Position | 5% * | Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s). | Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s). | Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters. | Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure. |
| Generation and Fuel Diversity | 5% ** | Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress. | Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible. | Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain. | Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries). |

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

### Factor 4: Financial Strength

| Weighting 40% | Sub-Factor Weighting | | Aaa | Aa | A | Baa | Ba | B | Caa |
|---|---|---|---|---|---|---|---|---|---|
| CFO pre-WC + Interest / Interest | 7.5% | | ≥ 8x | 6x - 8x | 4.5x - 6x | 3x - 4.5x | 2x - 3x | 1x - 2x | < 1x |
| CFO pre-WC / Debt | 15% | Standard Grid | ≥ 40% | 30% - 40% | 22% - 30% | 13% - 22% | 5% - 13% | 1% - 5% | < 1% |
| | | Low Business Risk Grid | ≥ 38% | 27% - 38% | 19% - 27% | 11% - 19% | 5% - 11% | 1% - 5% | < 1% |
| CFO pre-WC - Dividends / Debt | 10% | Standard Grid | ≥ 35% | 25% - 35% | 17% - 25% | 9% - 17% | 0% - 9% | (5%) - 0% | < (5%) |
| | | Low Business Risk Grid | ≥ 34% | 23% - 34% | 15% - 23% | 7% - 15% | 0% - 7% | (5%) - 0% | < (5%) |
| Debt / Capitalization | 7.5% | Standard Grid | < 25% | 25% - 35% | 35% - 45% | 45% - 55% | 55% - 65% | 65% - 75% | ≥ 75% |
| | | Low Business Risk Grid | < 29% | 29% - 40% | 40% - 50% | 50% - 59% | 59% - 67% | 67% - 75% | ≥ 75% |

## Appendix B: Approach to Ratings within a Utility Family

*Typical Composition of a Utility Family*

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

*General Approach to a Utility Family*

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[16] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

*Higher Barriers to Cash Movement with Financing Predominantly at the OpCos*

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

*Lower Barriers to Cash Movement with Financing Predominantly at the OpCos*

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

## Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

**Regulated Generation Utility:** Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

**Independent System Operator:** An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

**Transmission-Only Utility:** Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

**Utility Holding Company (Utility HoldCo):** As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility HoldCos are overwhelmingly regulated electric and gas utilities.

**Hybrid Holding Company (Hybrid HoldCo)**: Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

# Appendix D: Key Industry Issues Over the Intermediate Term

## Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, larger waves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A long period of globally low interest rates, held down by monetary stimulus policies, has generally benefitted utilities, since reductions in allowed returns have been slower than reductions in incurred capital costs. Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult to predict is how regulators will respond when monetary stimulus reverses, and how well utilities will fare when fixed income investors require higher interest rates and equity investors require higher total returns and growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compression of returns has been relatively steep in recent years. In Japan, the regulatory authorities are working through the challenges presented by the decision to shut down virtually all of the country's nuclear generation capacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favored generation sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea and Thailand have been moving towards a more transparent regulatory framework. The Philippines is in the process of deregulating its power market, while Indian power utilities continue to grapple with structural challenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable, long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

## Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

## Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

## Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20$^{th}$ century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

## Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

## Appendix E: Regional and Other Considerations

### Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance on notching corporate instrument ratings based on differences in security and priority of claim, including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

### Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the securitized debt is

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

[18] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

## Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

## Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

[19] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

## Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

### PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

## Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility. In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

## Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

## Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

» contacts continued from page 1


**Analyst Contacts:**

BUENOS AIRES +54.11.5129.260

Daniela Cuan +54.11.5129.261
*Vice President - Senior Analyst*
daniela.cuan@moodys.com

TORONTO +1.416.214.163

Gavin MacFarlane +1.416.214.386
*Vice President - Senior Credit Officer*
gavin.macfarlane@moodys.com

LONDON +44.20.7772.545

Douglas Segars +44.20.7772.158
*Managing Director - Infrastructure Finance*
douglas.segars@moodys.com

Helen Francis +44.20.7772.542
*Vice President - Senior Credit Officer*
helen.francis@moodys.com

HONG KONG +852.3551.307

Vivian Tsang +852.375.815.3
*Associate Managing Director*
vivian.tsang@moodys.com

SINGAPORE +65.6398.830

Ray Tay +65.6398.830
*Vice President - Senior Credit Officer*
ray.tay@moodys.com

TOKYO +81.3.5408.410

Mihoko Manabe +81.354.084.033
*Associate Managing Director*
mihoko.manabe@moodys.com

Mariko Semetko +81.354.084.20
*Vice President - Senior Credit Officer*
mariko.semetko@moodys.com

Report Number: 1072530

Author
Michael G. Haggarty

Production Associate
Masaki Shiomi

JUNE 18, 2010

GLOBAL INFRASTRUCTURE FINANCE

MOODY'S
INVESTORS SERVICE

SPECIAL COMMENT

# Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality

## Evaluating a Utility's Ability to Recover Costs and Earn Returns

Table of Contents:



Analyst Contacts:

NEW YORK 1.212.553.1653

Michael G. Haggarty 1.212.553.7172
*Senior Vice President*
Michael.Haggarty@moodys.com

Joseph Vinciguerra 1.212.553.4137
*Associate Analyst*
Joseph.Vinciguerra@moodys.com

William L. Hess 1.212.553.3837
*Team Managing Director*
William.Hess@moodys.com

*» Analyst contacts continued on the last page*

## Summary

A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings. In Moody's Regulated Electric and Gas Utilities Rating Methodology, published in August 2009 (the Rating Methodology), these concepts are incorporated as the second of four key factors utilized to determine credit ratings in the regulated utility sector. The criteria we consider when analyzing this factor include the statutory and regulatory provisions in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery of costs, precluding any possibility of legal challenges to rate increases or cost recovery mechanisms. Such strong statutory protections are most often found in very supportive and protected regulatory environments like Japan and Hong Kong, for example. In the U.S., however, the ability to recover costs and earn returns is much less certain and can be subject to intense public and sometimes political scrutiny, and such provisions vary among state jurisdictions. Consequently, the analysis of a U.S. based utility's cost recovery and return provisions is more complicated. This Special Comment discusses the criteria we use to determine how a utility is scored in the cost recovery and return factor in our ratings methodology.

One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.

Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. Many of these clauses are annual but they can also be semiannual, quarterly, or monthly. The scope of automatic adjustment clauses has expanded over the years and now covers costs as diverse as transmission, generation, renewable energy, environmental compliance, pensions and bad debt. Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.

Other considerations when analyzing cost recovery include the test year used, regulatory pre-approvals, and the inclusion of construction work in progress (CWIP) in rate base. Forward test years are generally better predictors of future utility conditions than historical test years, and their usage is more likely to reduce regulatory lag. Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.

Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. Decoupling mechanisms to "de-link" utility revenues and profits from volumes are essential to credit quality if energy efficiency and demand side management programs become more prevalent in the sector as anticipated. Finally, the option to issue cost recovery bonds to securitize large or unexpected costs, like those from storms, is another way that a utility can recover its costs and avoid the rate shock that could result if such costs are passed on to ratepayers over a limited time frame.

## Introduction

In Moody's Rating Methodology, the cost recovery provisions a utility has in place, as well as the return it earns, are important determinants of a utility's rating and overall credit quality. These concepts are incorporated into the ratings methodology as the second of four key factors we use to determine ratings in the regulated electric and gas utility sector. A utility's ability to recover its costs and earn a return represents a significant 25% of the overall weighting[1] of the factors used to determine a utility's credit rating. Unlike Factor 1, Regulatory Framework, which considers the general regulatory environment under which a utility operates and the overall position of a utility within that regulatory environment, Factor 2 addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

[1] The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring does not include every consideration that determines a rating.

*TABLE 1*

**Regulated Electric and Gas Utility Rating Methodology**

| KEY RATING FACTORS AND WEIGHTINGS |
|---|
| 1. Regulatory Framework – 25% |
| 2. Ability to Recover Costs and Earn Returns – 25% |
| 3. Diversification – 10% |
| 4. Financial Strength and Liquidity – 40% |

The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated electric and gas utilities, especially since the lack of timely recovery of costs has caused severe financial stress for utilities on several occasions. In five of the seven major investor owned utility defaults in the United States over the last 50 years, regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investments ultimately led to financial pressure and credit rating downgrades. The reluctance to provide rate relief in some cases reflected regulatory commission concerns about the impact of large rate increases on customers as well as concerns about the appropriateness and prudency of the relief being sought by a utility. Currently, given the utility industry's sizable capital expenditure requirements for infrastructure needs and environmental compliance, there is likely to be a growing and ongoing need for rate relief to recover these expenditures, at a time when economic conditions may limit the ability or willingness of regulators to provide this timely rate relief. Regulators also need to balance the amount of rate relief granted to utilities with consumers' ability to absorb these costs.

For regulated utilities, the criteria we consider in assessing Factor 2 include the statutory protections in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan and Hong Kong, for example.

More typically, however, and as is characteristic of most utilities in the U.S. and elsewhere in Asia, the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost adjustment clauses or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score in the A category for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa score for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

Most of the utilities in Central and Eastern Europe (CEE) inherited oversized, outdated and underinvested infrastructure, built during previous communist regimes. Furthermore, those infrastructure assets are very often highly depreciated. Therefore, the main regulatory challenges for the CEE region lies rather in the area of full recovery of investment costs, including the establishment of appropriate regulatory asset bases and the determination of reasonable regulatory depreciation levels (which would be included in allowable costs to be recovered), rather than fine-tuning the actual level of return. Indeed, there is a very similar issue confronting South Africa, where there has been a long period of underinvestment in electricity assets. The approach towards the determination of the regulated asset base and treatment of asset revaluations differ significantly across the developing markets and could impact utilities' ability to generate sufficient funds for future investment in new assets.

The following is a discussion of the key factors we consider when scoring Factor 2, "Ability to Recover Cost and Earn Returns", in our Rating Methodology. The current Factor 2 scoring for the operating utilities in our rated universe is shown in Appendix A. These Factor 2 scores provide in indication of our current thinking. The scores are not intended to be static and continue to be monitored and modified as warranted to reflect changing conditions and circumstances, particularly as new rate cases are decided and cost recovery provisions evolve. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

## Return on Equity and Regulatory Lag

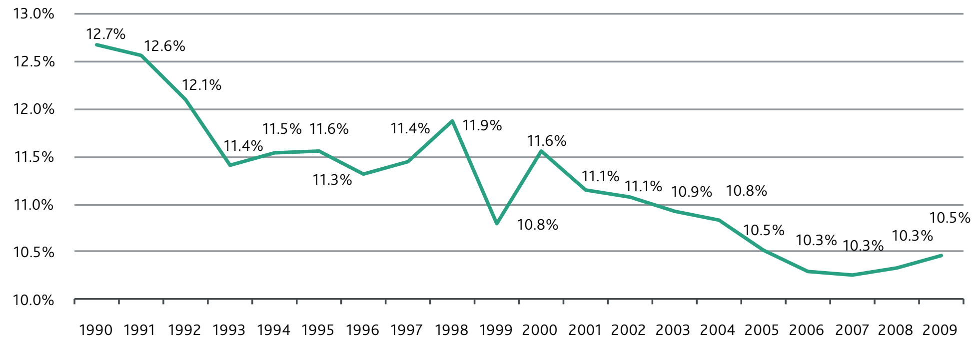
A utility's allowed return on equity (ROE) is one of the most obvious but potentially misleading statistics used to judge if a utility is recovering its costs and earning an adequate return. High ROE's are typically better than low ROE's, one reason that the timely, forward looking regulation of the Federal Energy Regulatory Commission (FERC) is viewed as more supportive, with ROE's that can be 12% or higher. In theory, if a utility's allowed return on equity is set at a high level, its earned return should also be high, leading to higher equity values, lower costs in relation to revenues, and ultimately higher credit ratings. This framework exists for some investor owned utilities, with high ROE's equating to good earnings and strong metrics, although this is not always the case. Earned ROE's are important in that they help to measure management's ability to operate their utility system within a given regulatory structure. A low allowed ROE is often associated with low earned ROE's, thereby affecting net income, lowering retained cash flow, depressing equity values, and raising financing costs.

However, the relationship between a utility's allowed return on equity and its ability to recover its costs and earn an adequate return is not as simple or clear cut as it may appear. A utility may have a low allowed ROE but be permitted to recover many of its operating costs through automatic adjustment clauses and other trackers, reducing risk and mitigating the impact of a low ROE. On the other hand, a utility may be permitted a high allowed ROE, but because of the higher than average risks associated with operating within this jurisdiction, the absence of such cost recovery provisions, overly long rate cases, or significant regulatory lag, may never actually earn its allowed return. According to the Edison Electric Institute, the average regulatory lag in the utilities industry is 11 months, close to where it has been for most of the last two decades. Adequate liquidity reserves on the part of utilities should mitigate some of the risks associated with regulatory lag.

While it is important to establish a link between a utility's regulatory allowed ROE and its automatic adjustment cost recovery clauses, it is also important to associate its authorized ROE with the sales forecast underlying the return. On its face, a high allowed ROE may appear favorable, although the return may be premised on a historic test year in which a high level of sales was achieved, which may not reoccur. This scenario could occur if there is a subsequent economic recession, unexpected financial shock, or lower usage on the part of the utility's customers due to high electric and/or gas rates or energy conservation. In such a case, a utility with a higher allowed ROE may be no better positioned than a utility with a lower allowed ROE based on a more achievable sales forecast. Allowed ROE's generate headline news, and market participants often gauge, at first blush, a utility's treatment in a rate case by this measure. However, the allowed ROE should not be viewed in isolation, but must be evaluated within the context of a utility's overall cost recovery provisions.

*FIGURE 1*

**Average Awarded Electric ROE**




*Source: Regulatory Research Associates, a subsidiary of SNL Financial ,LLC, Edison Electric Institute*

While regulatory lag has been stable, the long-term trend in allowed ROE's over the last two decades has been down, with the average allowed ROE falling from the 12% to 13% range in the early 1990's to the 10% to 10.5% range in recent years. In some cases, utility allowed ROE's have dropped below 10%. Not surprisingly, the average requested ROE has exhibited a similar trend, falling from as high as 13.5% in the early 1990's to approximately 11.2% in the first quarter of 2010. While some of the decrease in ROE's can be attributed to falling interest rates over the period, some can also be attributed to the other mechanisms that utilities have put in place to ensure timely cost recovery and maintain adequate returns, many of which are discussed below.

Some regulators view mechanisms such as cost recovery provisions and other automatic cost adjustment clauses as materially reducing the business and operating risk of some utilities, thereby justifying a lower return on equity. While there may be some merit to this argument, the relationship between these mechanisms and return on equity is complicated. Many of these provisions are "earnings neutral" but can have a cash impact, positive or negative, which could affect cash flow coverages and credit quality. Similarly, the increasing prevalence of formula based ratemaking and formula rate plans, where capital projects and other major revenue based changes are automatically incorporated into rates, have also caused some regulatory commissions to approve lower ROE's. However, a well structured formula rate plan could also lead to rate reductions if a utility is earning above its allowed range and in such cases, a lower allowed ROE may not be justified. Using ROE alone as a basis to compare utilities that operate under varying conditions and in different regulatory environments can be problematic and overly simplistic. Other considerations that may lead to widely different ROE's among utilities include the type of utility (whether vertically integrated or transmission and distribution), the mix of plants it operates, the size of its capital expenditure program, the risks associated with operating in a certain jurisdiction or building certain assets, demand and economic conditions within its service territory, and the utility's overall balance of debt and equity.

## Fuel, Purchased Power and Other Automatic Cost Adjustment Clauses

Among the most common cost recovery provisions in the regulated utility sector are automatic adjustment clauses and other cost trackers (also referred to as riders or true-ups) for the recovery of costs outside of traditional base rate cases. The most prevalent type of such clauses are fuel adjustment clauses (FAC's) in the electric sector and purchase gas adjustments (PGA's) in the gas sector. These generally permit automatic changes in rates in response to movements in the price of fuels used in the generation of electricity and in the price of purchased gas for local distribution companies. Moody's views automatic adjustment clauses as supportive of utility credit quality and important in reducing utility cash flow volatility and liquidity requirements. These clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. They also reduce the level of regulatory uncertainty for the recovery of these costs by ensuring, through regulatory or statutory means, their recovery up-front.

Important considerations when analyzing such clauses include the frequency of true-up calculations and the period of time over which revenue variances are recovered. For example, Consolidated Edison Company of New York's purchased power cost variances are calculated monthly and recovered or refunded generally within one or two months. Some gas LDC's have quarterly gas cost adjustments; some vertically integrated utilities calculate fuel variances annually and recover these costs the following year, while others may recover some costs over a longer time period. In general, more frequent variance calculations and shorter recovery periods are considered more supportive of credit quality, limiting the potential for the accumulation of large deferral balances, the recovery of which could result in rate shock for consumers, as well as liquidity and working capital stress.

**Adjustment Clauses as Regulatory Policy**

Fuel adjustment clauses became prevalent in the U.S. in the 1970's when dramatically higher oil prices severely affected the cash flows of several utilities, when the industry was much more reliant on oil as a source of fuel for generation than it is today. During this time, oil prices rose so quickly that traditional base rate proceedings, with their lengthy time schedules, were unable to address cost recovery in a timely manner, severely stressing the cash flows of several utilities. Since that time, most U.S. states have permitted their utilities to automatically adjust fuel related rates outside of a formal base rate proceeding. In Missouri, one of the few states that historically did not have a fuel adjustment clause, legislation was passed in 2005 permitting the Missouri Public Service Commission to implement such a clause. In Ohio, fuel recovery was recently granted to AEP's Ohio Power subsidiary, although Duke Energy Ohio has had one in place for years.

Volume risk and purchase cost adjustments emerged as important regulatory topics in Central and Eastern Europe (CEE) only after the increase in the volatility of energy prices and unprecedented declines of energy consumption caused by the recent recession. The approach of respective CEE regulatory bodies varied from strong opposition to timely adjustments, mostly motivated by social considerations (i.e. Poland, Slovakia), to incorporation of automatic fuel and purchase adjustment mechanisms into regulation. Surprisingly, the regulatory regimes of Baltic countries, where the recession took the greatest toll, showed relatively solid resilience to political interference and allowed the local dominant electric utilities (the Latvian Latvenergo and the Estonian Eesti Energia) to pass through costs from fluctuating fuel input prices, thus allowing them to generate sufficient cash flows even in times of significant economic readjustment; this justifies their scoring of A in this factor.

In Korea, KEPCO's financial performance suffered significant deterioration in 2008 as a result of exposure to contracted high fuel costs and sharp depreciation of the Korean Won. The government stepped in and approved a 4.5% tariff increase and a KRW668 billion one-off subsidy to offset its losses due to high fuel costs and currency devaluation. The government is also considering implementing an automatic cost pass through mechanism in due course.

Automatic adjustment clauses are typically aimed at mitigating the effects of highly variable costs, such as fuel and purchased power, which are typically the largest component of utility operating expenses. These costs have been particularly volatile over the last several years, a time when the industry has become more exposed to both natural gas and coal prices. This exposure was again highlighted in late 2005 when two major hurricanes severely disrupted natural gas production in the Gulf Coast region, leading to a sudden and sustained increase in natural gas prices. Such costs are for the most part out of the utility's control, although some try to manage them by hedging their fuel supply to some degree. However, both the magnitude and volatility of these costs make fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms in the industry.

In some cases, fuel adjustment clauses may be limited in scope or subject to regulatory review to ensure that the costs that are incurred are prudent. Some states allow rate adjustments within certain ranges or bandwidths, with any costs incurred outside of these ranges deferred for recovery in subsequent base rate cases. Cost deferred and recovered through later base rate cases depress cash flow and inevitably add to regulatory lag, a short-term issue that should not negatively affect long-term credit quality

Fuel adjustment clauses, which also include purchased power costs, have also become critical to transmission and distribution utilities that no longer own generation assets following the deregulation of electricity markets in their states. Many of these companies are responsible for procuring power for their retail customers as part of their Provider of Last Resort or POLR obligations and, as a result, are responsible for procuring their generation requirements in the wholesale power markets. The lack of a prompt and timely generation cost adjustment clause or similar pass-through mechanism can have a detrimental effect on transmission and distribution utility cash flows and credit quality.

Automatic adjustment clauses and other pass-through mechanisms have been expanded over the years and now cover costs as diverse as transmission, new generation, renewable energy, environmental compliance costs, demand side management and energy efficiency costs, pensions, and bad debt expenses. These clauses may also be put in place for more unusual or extraordinary costs such as those incurred as a result of hurricanes or ice storms. In some states, changes in interest expense relative to what had been incorporated into existing rates have also been covered by such clauses. Like fuel and purchased power adjustment clauses, these other clauses are likely to increase the likelihood of timely recovery of prudently incurred costs, reduce regulatory uncertainty, and lead to a higher score for a utility's cost recovery factor in our ratings methodology.

## Forecast Risk – Historical Versus Forward Test Years

In most utility ratemaking procedures, the selection of a test year is an important consideration in determining both the level of adjustments to rates that may be necessary later and the degree of regulatory lag the may result. A test year is the base year in which a forecast of a utility's operations and investment requirements over a twelve month period is devised. It is supposed to be representative of what costs will be incurred by a utility during an upcoming period, and establish what additional rate adjustments a utility will need to cover costs and earn an adequate rate of return. Depending on the regulatory provisions of a particular state, utilities are generally required to use either a historical test year or a future test year. In some cases, a combination or "hybrid" of these two test year periods can be used, with "known and measurable" adjustments.

A historical test year utilizes a twelve month period before the current rate filing as the basis for determining future rates. Some state regulatory commissions prefer historic tests years because the information used in determining rates is based on actual data that can be easily measured and analyzed.

However, in situations where industry conditions are changing rapidly, such as when costs are increasing or capital expenditures growing, historical test years are generally less useful as an accurate data point for setting future rates. In addition, the use of historical test years can contribute to regulatory lag in that a utility must usually file another rate case to recover those costs not accurately predicted with the use of the historical test year. As a result, utilities that use historical test years typically do not earn their allowed rate of return on an ongoing basis and experience persistent regulatory lag in the recovery of costs.

The use of a forward (or future) test year, while not a perfect predictor of future utility revenue requirements, strives to use the most timely and up-to-date information available in setting rates. Forward test years are typically based on forecasts of future costs and expenses, often leading to a high degree of scrutiny by regulators on the financial models and assumptions used in creating these forecasts. While all forecasts have limitations, forward test years are generally better predictors of future utility conditions than historical test years, especially where there are rapidly changing industry conditions. Forward test years can better incorporate current and expected economic conditions, a utility's capital expenditure budget going forward, and projected changes to a utility's customer base or load growth forecasts, for example. Moreover, forward test years help to reduce regulatory lag and ensure that a utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's views the use of forward test years as more supportive of utility credit quality than historical test years.

## Regulatory Pre-Approvals

The utilities industry is in the midst of a substantial capital expenditure program, with significant investment planned in all aspects of its business, including generation, transmission, and distribution, as well as for substantial environmental compliance expenditures. Because of the size and complexity of many of these projects, Moody's places a high degree of emphasis on the regulatory certainty for the recovery of such costs, which is critical for the maintenance of utility credit quality. For some of these projects, especially when considering added uncertainty related to the economy and the timing of future laws and regulations related to carbon, it will be viewed as a significant credit positive if utilities are able to obtain regulatory support for recovery in advance. This would serve to limit regulatory risk associated with eventual disallowance or nonrecovery of already expended costs. Some U.S. states, including Idaho, Iowa, Virginia, and Wisconsin, have passed legislation pre-approving some generation costs and outlining cost recovery provisions for new plant construction, which Moody's considers to be a positive regulatory development for the utilities in those states. In India, the construction of Ultra Mega Power Projects do not have any cost recovery provisions, but are rather based on competitive tariff structures. Pre-approval of purchased power agreements would also be considered positively from a credit standpoint.

Approval of future project capital expenditures in advance requires a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service. In order for a state regulatory commission to pre-approve costs for a large and complex project, it is necessary for the commission and commission staff to gain an understanding of the project, including the need for the project, the construction budget, and the financing plan. Some projects underway right now, such as new nuclear construction, are expensive, complex, and multi-year in scope, and may not have been undertaken at all if regulators were not on board with the prudency of their projected costs and timetable in advance.

Regulatory pre-approval of utility capital expenditures may include incentives, mandated completion dates, or caps on the aggregate amount of recovery, giving state regulators some control over the ultimate costs and thus limiting ratepayer exposure in the event there are cost overruns or delays. In some cases, utilities may seek pre-approval for capital expenditures on a regular basis, such as annually or semi-annually, throughout the project's construction period. For example, for the recovery of costs related to Georgia Power's new nuclear construction project at its Vogtle plant site, the utility files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC), with the GPSC reviewing and approving project costs on an ongoing basis. South Carolina Electric & Gas has a similar arrangement with the South Carolina Public Service Commission (SCPSC) for new nuclear construction at its Summer plant site. In order for such a pre-approval arrangement to be effective, however, state commissions need to have the time, ability, and resources to properly evaluate a complex project's construction progress, as well as any potential delays or problems that may arise. The Indiana Utility Regulatory Commission, for example, has an engineer advising them on Duke Indiana's Edwardsport project. Moody's views such collaborative utility-regulatory commission relationships as positive and important in insuring that prudent project costs are eventually recovered. They also serve to limit, but not fully protect against, the risk that there will be significant stranded, disallowed or otherwise unrecovered expenditures.

## Construction Work in Progress (CWIP) in Rate Base/Concurrent Recovery

"Construction work in progress" (CWIP) represents the cost of capital projects that are under construction but not yet in service and considered "used-and-useful" in the provision of electric and/or gas service. Under traditional utility ratemaking, these costs cannot be included in customer rates until a project is completed and fully operational. However, because of the long lead times and large cost of many utility construction projects, some utilities are permitted by regulators to include CWIP in rate base, allowing it to earn a cash return on the project while it is under construction. The alternative would be for a utility to accumulate the financing costs on CWIP over the construction period (called "allowance for funds used during construction" or AFUDC) and include them in rates when the project is completed. Proponents of this approach generally argue that it is appropriate for utility ratepayers to pay only for projects that are in use and currently benefiting them through the provision of electricity and/or gas.

Moody's views the inclusion of CWIP in rate base as supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and potentially unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether.

It should be noted that not all CWIP recovery provisions are the same. Some state regulatory commissions only allow a portion of CWIP to be included in rate base, some only allow a debt return, while others allow a full weighted average cost of capital return. From a credit perspective, inclusion of all CWIP in rate base at a full weighted average cost of capital return would be considered the most supportive CWIP recovery provision.

Whether to allow CWIP in rate base became a significant issue several years ago, particularly during the last round of nuclear construction in the 1970's, when a number of utilities were engaged in major nuclear construction projects and substantial cost overruns were commonplace. This was also an era of high inflation and high interest rates, exacerbating the rate impact of allowing CWIP in rate base. Because of this experience, a few states actually passed laws prohibiting utilities from including CWIP in rate base, some of which are still on the books today. The issue has again come to the forefront with the advent of major new nuclear construction in the U.S., and also because of large capital expenditure plans for transmission, renewable energy projects, integrated gasification combined-cycle (IGCC) plants, and environmental compliance requirements. Although the treatment of CWIP by individual state regulatory commissions varies, most states do allow for the inclusion of some or all of CWIP in rate base, a credit positive. Those states that do not allow the inclusion of CWIP in rate base, either by law or by recent commission decision, are listed below.

*TABLE 2*

**States Not Allowing CWIP in Rate Base**

| LEGALLY PROHIBITED | DENIED BY COMMISSION |
|---|---|
| Connecticut | Arizona |
| Missouri | Nebraska |
| New Hampshire | Oklahoma |
| Oregon | Rhode Island |
| Pennsylvania | |

The inclusion of CWIP in rate base is an especially important credit supportive measure for those utilities in the process of constructing new nuclear plants. In Georgia and Florida, for example, legislation passed over the last few years allows utilities in both states to earn a cash return on CWIP for new nuclear construction. For Georgia Power, the inclusion of CWIP in rate base and the recovery of financing costs on its new Vogtle nuclear construction project reduced the project's in-service cost to $4.5 billion from $6.4 billion. Similarly, in South Carolina, the Public Service Commission has authorized South Carolina Electric & Gas to earn a cash return on CWIP associated with new nuclear construction in that state. In contrast, in early 2009, Ameren subsidiary AmerenUE suspended efforts to build a new nuclear plant in Missouri after legislation allowing CWIP in rate base was not passed by the Missouri General Assembly.

As previously mentioned, the less favorable alternative to inclusion of CWIP in rate base from a credit standpoint is allowance for funds used during construction (AFUDC) accounting treatment for construction projects. With AFUDC, capital projects do not earn a cash return during the construction phase, but do when they become used and useful. Because of the long lead times and large cost of many utility construction projects, this can place great financial and liquidity pressure on utilities. Under AFUDC accounting conventions, a utility's earnings are made whole by non-cash earnings, offsetting the incremental debt and equity capital costs incurred to finance the projects. While there is no earnings impact on a utility income statement, cash flow generally lags while debt mounts, a credit negative. Some opponents to AFUDC treatment argue that rate payers generally face a larger one-time rate increase under this approach than if CWIP treatment was applied.

## Interim Rate Relief

Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is often an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. While some states allow utilities to petition for interim rate relief, others only permit such relief in extraordinary or emergency situations, limiting its use to unusually dire circumstances. Interim rate relief is also difficult for state regulators to grant when there are poor economic conditions in a utility's service territory, and some requests for interim rate relief are declined for these reasons. Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration. The existence of a maximum timeframe for decisions on interim (or general) rate cases is another important credit consideration. If there is no statutory time limit for rendering such rate case decisions, regulatory lag can result.

In Florida, utilities may request an interim rate increase only if they have petitioned the Florida Public Service Commission (FPSC) for a permanent base rate increase. In its most recent rate case, for example, Progress Energy Florida requested and was granted an interim rate increase to recover the costs of repowering one of its generating units to natural gas from oil. The interim rates were put in effect during the course of the base rate proceeding, which in Florida takes about nine months. Interim rates are credited back to customers, with interest, if the FPSC determines in its final rate decision that the interim rates were not justified. In Hawaii, interim rates must be enacted within 11 months of filing, but there is no statutory time limit for a final decision. As such, the majority of Hawaiian Electric rate decisions in recent years have been interim decisions.

In West Virginia, Appalachian Power and Wheeling Power, both subsidiaries of American Electric Power (AEP), requested an interim rate increase of $180 million in April 2009, out of an overall $442 million rate increase request, for fuel, purchased power, and environmental compliance project expenses. Because of sharply higher fuel costs, the company was paying more for fuel than it was receiving in existing rates and hoped the interim rates would offset a growing fuel underrecovery. On June 4, 2009, the Public Service Commission of West Virginia denied the request, citing the potential for financial hardship on customers, especially during currently difficult economic times. The denial of interim rate relief is considered a credit negative in that it added to fuel underrecoveries and increased regulatory lag at the utilities.

## Volume Risk and Decoupling

There has been a great deal of emphasis and attention in recent years given to energy efficiency and demand side management programs aimed at reducing the consumption of electricity and natural gas both because of environmental concerns and for economic reasons. For utilities these efforts represent a potential threat to cost recovery because under traditional rate of return regulation, utility revenues are a function of the volume of power and energy is sold, i.e. all or a portion of the utility's fixed costs are recovered through volumetric charges. Consequently, utilities that are dependent on volume are, in fact, economically motivated to encourage higher energy usage instead of conservation and energy efficiency. Decoupling is aimed at "de-linking" a utility's revenues and profits from volume and at the same time compensating utilities for promoting less energy use.

Decoupling has become more prevalent over the last year since the Federal government's economic stimulus bill was passed in February 2009. That bill provides significant funding to states to promote and encourage energy efficiency programs, but only in the event there are incentives in place for utilities themselves to encourage and promote such programs. There are still relatively few states with decoupling measures in place for electric utilities, although they have been more common for gas utilities. Moody's views decoupling measures as important to the maintenance of utility credit quality in states where energy efficiency and demand side management programs could put pressure on utility sales volumes, operating margins, and cash flow coverage metrics.

*TABLE 3*

**Selected States With Decoupling Measures in Place**

| ELECTRIC DECOUPLING | GAS DECOUPLING |
|---|---|
| California | Arkansas |
| Connecticut | California |
| Idaho | Colorado |
| Maryland | Illinois |
| Massachusetts | Indiana |
| Michigan | Maryland |
| New Hampshire | Massachusetts |
| New York | Michigan |
| Oregon | Minnesota |
| Vermont | New Jersey |
| | New York |
| | Nevada |
| | North Carolina |
| | Ohio |
| | Oregon |
| | Utah |
| | Virginia |
| | Washington |
| | Wisconsin |
| | Wyoming |

The state of California was at the forefront of states adopting decoupling as far back as 1982, when it put an Electric Revenue Adjustment Mechanism in place, which de-linked utility revenues from utility sales to promote energy conservation. Other states have introduced decoupling more recently, including Idaho, Maryland, Massachusetts, and New York. Some states have partial decoupling measures in place, such as New Hampshire, which allows decoupling for generation and transmission, but not for distribution. Hawaii has recently approved a decoupling mechanism, which is most similar to the California model, but it has yet to be fully implemented into electric rates. Many more states are considering decoupling measures and Moody's expects such measures to become increasingly prevalent as energy efficiency and demand side management programs are increasingly emphasized.

## Cost Recovery Bonds (Securitization)

Since the late 1990's, legislatively approved stranded cost, storm cost, and other cost recovery bonds have been issued to reimburse utilities for costs related to deregulation, hurricanes, environmental compliance, and energy supply. In its simplest form, a securitization is a type of irrevocable rate order that authorizes and dedicates a stream of cash flow to service bonds issued to reimburse utilities for specific costs. Such bonds were originally issued to compensate utilities for stranded costs following the deregulation of the energy markets in some states several years ago. More recently, storm-related securitizations have been completed following active hurricane seasons in 2004, 2005 and 2008 along the Gulf Coast region and in Florida. Securitization bonds have also been issued to finance environmental compliance costs in West Virginia.

Cost recovery bonds represent another way that regulatory commissions and state legislatures can assure that a utility receives adequate recovery for sometimes large and unanticipated capital expenditures, while avoiding the rate shock that could result from passing through all these costs over a limited time frame. Instead, cost recovery bonds allow these costs to be spread out and financed over a multi-year period. Customers benefit from the low financing costs that characterize such bonds, since the special purpose entities issuing the bonds are typically rated Aaa, and the utility is reimbursed for the costs it incurred fairly quickly when the bonds are issued, reducing regulatory lag. However, Moody's notes that some storm cost recovery bonds have been issued as long as two to three years after the costs have been incurred, in some cases due to the need to pass legislation authorizing such bonds. Such legislation is necessary to insure that the collection of the cost recovery bond surcharge is statutorily protected, irrevocable, and non-bypassable. Moody's views utilities that have the option of issuing cost recovery bonds in the event of large, unexpected, or extraordinary costs more favorably from a credit point of view.

## Conclusion

Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures, construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.

## Appendix A: Current Factor 2 Scoring for the operating utilities in Moody's rated universe

### Vertically Integrated Utilities

| Aaa | Aa | A | Baa | Ba | B |
|---|---|---|---|---|---|
| Tennessee Valley Authority | Chubu Electric Power Company, Incorp. | Alabama Power Company | ALLETE, Inc. | Companhia Energetica de Minas Gerais - CEMIG | Perusahaan Listrik Negara (P.T.) |
| | Chugoku Electric Power Company, Incorp. | Consumers Energy Company | Appalachian Power Company | Cemig Geracao e Transmissao S.A. | |
| | CLP Power Hong Kong Limited | Dayton Power & Light Company | Arizona Public Service Company | Companhia Paranaense de Energia - COPEL | |
| | Electric Power Delevopment Co., Ltd. | Detroit Edison Company (The) | Black Hills Power, Inc. | EDP – Energias do Brasil | |
| | Hokkaido Electric Power Company, Incorp. | Duke Energy Carolinas, LLC | Central Vermont Public Service Corp. | Empresas Publicas de Medelin E.S.P. | |
| | Hokuriku Electric Power Company | Duke Energy Indiana, Inc. | Cleco Power LLC | Entergy Texas | |
| | Kansai Electric Power Company, Incorp. | Florida Power & Light Company | Columbus Southern Power Company | Eskom Holdings Ltd | |
| | Kyushu Electric Power Company, Incorp. | FortisBC Inc | Duke Energy Kentucky, Inc. | Furnas Centrais Electricas S.A. | |
| | Okinawa Electric Power Company, Incorp. | Georgia Power Company | Duke Energy Ohio, Inc. | Israel Electric Corporation Limited (The) | |
| | Osaka Gas Co., Ltd. | Gulf Power Company | EDA - Electricidade dos Acores, S.A. | Light S.A. | |
| | Tokyo Electric Power Company, Incorp. | Indianapolis Power & Light Company | Eesti Energia AS | NTPC Limited | |
| | Tokyo Gas Co., Ltd. | Interstate Power & Light Company | El Paso Electric Company | Tata Power Company Limited (The) | |
| | | Kentucky Utilities Co. | Empire District Electric Company (The) | Union Electric Company | |
| | | Louisville Gas & Electric Company | Empresa de Electricidade da Madeira, S.A. | | |
| | | Madison Gas and Electric Company | Entergy Arkansas, Inc. | | |
| | | MidAmerican Energy Company | Entergy Gulf States Louisiana, LLC | | |
| | | Mississippi Power Company | Entergy Louisiana, LLC | | |
| | | Northern Indiana Public Service | Entergy Mississippi, Inc. | | |
| | | Northern States Power Company (Minnesota) | Entergy New Orleans, Inc. | | |
| | | Northern States Power Company (Wisconsin) | Hawaiian Electric Company, Inc. | | |
| | | Oklahoma Gas & Electric Company | Hydro-Québec | | |
| | | Pacific Gas & Electric Company | Idaho Power Company | | |
| | | Progress Energy Carolinas, Inc. | Indiana Michigan Power Company | | |
| | | Progress Energy Florida, Inc. | Kansas City Power & Light Company | | |
| | | Public Service Company of Colorado | Kentucky Power Company | | |
| | | South Carolina Electric & Gas Company | Korea Electric Power Corporation | | |
| | | Southern California Edison Company | Latvenergo | | |
| | | Southern Indiana Gas & Electric | Monongahela Power Company | | |
| | | Superior Water, Light and Power Company | Nevada Power Company | | |

### Vertically Integrated Utilities

| Aaa | Aa | A | Baa | Ba | B |
|---|---|---|---|---|---|
| | | Tampa Electric Company | NorthWestern Corporation | | |
| | | Virginia Electric and Power Company | Ohio Power Company | | |
| | | Wisconsin Electric Power Company | Otter Tail Corporation | | |
| | | Wisconsin Power and Light Company | PacifiCorp | | |
| | | Wisconsin Public Service Corporation | Portland General Electric Company | | |
| | | | Public Service Company of New Hampshire | | |
| | | | Public Service Company of New Mexico | | |
| | | | Public Service Company of Oklahoma | | |
| | | | Puget Sound Energy, Inc. | | |
| | | | Sierra Pacific Power Company | | |
| | | | Southwestern Electric Power Company | | |
| | | | Southwestern Public Service Company | | |
| | | | Taiwan Power Company Limited | | |
| | | | Tenaga Nasional Berhad | | |
| | | | Tucson Electric Power Company | | |
| | | | UNS Electric | | |

### T&D Utilities

| Aa | A | Baa | Ba | B |
|---|---|---|---|---|
| Hong Kong and China Gas Co. Ltd | AEP Texas Central Company | Atlantic City Electric Company | AES Eletropaulo | Edenor S.A. |
| Oman Power and Water Procur. Co. | AEP Texas North Company | Baltimore Gas and Electric Company | AES El Salvado Trust | |
| | CenterPoint Energy Houston Electric, LLC | Central Illinois Light Company | Bandeirante Energia S.A. | |
| | Central Hudson Gas & Electric Corporation | Central Illinois Public Service Company | Cemig Distribuicao S.A. | |
| | Central Maine Power Company | Cleveland Electric Illuminating Company (The) | Centrais Eletricas do Para S.A. | |
| | Consolidated Edison Company of New York, Inc. | Commonwealth Edison Company | Centrais Eletricas Matogrossenses S.A. | |
| | FortisAlberta Inc. | Connecticut Light and Power Company | Comp. de Ener. Eletr. do Est. do Tocantins | |
| | Hydro One Inc. | Delmarva Power & Light Company | Espirito Santo Centrais Eletricas - ESCELSA | |
| | Massachusetts Electric Company | Duquesne Light Company | Ejesa S.A. | |
| | New England Power Company | Illinois Power Company | Empresa Electrica de Guatemala, S.A. | |
| | Newfoundland Power Inc. | Jersey Central Power & Light Company | Energisa Paraíba-Dist. de Energia S.A. | |
| | Niagara Mohawk Power Corporation | Metropolitan Edison Company | Energisa Sergipe - Dist. de Energia S.A. | |
| | NSTAR Electric Company | Narragansett Electric Company | Gas Authority Inida Limited | |
| | Oncor Electric Delivery Company | New York State Electric and Gas Corporation | Light Serviços de Eletricidade S.A. | |
| | Orange and Rockland Utilities, Inc. | Ohio Edison Company | Perusahaan Gas Negara | |
| | Public Service Electric and Gas Company | PECO Energy Company | Rede Energia | |
| | San Diego Gas & Electric Company | Pennsylvania Electric Company | Rio Grande Energia S.A. - RGE | |
| | | Pennsylvania Power Company | Towngas China Co. Ltd | |
| | | Potomac Edison Company (The) | Xinao Gas Holdings Ltd | |
| | | Potomac Electric Power Company | | |
| | | PPL Electric Utilities Corporation | | |
| | | Rochester Gas & Electric Corporation | | |
| | | Texas-New Mexico Power Company | | |
| | | Toledo Edison Company | | |
| | | United Illuminating Company | | |
| | | West Penn Power Company | | |
| | | Western Massachusetts Electric Company | | |

## Transmission Only Utilities

| A |
|---|
| American Transmission Company LLC |
| American Transmission Systems |
| International Transmission Company |
| ITC Midwest LLC |
| Michigan Electric Transmission Company |
| Trans-Allegheny Interstate Line Company |

## Local Gas Distribution Companies (LDCs)

| Aa | A | Baa | Ba | B |
|---|---|---|---|---|
| Terasen Gas (Vancouver Island) Inc. | Atlanta Gas Light Company | Berkshire Gas Company | Gas Natural Ban S.A. | Camuzzi Gas Pampeana S.A. |
| | Bay State Gas Company | Boston Gas Company | | Metrogas S.A. |
| | Brooklyn Union Gas Company, The | Cascade Natural Gas Corp. | | |
| | Indiana Gas Company, Inc. | Cia de Gas de São Paulo - COMGAS | | |
| | Michigan Consolidated Gas Company | Colonial Gas Company | | |
| | New Jersey Natural Gas Company | Connecticut Natural Gas Corporation | | |
| | Northwest Natural Gas Company | Laclede Gas Company | | |
| | Piedmont Natural Gas Company, In | North Shore Gas Company | | |
| | Public Service Co. of North Carolina, Inc. | Northern Illinois Gas Company | | |
| | South Jersey Gas Company | Peoples Gas Light and Coke Co. | | |
| | Southern California Gas Company | SEMCO Energy, Inc. | | |
| | Terasen Gas Inc. | Source Gas LLC | | |
| | Wisconsin Gas LLC | Southern Connecticut Gas Company | | |
| | | Southwest Gas Corporation | | |
| | | UGI Utilities, Inc. | | |
| | | UNS Gas | | |
| | | Washington Gas Light Company | | |
| | | Yankee Gas Services Company | | |

## Moody's Related Research

Rating Methodology:

» Regulated Electric and Gas Utilities, August 2009 (118481)

Industry Outlook:

» U.S. Electric Utilities Face Challenges Beyond Near-Term, January 2010 (121717)

Special Comment:

» Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, June 2010 (125664)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

» contacts continued from page 1

**Analyst Contacts:**

NEW YORK 1.212.553.1653

Jim Hempstead 1.212.553.4318
*Senior Vice President*
James.Hempstead@moodys.com

A.J, Sabatelle 1.212.553.4136
*Senior Vice President*
Angelo.Sabatelle@moodys.com

Mihoko Manabe 1.212.553.1942
*Vice President – Senior Credit Officer*
Mihoko.Manabe@moodys.com

Allan McLean 1.416.214.3852
*Vice President – Senior Credit Officer*
Allan.McLean@moodys.com

Kevin Rose 1.212.553.0389
*Vice President – Senior Analyst*
Kevin.Rose@moodys.com

Laura Schumacher 1.212.553.3852
*Vice President – Senior Analyst*
Laura.Schumacher@moodys.com

Scott Solomon 1.212.553.4358
*Vice President – Senior Analyst*
Scott.Solomon@moodys.com

Natividad Martel 1.212.553.4561
*Analyst*
Natividad.Martel@moodys.com

Jim O'Shaughnessy 1.212.553.1607
*Analyst*
Jim.O'Shaughnessy@moodys.com

Wesley (Wes) Smyth 1.212.553.2733
*Vice President – Senior Accounting Specialist*
Wesley.Smythe@moodys.com

HONG KONG 1.852.3551.3077

Jennifer Wong 1.852.3758.1373
*Assistant Vice President–Analyst*
Jennifer.Wong@moodys.com

SAO PAULO 5511.3043.7300

Jose Soares 5511.3043.7339
*Vice President-Senior Analyst*
Jose.Soares@moodys.com

BUENOS AIRES 5411.4816.2332

Daniela Cuan EXT 141
*Vice President-Senior Analyst*
Daniela.Cuan@moodys.com

LONDON 4420.7772.5454

Helen Francis 4420.7772.5422
*Vice President-Senior Credit Officer*
Helen.Francis@moodys.com

TOKYO 81.3.5408.8100

Kenji Okamoto 81.3.5408.4219
*Vice President- Senior Analyst*
Kenji.Okamoto@moodys.com

Report Number: 122304

**Author**
**Michael G. Haggarty**

**Associate Analyst**
**Joseph Vinciguerra**

**Senior Associate**
**John Grause**

**Production Associate**
**Sylviane Grant**



MOODY'S
INVESTORS SERVICE

ond into stock. The
y is that it may be
erest due to the

e of a double-feature
hen, if the com-
may even be ob-
keep the bond until
vertible financing,

proceeds it obtains
called a refunding
oing this only if a
d by the maturing

## lustries

an assessment of the
portant to a com-
g agencies, are
, and Fitch Ratings
lps). Figure 21-1 ex-
und provides brief

n, and rate its
a missed interest or
ven default (how
lt). Each of these
constitute a meas-
t risk are given the
er risks that may af-
affected by interest
f the bonds may be
ve or stagnant the

ade carefully under
the U.S. electric util-
hose companies'
rimary concern, the
l rating agencies
tegy and philosophy,
heir stability, the
r utilities and its



suppliers, the company's capital structure, earnings in relation to interest requirements, regulatory developments in the industry, potential acquisitions, the status of major litigation against the company, and so forth.

All companies are interested in maintaining as high a rating as they can under the circumstances of their operation. Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid. Thus, a company with the highest rating may benefit in two ways: continuous access to capital and less interest to be payable over the life of the bond. At the other end of the scale, a very high credit rating also can imply that the utility is employing its capital inefficiently. As debt is cheaper to service than equity in most cases, it is usually sensible to maintain a balance of some debt funding (to lower financing costs) at the price of a lower credit rating.

The ratings assigned to debt securities are not static, but may be changed by the rating agencies as individual company circumstances change. These agencies conduct continuing evaluations of the risks taken by utility investors, and the ensuing market adjustments of securities pricing reflect those risks.

What might some of those risks be? Energy trading, for one: The years 2000-2003 provided a very vivid demonstration of the risks inherent in the creation of a new trading market, with a highly volatile, illiquid, nonstorable commodity. All parties now accept that to run such a potentially volatile business with a high debt burden (and low credit rating) is unsustainable in the medium term. Thin profit margins, occasional operating losses, and exposure to counterparty risk—the risk that a party to the trading contract might not fulfill its agreed-upon obligations—could crimp a diversified energy company's credit wings. Failures and shortcomings in unregulated (usually energy trading) businesses were the single most common business cause for negative rating action in 2002 and 2003, according to a study by Fitch Ratings published in December 2003.

Rating agencies also typically take a dim view of merger and acquisition activity. History has demonstrated that many merged entities struggle to generate sufficient additional returns to pay for the additional investment needed to execute the merger. Until recently, mergers and acquisitions were the single most common cause of credit rating downgrades, and seldom result in rating upgrades for both acquiring and acquired entities.

Natural gas companies being acquired, however, have seen their ratings rise for three reasons: (1) they usually are rated lower than the acquiring company; (2) the anticipation of savings can result from the merger; and (3) affiliation with a financially strong electric company can lead to a halo effect.

Another factor that weighs heavily on the credit ratings of utilities is the impact of rating action on parent holding companies and affiliates. The rating agencies take different approaches toward rating families of companies—S&P bases its ratings on a consolidated view, which tends to place ratings of affiliates at the same or nearly the same level, while Fitch and Moody's have traditionally assigned ratings that allow for greater separation of regulated utility company ratings from those of their parents and

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

RatingsDirect®

# Assessing U.S. Investor-Owned Utility Regulatory Environments

**Primary Credit Analyst:**
Todd A Shipman, CFA, New York (1) 212-438-7676; todd.shipman@standardandpoors.com

**Secondary Contacts:**
Barbara A Eiseman, New York (1) 212-438-7666; barbara.eiseman@standardandpoors.com
Gabe Grosberg, New York (1) 212-438-6043; gabe.grosberg@standardandpoors.com
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@standardandpoors.com
Kyle M Loughlin, New York (1) 212-438-7804; kyle.loughlin@standardandpoors.com
Dimitri Nikas, New York (1) 212-438-7807; dimitri.nikas@standardandpoors.com
Ana M Olaya-Rotonti, New York (1) 212-438-8668; ana.olaya-rotonti@standardandpoors.com
Matthew L O'Neill, New York (1) 212-438-4295; matthew.oneill@standardandpoors.com

## Table Of Contents

# Assessing U.S. Investor-Owned Utility Regulatory Environments

Regulatory advantage is the most heavily weighted factor in Standard & Poor's Ratings Services' analysis of a regulated utility's business risk profile. The regulatory environment in the jurisdictions in which a utility operates significantly influences credit quality, but it is not the only determinant of a utility's regulatory risk. A utility management's skill in managing regulatory risk can sometimes overcome a difficult regulatory environment. Conversely, companies can experience greater regulatory risk even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. We modify our assessment of regulatory advantage to account for this dynamic in our ratings methodology (for the criteria we use to rate utilities, see "Corporate Methodology," and "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect.)

In this commentary we discuss the specific factors we use in the U.S. to assess the numerous regulatory jurisdictions here. The assessments help us determine the "preliminary regulatory advantage" in our credit analysis of each U.S. investor-owned regulated utility. They also furnish a means to communicate to investors, issuers, and regulators how regulation affects credit quality. The assessments also inform our opinions of a utility's management by highlighting instances where our opinion of a company's regulatory risk diverges from that of its regulatory environment. (For the latest list of our assessments of the regulatory environments in the U.S., see "Utility Regulatory Assessments For U.S. Investor-Owned Utilities," published Jan. 7, 2014.)

We organize the subfactors of regulatory advantage into four categories as follows:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

## A. Regulatory Stability

The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing the principles of transparency, predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early years of the 20th century), and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.

### 1. Durability of regulatory system

An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. Bondholders lend capital to utilities over long periods to fund the development of long-lived assets. A firm understanding of the basic "rules" that will govern how the utility will recover its costs, including servicing its debt and the return of its capital over an extended period, is essential to accurately assess credit risk. Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk.

The length of time a regulatory framework has been in place is the most important factor in this area. We view jurisdictions as strongest when there have been no major changes or where the approach has been consistent for a long time and is not prone to further changes. We assess jurisdictions where there's been a major, fundamental change in the regulatory paradigm that seems to be working well, but it's too soon to confidently predict that there won't be an effort to revisit the changes, as the next strongest. We assess a jurisdiction lower if it is in the midst of a transition to a new regulatory approach and there is no sign that it will harm credit quality, or there is ongoing exposure to a risk of disruptive change. The assessment will be lower if the transition is attracting negative political attention. The weakest jurisdictions are those that frequently alter the basic regulatory approach. We adjust the assessment downward if the development of the framework was contentious due to policy disputes or legal actions, indicating that the political consensus regarding utility regulation is fragile. We will adjust assessments proactively if changes to the framework are under consideration.

Jurisdictions in many regions and industries permit competitive markets to prevail for some important functions of the delivery of utility services, notably wholesale markets for electricity and retail markets for electric or gas service. In others, vertical integration is the norm. We consider jurisdictions to be weaker if market forces directly influence major cost items that could otherwise be controlled through cost-based regulation. We assess jurisdictions with volatile markets and more significant costs as weaker. The risk inherent in the market-based model is straightforward: Utility rates are more volatile when influenced by markets rather than fully embedded costs, and regulators are apt to resist full and timely recovery when market price changes are abrupt and substantial (and perhaps misunderstood). We reserve the weakest assessments for jurisdictions that are in the midst of deregulating important parts of the utility framework. The uncertainty of the timing of reaching the end state--and what the end result will be--is a negative factor from a credit perspective. Utilities are also prone to financial stress when the transition to competition causes potential "rate shock" that regulators could resist.

### 2. Transparency of regulatory framework and attitude toward credit quality

We believe regulation works best when it is rule-based. Bondholder interests are better protected by the presence of and adherence to a pre-set code of rules and procedures that we can look to when assessing risk. Risk is lower when the rules are more transparent and when they take into account utilities' financial integrity. Jurisdictions that require regulators to protect the financial soundness of utilities and have transparent policies and procedures earn the best assessments. We assign lower assessments on jurisdictions where policies and procedures support financial integrity but where inconsistency can selectively arise. We assess a jurisdiction even lower when transparency merely exists. Weak assessments result when any of these credit factors are absent, or if the regulator's record on following precedent is poor.

## B. Tariff-Setting Procedures

Our analysis of rate decisions is part of our surveillance on each U.S. utility. We focus on the jurisdiction's overall approach to setting rates and the process it uses to establish base rates. We examine the practices pertaining to separate tariff provisions for large expenses in the "Financial Stability" part of our analysis. For this part of our assessment, we focus on whether base rates, over time, fairly reflect a utility's cost structure and allow its managers an opportunity to earn a compensatory return that provides bondholders with a financial cushion that supports credit quality. If the process is geared toward an incentive-based system, the analysis is centered on the risks related tothe incentive mechanisms. If the jurisdiction has vertically integrated utilities, we review the resource procurement process and assess its effect on regulatory risk.

### 1. Ability to timely recover costs

We do not weigh authorized returns heavily in our analysis; instead, we focus on actual earned returns. Examples abound of utilities with healthy authorized returns that have no meaningful expectation of earning those returns due to, for example, rate case lag or expense disallowances. Also, the absolute level of financial returns is less important in our analysis than the stability of that return. Nevertheless, higher earned returns translate into better credit measures and a more comfortable equity cushion for bondholders. We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor in our regulatory assessments.

A strongly assessed jurisdiction is one in which all of the utilities it regulates consistently earn above-average returns. We assess jurisdictions lower if only some of them do, and lower still if the earnings records are below average or highly variable from year to year. We deem jurisdictions as weaker when all utilities earn well-below-average returns, and we consider jurisdictions where all utilities consistently earn exceedingly poor returns, including years with negative returns, as weakest.

There is not a separate assessment for "regulatory lag" (i.e., the relationship between approved rates and the age of the costs used to set those rates), since the record of earned returns is largely a reflection of laggardness. However, we adjust our assessments upward if our analysis shows little regulatory lag, indicating that responsibility for a poor or uneven earnings history lies more with management than its regulators. Regulatory lag is more than just the regulators' efficiencies in completing rate cases. We measure the timeliness of rate decisions, the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return.

If a jurisdiction employs incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between base rate reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit-neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over or under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The assessment depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the flexibility of the framework to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.

There is a muted effect on regulatory risk in jurisdictions where incentives are not central but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel adjustment and purchased power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.

We assess a jurisdiction higher if symmetrical incentive mechanisms are used sparingly. A lower assessment indicates that incentives play a larger role in the rate-setting approach but are well-designed to evenly allocate risk. We assign still lower assessments when incentives dominate and are poorly designed. We deem jurisdictions weakest where incentives significantly degrade risk and are part of a comprehensive incentive regime.

The rates of return and capital structures used to generate the revenue requirement in rate proceedings may not be the primary focus of our assessment, but we still note those and other decisions made in the ratemaking process and assess them based on their relationship to U.S. averages. We consider them to be signals from regulators on their attitude toward credit quality. The capital structure in particular is an indication from the regulator as to whether creditworthiness is an important consideration in its deliberations.

### 2. Oversight of resource procurement

When applicable, a resource procurement process that uses objective guidelines to evaluate competing proposals to meet service obligations and keeps the regulator informed and involved in the decisions can, in our view, help to reduce the risk of subsequent disallowances. If the jurisdiction has an Integrated Resource Plan or similar mechanism that includes the participation of many parties and it uses it to definitively establish the need for new generation, it diminishes credit risk further.

We assess a jurisdiction higher if the resource procurement process is competitive, overseen by the regulator, and the results must be validated by the regulator. We assess a jurisdiction as weaker when the process only features some of those elements. We deem jurisdictions with no regulator involvement in the process--other than to later disallow some cost recoveries based on perfect hindsight--as weakest.

When applicable, another key issue that falls under this part of our assessment is the regulatory oversight of large capital projects with long lead times that carry out-sized risks to a utility and its bondholders. Practices such as legislative or regulatory recognition of the need for preapproval of such endeavors, periodic reviews that substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk associated with a utility committing substantial capital well in advance of the rate proceeding that results in the project's placement into the rate base.

We deem jurisdictions stronger when they have an oversight process that includes preapproval by the regulator, ongoing regulatory oversight of a project, and provisions for rolling prudence determinations that improve the chances that all project costs will eventually be reflected in rates. We deem jurisdictions weaker when the process only features some of those elements. We consider jurisdictions even weaker when they don't have any regulatory involvement in the process and have a track record of significant post hoc disallowances of capital costs.

## C. Financial Stability

When we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to bondholders.

### 1. Treatment of significant expenses

When utilities are exposed to major expenses such as fuel and purchased power/gas/water, the presence of separate tariff provisions to facilitate full and contemporaneous recovery is the most prominent factor in this part of our analysis. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of the control of utility management is a key component of a credit-enhancing regulatory jurisdiction. The analysis centers on the special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect our analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part in the regulatory assessment.

We assess a jurisdiction most strongly if all large expense items are recoverable through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. We assign lower assessments if separate mechanisms exist sporadically and lack some of the above features. We view jurisdictions that don't have independent rate mechanisms for large expenses and display a record of significant disallowances as weakest.

### 2. Treatment of capital expenditures

When applicable, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for bondholders. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.

We assess jurisdictions that offer a separate recovery mechanism for all capital spending, a mandated current cash return during construction, and a bonus return for some or all capital projects, as very strong. We deem a jurisdiction as weaker if there is a separate mechanism for only certain kinds of expenditures and the cash return and higher return are subject to the regulator's discretion. We view jurisdictions that don't allow separate recovery or a current return as being lower on the scale. We assess a jurisdiction as weaker still when it doesn't have independent rate mechanisms for capital projects, and we view it as risky when full recovery occurs only after a utility's assets become operational.

### 3. Cash-smoothing mechanisms

We have a more positive view of jurisdictions that make use of innovative regulatory provisions that help to smooth cash flow from period to period. For a jurisdiction that focuses on incentives in its basic approach to ratemaking, through multiyear rate plans or a formula rate plan, we view the availability of "reopeners" (to adjust rates for unexpected events out of the utility's control) as key to this part of our assessment. We view the ability of a utility to petition for a rate increase when unexpected or uncontrollable costs arise in the midst of a long-term rate plan as a critical risk mitigant.

Other examples of risk-dampening regulatory policies include hedging program approvals and weather-related rate practices. If a utility seeks approval of a hedging program to manage exposure to commodity prices, it can reduce risk if there's a clearly stated hedging policy that its regulator has endorsed, and a track record of activity that conforms to the policy that has not been subject to regulatory second-guessing. A well-designed weather-normalization mechanism that efficiently adjusts rates to offset the effect of regular changes in weather will soften earnings and cash flow volatility, to the benefit of bondholders. If applicable, we view a record of regulatory responsiveness to extreme weather events for utilities that are prone to violent or disruptive storms (like hurricanes) as favorable for credit quality.

We assess a jurisdiction very strong if it makes extensive use of extraordinary and credit-supportive rate mechanisms. The next-strongest jurisdictions, in our view, are those that employ innovative mechanisms selectively, or have regulators that are receptive to reopeners where incentives are the main ratemaking method.

## D. Regulatory Independence And Insulation

The role of politics in U.S. utility regulation is often misunderstood. In most jurisdictions, the regulator's function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service but for other constituents as well. In this regard, bondholders should recognize that utility regulation usually harbors political as well as economic risks. Therefore, the potential for political influence on regulation is a determinant in our evaluation of a jurisdiction.

### 1. Political independence of regulator

The primary factor in this part of our assessment is the political independence of regulators. The highest assessment goes to jurisdictions in which the regulator is substantially independent of the political process. We assess jurisdictions somewhat lower when a strong degree of insulation exists, such as when the executive branch of government appoints regulators subject to legislative approval. We consider jurisdictions to be further down the scale when the same voters who pay utility bills directly elect the regulators, but institutional efforts have been made to erect some shield for regulators from transient political concerns. We view jurisdictions that arrange for direct political accountability of regulators that persistently influences regulatory decisions as weakest.

### 2. Record of direct political intervention

The ability of a regulator to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utility managers in managing business and financial risk can be affected by the overall atmosphere that it operates in. In this part of our evaluation, we examine the tone set by politicians, the history of political insulation given to the regulatory body, and the behavior of important constituencies that intervene in utility proceedings. We also track the public visibility of utility issues, because we believe that the likelihood of constructive regulatory behavior increases with the comparative obscurity of utility issues.

We view a jurisdiction as having a lower risk if the regulatory environment is marked by cooperative attitudes and constructive interventions in important matters before the regulator. We assess a jurisdiction lower when the atmosphere is more combative and restricts the regulator's ability to act in the long-term best interests of all parties. We consider jurisdictions as weaker if the regulatory environment is so infused with short-term political influence over regulatory decisions that the regulator is effectively incapable of considering investor interests in its decisions.

## Related Criteria And Research

### Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

### Related Research

- Utility Regulatory Assessments For U.S. Investor-Owned Utilities, Jan. 7, 2014

STANDARD
&POOR'S

RATINGSDIRECT®

November 13, 2006

**Criteria:**

# A Closer Look At Industrials Ratings Methodology

**Corporate & Government Ratings:**
Solomon B Samson, Managing Director/Chief Quality Officer, New York (1) 212-438-7653; sol_samson@standardandpoors.com

## Table Of Contents

**Criteria:**

# A Closer Look At Industrials Ratings Methodology

*(**Editor's Note:** This report is the introduction to a series of articles that takes a detailed look at each of the analytical categories examined in Standard & Poor's rating process for industrials issuers. Click on the link at the end of this article to see the list of other articles included in this series.)*

The rating methodology used by Standard & Poor's focuses on fundamental analysis. Not surprisingly, our conceptual model hasn't changed significantly, but there have been some shifts over time that reflect greater complexity and volatility. Clearly, a rating universe that is dominated by high-yield issuers, compared with a largely investment-grade universe 20 years ago, requires some adjustments. Today's ratings analysis, for instance, puts a lot more emphasis on cash flow and liquidity than in the past.

In addition, our profitability analysis used to be part of our financial risk review, but we now consider it part of our business risk review. The logic of this adjustment was to help give us a better feel for how a company stands up against its peers, which is an important part of our competitive analysis. Using our profitability analysis in this context also helps validate some of our business risk conclusions.

Over the past five or six years, a good deal more attention has been placed on accounting considerations and corporate governance. While management's risk orientation has always been a critical part of our rating decisions, a more complex corporate landscape has required us to drill down deeper into management practices and policies, including a range of issues from ownership to board independence.

While it would be hard to suggest that there have been revolutionary changes to our approach to ratings over the past 10 years, our process has clearly evolved to reflect changes in the marketplace. This will be an ongoing process, and it shouldn't surprise anyone when they look at our methodology 10 years from now and see some additional fine tuning.

## Business Risk/Financial Risk Matrix

Standard & Poor's strives for transparency around its rating process. It should be apparent, however, that the ratings process cannot be entirely reduced to a cookbook approach: Ratings incorporate many subjective judgments, and remain as much an art as a science. Our methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; after them come the financial analysis categories. (Credit ratings often are identified with financial analysis--especially ratios. But it is critical to realize that ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics are rated very differently, to the extent that their business challenges and prospects differ.)

Standard & Poor's developed the matrix in table 1 to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. The table illustrates the relationship of business and financial risk profiles to the issuer credit rating.

**Table 1**

**Business Risk/Financial Risk Matrix**

| | Financial risk profile | | | | |
|---|---|---|---|---|---|
| **Business risk profile** | **Minimal** | **Modest** | **Intermediate** | **Aggressive** | **Highly leveraged** |
| **Excellent** | AAA | AA | A | BBB | BB |
| **Strong** | AA | A | A- | BBB- | BB- |
| **Satisfactory** | A | BBB+ | BBB | BB+ | B+ |
| **Weak** | BBB | BBB- | BB+ | BB- | B |
| **Vulnerable** | BB | B+ | B+ | B | B- |

Table 2 shows the financial risk ratios for industrial companies.

**Table 2**

**Financial Risk Indicative Ratios**

| | **FFO/Total debt (%)** | **Total debt/Total cap (%)** | **Total debt/EBITDA (x)** |
|---|---|---|---|
| Minimal | More than 60 | Less than 25 | Less than 1.5 |
| Modest | 45-60 | 25-35 | 1.5–2.0 |
| Intermediate | 30-45 | 35-45 | 2.0–3.0 |
| Aggressive | 15-30 | 45-55 | 3.0–4.5 |
| Highly leveraged | Less than 15 | More than 55 | More than 4.5 |

FFO--Funds from operations.

The following example illustrates how the tables can be used to better understand our rating conclusions.

### The hypothetical case of Company ABC

Company ABC is deemed to have a 'satisfactory' business risk profile, which is typical of an investment-grade industrial issuer. If its financial risk were 'intermediate', the expected rating outcome should be 'BBB'. ABC's ratios of cash flow to debt of 35% and debt leverage (total debt to EBITDA) of 2.5x are characteristic of 'intermediate' financial risk. In reality, of course, the assessment of financial risk is not so simplistic! It encompasses financial policies and risk tolerance, several perspectives on cash flow adequacy (including free cash flow and the degree of flexibility regarding capital expenditures), and various measures of liquidity (including coverage of short-term maturities).

Company ABC can aspire to being upgraded to the 'A' category by reducing its debt burden to the point that cash flow to debt is more than 60% and debt leverage is only 1.5x. Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. The company can expect to be rated in the 'BB' category if its cash flow to debt ratio is 20% and debt leverage remains at 4.0x, and there is a commitment to keeping its finances at these levels.

### Rating matrix is a guideline, not gospel

The rating matrix is not meant to be precise. There can always be small positives and negatives that would lead to a notch higher or lower than the typical outcome. Moreover, there will always be exceptions--cases that do not fit neatly into this analytical framework. For example, liquidity concerns or litigation could pose overarching risks. Also, the matrix does not address the lowest rungs of the credit spectrum (i.e., the 'CCC' category and lower). These ratings, by definition, reflect some impending crisis or extraordinary vulnerability, and the balanced approach that underlies the matrix framework just does not work well for such situations.

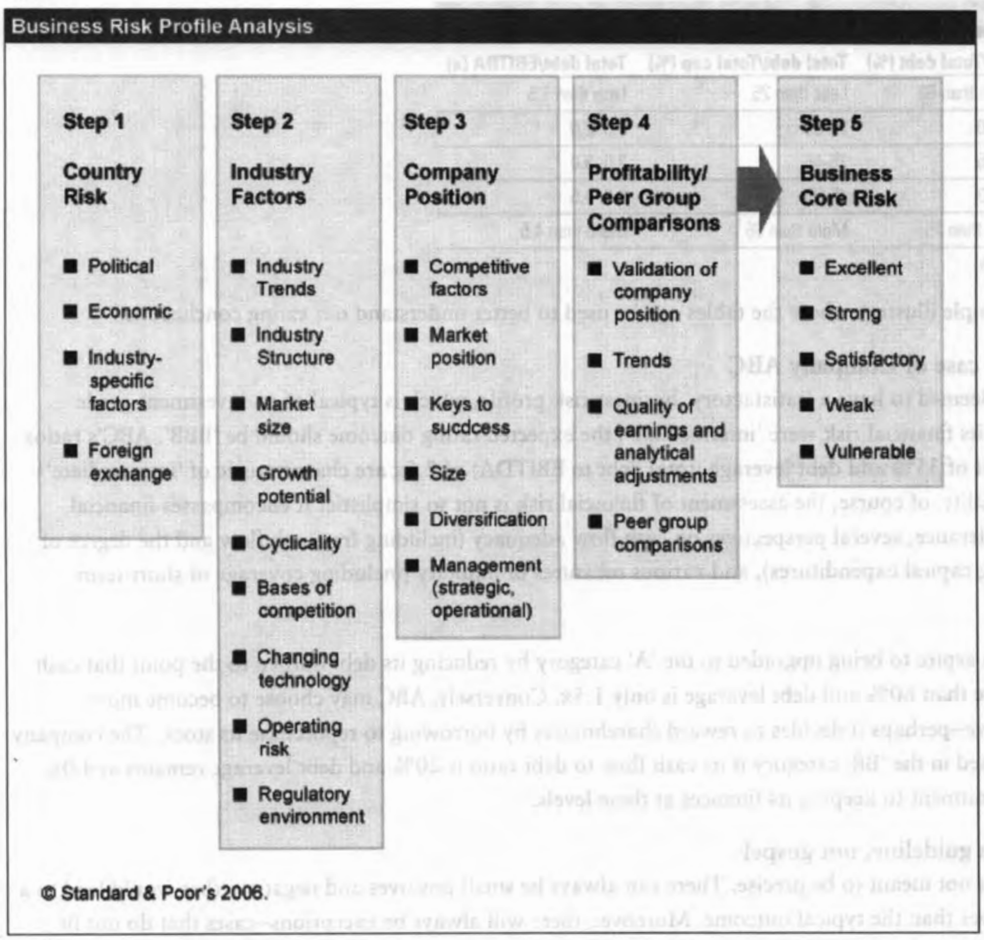
## Corporate Credit Analysis Categories

The categories underlying Standard & Poor's business and financial risk assessments are as follows:

Business Risk

- Country risk
- Industry factors
- Company position
- Profitability/Peer group comparisons

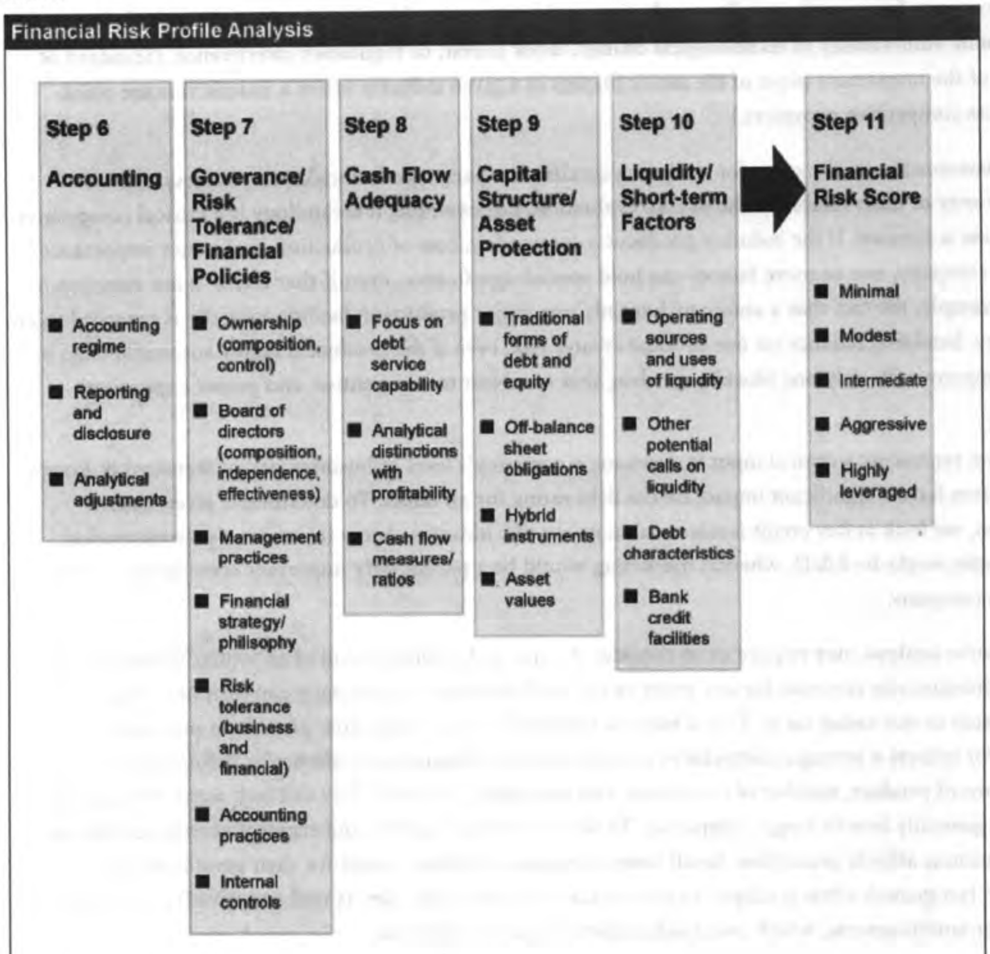
**Chart 1**




Financial Risk

- Accounting
- Governance/Risk tolerance/Financial policies
- Cash flow adequacy
- Capital structure/Asset protection
- Liquidity/Short-term factors

**Chart 2**






## Business risk considerations

### *Country risk.*

Sovereign-related stress can have an overwhelming impact upon company creditworthiness, both direct and indirect. Sovereign credit ratings are suggestive of general risk faced by local entities, but they may not fully capture risk applicable to the private sector. As a result, when rating corporate or infrastructure companies or projects, we look beyond the sovereign ratings to evaluate the specific economic or country risk that may impact the entity's creditworthiness. Such economic or country risk pertains to the impact of government policies upon the obligor's business and financial environment, and a company's ability to insulate itself from these risks.

***Industry factors.***
Each rating analysis begins with an assessment of the given issuer's environment. The degree of operating risk facing a company depends on the dynamics of the industry in which it participates. Our industry analysis focuses on the strength of industry prospects, as well as the competitive factors affecting that industry. The many factors assessed include industry prospects for growth, stability, or decline, and the pattern of business cycles. It is critical, for example, to determine vulnerability to technological change, labor unrest, or regulatory interference. (Standard & Poor's knowledge of the investment plans of the major players in a given industry offers a unique vantage point from which to assess competitive prospects.)

The industry risk assessment sets the stage for analyzing specific company risk factors/keys to success and establishing the priority of these factors in the overall evaluation. For example, if technology is a critical competitive factor, R&D prowess is stressed. If the industry produces a commodity, cost of production is of major importance. For any particular company, one or more factors can hold special significance, even if that factor is not common to the industry. For example, the fact that a company has only one major production facility normally is regarded as an area of vulnerability. Similarly, reliance on one product creates risk, even if the product is highly successful (e.g., a pharmaceutical company with only one blockbuster drug that is subject to competition and patent expiration).

***Company position.***
Competitive position represents a critical input in assessing a company's level of business risk in Standard & Poor's analysis, and can often have a significant impact on the debt rating for an issuer. To determine a given issuer's competitive position, we look at key credit factors within its specific industry. A key factor for a pharmaceutical company, for example, might be R&D, whereas marketing would be a particularly important consideration for a consumer products company.

Part of our competitive analysis may require us to consider the size and diversification of an issuer. While Standard & Poor's has no minimum size criterion for any given rating level, the size of a company can turn out to be significantly correlated to our rating on it. This is because relatively greater scale often provides a measure of diversification and/or reflects a stronger competitive position. Small companies are, almost by definition, more concentrated in terms of product, number of customers, and geography. In effect, they can lack some elements of diversification that generally benefit larger companies. To the extent that markets and regional economies change, a broader scope of business affords protection. Small companies are sometimes touted for their greater growth potential. However, fast growth often is subject to poor execution (even if the idea is well conceived) and can tempt a company into over-ambitiousness, which could subsequently lead to added risk.

***Management evaluation.***
Although management evaluation is considered as part of our company position analysis in our business risk profile analysis chart, we have broken it out as a separate topic of discussion for this series of reports on ratings methodology due to management's obvious importance to an issuer's overall health and creditworthiness. Management is assessed for its role in determining operational success and also for its risk tolerance. The first aspect is incorporated in the business risk analysis; the second is weighed as a financial policy factor. Subjective judgments help determine each aspect of management evaluation. Opinions formed during the meetings with senior management are as important as management's track record. While a track record may seem to offer a more objective basis for evaluation, it often is difficult to determine how results should be attributed to management's

skills. Plans and policies are judged for their realism. How they are implemented determines the view of management consistency and credibility. Stated policies often are not followed, and a rating may reflect skepticism until management has established credibility. Credibility can become a critical issue when a company is faced with stress or restructuring, and the analyst must decide whether to rely on management to carry out plans for restoring creditworthiness.

***Profitability/Peer group comparisons.***

Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Not surprisingly, comparing peer companies on key profit metrics is a useful tool in establishing a firm's position in the food chain. Moreover, conclusions about profitability also serve as a good sanity check on our assessment of business risk.

## Financial risk considerations

Having evaluated the issuer's competitive position and operating environment, the analysis proceeds to several financial categories. To reiterate, the company's business risk profile determines the level of financial risk appropriate for any rating category. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios. Profitability benchmarks vary greatly by industry, and several analytical adjustments typically are required to calculate ratios for an individual company. Cross-border comparisons require additional care, given the differences in accounting conventions and local financial systems.

***Accounting characteristics and information risk.***

Financial statements (and related disclosures) serve as our primary source of information regarding the financial condition and financial performance of industrial and utility companies. The analysis of financial statements begins with a review of accounting characteristics. The purpose is to determine whether ratios and statistics derived from the statements can be used appropriately to measure a company's performance and position relative to both its direct peer group and the larger universe of corporate issuers. The rating process is, in part, one of comparisons, so it is important to have a common frame of reference. Analytical adjustments are made to better portray reality and to level the differences among companies. Although it is rarely possible to completely recast a company's financial statements, it is important to at least have some notion of the extent to which different financial measures are overstated or understated. Apart from their importance to the quantitative aspects of the analysis, conclusions regarding accounting characteristics and financial transparency can also influence qualitative aspects of the analysis, such as the assessment of management.

***Financial policy.***

Standard & Poor's attaches great importance to management's philosophies and policies involving financial risk. A surprising number of companies have not given this question serious thought, much less reached strong conclusions. For many others, debt leverage (calculated without any adjustment to reported figures) is the only focal point of such policy considerations. More sophisticated business managers have thoughtful policies that recognize cash flow parameters and the interplay between business and financial risk. Even those companies that have set goals may not have the wherewithal, discipline, or management commitment to achieve these objectives. Leverage goals, for example, need to be viewed in the context of an issuer's past record and the financial dynamics affecting the business. In some cases, because it can have the most direct affect on their risk profile, financial policy will be the critical factor in determining a company's rating.

***Cash flow adequacy.***
Interest or principal payments cannot be serviced out of earnings, which is just an accounting concept; payment has to be made with cash. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings.

Cash flow analysis is the single most critical aspect of all credit rating decisions. It takes on added importance for speculative-grade issuers. While companies with investment-grade ratings generally have ready access to external financing to cover temporary cash shortfalls, junk bond issuers lack this degree of flexibility and have fewer alternatives to internally generated cash for servicing debt.

***Capital structure and asset protection.***
A review of an issuer's capital structure represents an important part of Standard & Poor's financial review. This analysis helps us determine how much financial flexibility a firm has and how leveraged it is. Of course, when we look at leverage, our analysis goes beyond reported debt on the balance sheet and includes such items as leases, pension and retiree medical liabilities, guarantees, and contingent liabilities. In addition, a company's asset mix is a critical determinant of the appropriate leverage for a given level of risk. Assets with stable cash flows or market values justify greater use of debt financing than those with clouded marketability. Accordingly, we believe it is critical to analyze each type of business and asset class in its own right. While FASB and IAS now require consolidation of nonhomogenous business units, we analyze each separately.

***Liquidity/short-term factors.***
The previously discussed financial factors and liquidity considerations are combined to arrive at an overall view of financial health. In addition, sundry considerations that do not fit in other categories are examined, including serious legal problems, lack of insurance coverage, or restrictive covenants in loan agreements that place the company at the mercy of its bankers. The potential impact of such contingencies is considered, along with the issuer's contingency plans. Access to various capital markets, affiliations with other entities, and the ability to sell assets are important factors in determining a company's options under stress. Flexibility can be jeopardized when an issuer is overly reliant on bank borrowings or commercial paper. Reliance on commercial paper without adequate backup facilities is a big negative. An unusually short maturity schedule for long-term debt and limited-life preferred stock also is a negative. As going concerns, companies should not be expected to repay debt by liquidating operations. Clearly, there is little benefit in selling natural resource properties or manufacturing facilities if they must be replaced in a few years. Nonetheless, the ability to generate cash through asset disposals enhances a company's financial flexibility.

(Each of the articles in our ratings methodology series examines one or more of the aforementioned business and financial risk categories in greater detail, including examples from actual rating situations.)

Click on this link to see other articles included in "Special Report: A Closer Look At Industrial Ratings Methodology."

Click this link for Special Report Archive

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

# RatingsDirect®

Criteria | Corporates | General:

# Corporate Methodology

**Global Criteria Officer, Corporate Ratings:**
Mark Puccia, New York (1) 212-438-7233; mark.puccia@standardandpoors.com

**Chief Credit Officer, Americas:**
Lucy A Collett, New York (1) 212-438-6627; lucy.collett@standardandpoors.com

**European Corporate Ratings Criteria Officer:**
Peter Kernan, London (44) 20-7176-3618; peter.kernan@standardandpoors.com

**Criteria Officer, Asia Pacific:**
Andrew D Palmer, Melbourne (61) 3-9631-2052; andrew.palmer@standardandpoors.com

**Criteria Officer, Corporate Ratings:**
Gregoire Buet, New York (1) 212-438-4122; gregoire.buet@standardandpoors.com

**Primary Credit Analysts:**
Mark S Mettrick, CFA, Toronto (1) 416-507-2584; mark.mettrick@standardandpoors.com
Guy Deslondes, Milan (39) 02-72111-213; guy.deslondes@standardandpoors.com

**Secondary Contacts:**
Michael P Altberg, New York (1) 212-438-3950; michael.altberg@standardandpoors.com
David C Lundberg, CFA, New York (1) 212-438-7551; david.lundberg@standardandpoors.com
Anthony J Flintoff, Melbourne (61) 3-9631-2038; anthony.flintoff@standardandpoors.com
Pablo F Lutereau, Buenos Aires (54) 114-891-2125; pablo.lutereau@standardandpoors.com

## Table Of Contents





1218904 | 300288601

## Table Of Contents (cont.)

Criteria | Corporates | General:

# Corporate Methodology

1. Standard & Poor's Ratings Services is updating its criteria for rating corporate industrial companies and utilities. The criteria organize the analytical process according to a common framework and articulate the steps in developing the stand-alone credit profile (SACP) and issuer credit rating (ICR) for a corporate entity.

2. This article is related to our criteria article "Principles Of Credit Ratings," which we published on Feb. 16, 2011.

## SUMMARY OF THE CRITERIA

3. The criteria describe the methodology we use to determine the SACP and ICR for corporate industrial companies and utilities. Our assessment reflects these companies' business risk profiles, their financial risk profiles, and other factors that may modify the SACP outcome (see "General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating," published Oct. 1, 2010, for the definition of SACP). The criteria provide clarity on how we determine an issuer's SACP and ICR and are more specific in detailing the various factors of the analysis. The criteria also provide clear guidance on how we use these factors as part of determining an issuer's ICR. Standard & Poor's intends for these criteria to provide the market with a framework that clarifies our approach to fundamental analysis of corporate credit risks.

4. The business risk profile comprises the risk and return potential for a company in the markets in which it participates, the competitive climate within those markets (its industry risk), the country risks within those markets, and the competitive advantages and disadvantages the company has within those markets (its competitive position). The business risk profile affects the amount of financial risk that a company can bear at a given SACP level and constitutes the foundation for a company's expected economic success. We combine our assessments of industry risk, country risk, and competitive position to determine the assessment for a corporation's business risk profile.

5. The financial risk profile is the outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to the company's financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

6. We then combine an issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor (see table 3). Additional rating factors can modify the anchor. These are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. Comparable ratings analysis is the last analytical factor under the criteria to determine the final SACP on a company.

7. These criteria are complemented by industry-specific criteria called Key Credit Factors (KCFs). The KCFs describe the industry risk assessments associated with each sector and may identify sector-specific criteria that supersede certain sections of these criteria. As an example, the liquidity criteria state that the relevant KCF article may specify different standards than those stated within the liquidity criteria to evaluate companies that are part of exceptionally stable or

volatile industries. The KCFs may also define sector-specific criteria for one or more of the factors in the analysis. For example, the analysis of a regulated utility's competitive position is different from the methodology to evaluate the competitive position of an industrial company. The regulated utility KCF will describe the criteria we use to evaluate those companies' competitive positions (see "Key Credit Factors For The Regulated Utility Industry," published Nov. 19, 2013).

## SCOPE OF THE CRITERIA

8. This methodology applies to nonfinancial corporate issuer credit ratings globally. Please see "Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt," published Aug. 10, 2009, and "2008 Corporate Criteria: Rating Each Issue," published April 15, 2008, for further information on our methodology for determining issue ratings. This methodology does not apply to the following sectors, based on the unique characteristics of these sectors, which require either a different framework of analysis or substantial modifications to one or more factors of analysis: project finance entities, project developers, transportation equipment leasing, auto rentals, commodities trading, investment holding companies and companies that maximize their returns by buying and selling equity holdings over time, Japanese general trading companies, corporate securitizations, nonprofit and cooperative organizations, master limited partnerships, general partnerships of master limited partnerships, and other entities whose cash flows are primarily derived from partially owned equity holdings.

## IMPACT ON OUTSTANDING RATINGS

9. We expect about 5% of corporate industrial companies and utilities ratings within the scope of the criteria to change. Of that number, we expect approximately 90% to receive a one-notch change, with the majority of the remainder receiving a two-notch change. We expect the ratio of upgrades to downgrades to be around 3:1.

## EFFECTIVE DATE AND TRANSITION

10. These criteria are effective immediately on the date of publication. We intend to complete our review of all affected ratings within the next six months.

## METHODOLOGY

### A. Corporate Ratings Framework

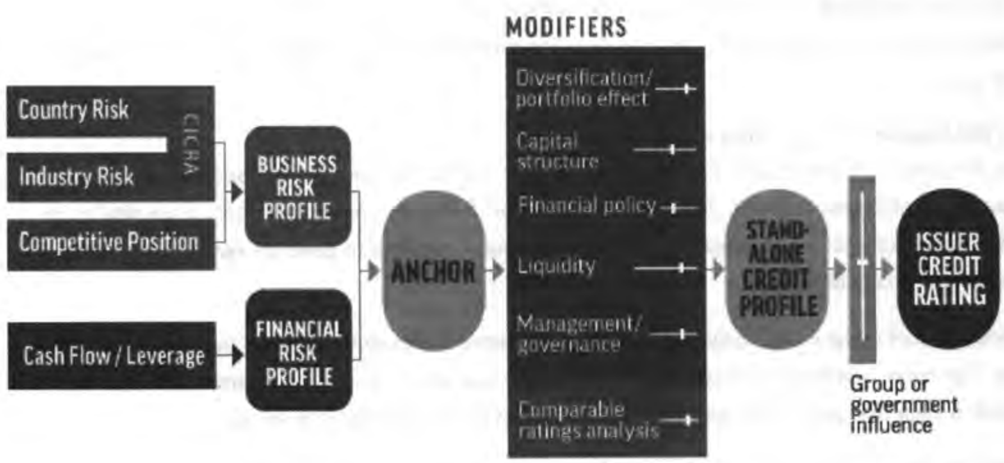
11. The corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several factors so that Standard & Poor's considers all salient issues. First we analyze the company's business risk profile, then evaluate its financial risk profile, then combine those to determine an issuer's anchor. We then analyze six factors that could potentially modify our anchor conclusion.

12. To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.

13. After we determine the anchor, we use additional factors to modify the anchor. These factors are: diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance. The assessment of each factor can raise or lower the anchor by one or more notches--or have no effect. These conclusions take the form of assessments and descriptors for each factor that determine the number of notches to apply to the anchor.

14. The last analytical factor the criteria call for is comparable ratings analysis, which may raise or lower the anchor by one notch based on a holistic view of the company's credit characteristics.

Corporate Criteria Framework




15. The three analytic factors within the business risk profile generally are a blend of qualitative assessments and quantitative information. Qualitative assessments distinguish risk factors, such as a company's competitive advantages, that we use to assess its competitive position. Quantitative information includes, for example, historical cyclicality of revenues and profits that we review when assessing industry risk. It can also include the volatility and level of profitability we consider in order to assess a company's competitive position. The assessments for business risk profile are: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable.

16. In assessing cash flow/leverage to determine the financial risk profile, the analysis focuses on quantitative measures. The assessments for financial risk profile are: 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged.

17. The ICR results from the combination of the SACP and the support framework, which determines the extent of the difference between the SACP and the ICR, if any, for group or government influence. Extraordinary influence is then captured in the ICR. Please see "Group Rating Methodology," published Nov. 19, 2013, and "Rating Government-Related Entities: Methodology And Assumptions," published Dec. 9, 2010, for our methodology on group and government influence.

18. Ongoing support or negative influence from a government (for government-related entities), or from a group, is factored into the SACP (see "SACP criteria"). While such ongoing support/negative influence does not affect the industry or country risk assessment, it can affect any other factor in business or financial risk. For example, such support or negative influence can affect: national industry analysis, other elements of competitive position, financial risk profile, the liquidity assessment, and comparable ratings analysis.

19. The application of these criteria will result in an SACP that could then be constrained by the relevant sovereign rating and transfer and convertibility (T&C) assessment affecting the entity when determining the ICR. In order for the final ICR to be higher than the applicable sovereign rating or T&C assessment, the entity will have to meet the conditions established in "Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions," published Nov. 19, 2013.

### 1. Determining the business risk profile assessment

20. Under the criteria, the combined assessments for country risk, industry risk, and competitive position determine a company's business risk profile assessment. A company's strengths or weaknesses in the marketplace are vital to its credit assessment. These strengths and weaknesses determine an issuer's capacity to generate cash flows in order to service its obligations in a timely fashion.

21. Industry risk, an integral part of the credit analysis, addresses the relative health and stability of the markets in which a company operates. The range of industry risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of industry risk is in section B.

22. Country risk addresses the economic risk, institutional and governance effectiveness risk, financial system risk, and payment culture or rule of law risk in the countries in which a company operates. The range of country risk assessments is: 1, very low risk; 2, low risk; 3, intermediate risk; 4, moderately high risk; 5, high risk; and 6, very high risk. The treatment of country risk is in section C.

23. The evaluation of an enterprise's competitive position identifies entities that are best positioned to take advantage of key industry drivers or to mitigate associated risks more effectively--and achieve a competitive advantage and a stronger business risk profile than that of entities that lack a strong value proposition or are more vulnerable to industry risks. The range of competitive position assessments is: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; and 6, vulnerable. The full treatment of competitive position is in section D.

24. The combined assessment for country risk and industry risk is known as the issuer's Corporate Industry and Country Risk Assessment (CICRA). Table 1 shows how to determine the combined assessment for country risk and industry risk.

**Table 1**

**Determining The CICRA**

| | --Country risk assessment-- | | | | | |
|---|---|---|---|---|---|---|
| **Industry risk assessment** | **1 (very low risk)** | **2 (low risk)** | **3 (intermediate risk)** | **4 (moderately high risk)** | **5 (high risk)** | **6 (very high risk)** |
| 1 (very low risk) | 1 | 1 | 1 | 2 | 4 | 5 |
| 2 (low risk) | 2 | 2 | 2 | 3 | 4 | 5 |
| 3 (intermediate risk) | 3 | 3 | 3 | 3 | 4 | 6 |
| 4 (moderately high risk) | 4 | 4 | 4 | 4 | 5 | 6 |
| 5 (high risk) | 5 | 5 | 5 | 5 | 5 | 6 |
| 6 (very high risk) | 6 | 6 | 6 | 6 | 6 | 6 |

25. The CICRA is combined with a company's competitive position assessment in order to create the issuer's business risk profile assessment. Table 2 shows how we combine these assessments.

**Table 2**

**Determining The Business Risk Profile Assessment**

| | --CICRA-- | | | | | |
|---|---|---|---|---|---|---|
| **Competitive position assessment** | **1** | **2** | **3** | **4** | **5** | **6** |
| 1 (excellent) | 1 | 1 | 1 | 2 | 3* | 5 |
| 2 (strong) | 1 | 2 | 2 | 3 | 4 | 5 |
| 3 (satisfactory) | 2 | 3 | 3 | 3 | 4 | 6 |
| 4 (fair) | 3 | 4 | 4 | 4 | 5 | 6 |
| 5 (weak) | 4 | 5 | 5 | 5 | 5 | 6 |
| 6 (vulnerable) | 5 | 6 | 6 | 6 | 6 | 6 |

*See paragraph 26.

26. A small number of companies with a CICRA of 5 may be assigned a business risk profile assessment of 2 if all of the following conditions are met:

- The company's competitive position assessment is 1.
- The company's country risk assessment is no riskier than 3.
- The company produces significantly better-than-average industry profitability, as measured by the level and volatility of profits.
- The company's competitive position within its sector transcends its industry risks due to unique competitive advantages with its customers, strong operating efficiencies not enjoyed by the large majority of the industry, or scale/scope/diversity advantages that are well beyond the large majority of the industry.

27. For issuers with multiple business lines, the business risk profile assessment is based on our assessment of each of the factors--country risk, industry risk, and competitive position--as follows:

- Country risk: We use the weighted average of the country risk assessments for the company across all business lines that generate more than 5% of sales or where more than 5% of fixed assets are located.

- Industry risk: We use the weighted average of the industry risk assessments for all business lines representing more than 20% of the company's forecasted earnings, revenues or fixed assets, or other appropriate financial measures if earnings, revenue, or fixed assets do not accurately reflect the exposure to an industry.
- Competitive position: We assess all business lines identified above for the components competitive advantage, scope/scale/diversity, and operating efficiency (see section D). They are then blended using a weighted average of revenues, earnings, or assets to form the preliminary competitive position assessment. The level of profitability and volatility of profitability are then assessed based on the consolidated financials for the enterprise. The preliminary competitive position assessment is then blended with the profitability assessment, as per section D.5, to assess competitive position for the enterprise.

### 2. Determining the financial risk profile assessment

28. Under the criteria, cash flow/leverage analysis is the foundation for assessing a company's financial risk profile. The range of assessments for a company's cash flow/leverage is 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; and 6, highly leveraged. The full treatment of cash flow/leverage analysis is the subject of section E.

### 3. Merger of financial risk profile and business risk profile assessments

29. An issuer's business risk profile assessment and its financial risk profile assessment are combined to determine its anchor (see table 3). If we view an issuer's capital structure as unsustainable or if its obligations are currently vulnerable to nonpayment, and if the obligor is dependent upon favorable business, financial, and economic conditions to meet its commitments on its obligations, then we will determine the issuer's SACP using "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012. If the issuer meets the conditions for assigning 'CCC+', 'CCC', 'CCC-', and 'CC' ratings, we will not apply Table 3.

**Table 3**

**Combining The Business And Financial Risk Profiles To Determine The Anchor**

| | --Financial risk profile-- | | | | | |
|---|---|---|---|---|---|---|
| **Business risk profile** | **1 (minimal)** | **2 (modest)** | **3 (intermediate)** | **4 (significant)** | **5 (aggressive)** | **6 (highly leveraged)** |
| 1 (excellent) | aaa/aa+ | aa | a+/a | a- | bbb | bbb-/bb+ |
| 2 (strong) | aa/aa- | a+/a | a-/bbb+ | bbb | bb+ | bb |
| 3 (satisfactory) | a/a- | bbb+ | bbb/bbb- | bbb-/bb+ | bb | b+ |
| 4 (fair) | bbb/bbb- | bbb- | bb+ | bb | bb- | b |
| 5 (weak) | bb+ | bb+ | bb | bb- | b+ | b/b- |
| 6 (vulnerable) | bb- | bb- | bb-/b+ | b+ | b | b- |

30. When two anchor outcomes are listed for a given combination of business risk profile assessment and financial risk profile assessment, an issuer's anchor is determined as follows:

- When a company's financial risk profile is 4 or stronger (meaning, 1-4), its anchor is based on the comparative strength of its business risk profile. We consider our assessment of the business risk profile for corporate issuers to be points along a possible range. Consequently, each of these assessments that ultimately generate the business risk profile for a specific issuer can be at the upper or lower end of such a range. Issuers with stronger business risk profiles for the range of anchor outcomes will be assigned the higher anchor. Those with a weaker business risk profile for the range of anchor outcomes will be assigned the lower anchor.
- When a company's financial risk profile is 5 or 6, its anchor is based on the comparative strength of its financial risk

profile. Issuers with stronger cash flow/leverage ratios for the range of anchor outcomes will be assigned the higher anchor. Issuers with weaker cash flow/leverage ratios for the range of anchor outcomes will be assigned the lower anchor. For example, a company with a business risk profile of (1) excellent and a financial risk profile of (6) highly leveraged would generally be assigned an anchor of 'bb+' if its ratio of debt to EBITDA was 8x or greater and there were no offsetting factors to such a high level of leverage.

## 4. Building on the anchor

31. The analysis of diversification/portfolio effect, capital structure, financial policy, liquidity, and management and governance may raise or lower a company's anchor. The assessment of each modifier can raise or lower the anchor by one or more notches--or have no effect in some cases (see tables 4 and 5). We express these conclusions using specific assessments and descriptors that determine the number of notches to apply to the anchor. However, this notching in aggregate can't lower an issuer's anchor below 'b-' (see "Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings," published Oct. 1, 2012, for the methodology we use to assign 'CCC' and 'CC' category SACPs and ICRs to issuers).

32. The analysis of the modifier diversification/portfolio effect identifies the benefits of diversification across business lines. The diversification/portfolio effect assessments are 1, significant diversification; 2, moderate diversification; and 3, neutral. The impact of this factor on an issuer's anchor is based on the company's business risk profile assessment and is described in Table 4. Multiple earnings streams (which are evaluated within a firm's business risk profile) that are less-than-perfectly correlated reduce the risk of default of an issuer (see Appendix D). We determine the impact of this factor based on the business risk profile assessment because the benefits of diversification are significantly reduced with poor business prospects. The full treatment of diversification/portfolio effect analysis is the subject of section F.

**Table 4**

**Modifier Step 1: Impact Of Diversification/Portfolio Effect On The Anchor**

| | --Business risk profile assessment-- | | | | | |
|---|---|---|---|---|---|---|
| **Diversification/portfolio effect** | **1 (excellent)** | **2 (strong)** | **3 (satisfactory)** | **4 (fair)** | **5 (weak)** | **6 (vulnerable)** |
| 1 (significant diversification) | +2 notches | +2 notches | +2 notches | +1 notch | +1 notch | 0 notches |
| 2 (moderate diversification) | +1 notch | +1 notch | +1 notch | +1 notch | 0 notches | 0 notches |
| 3 (neutral) | 0 notches | 0 notches | 0 notches | 0 notches | 0 notches | 0 notches |

33. After we adjust for the diversification/portfolio effect, we determine the impact of the other modifiers: capital structure, financial policy, liquidity, and management and governance. We apply these four modifiers in the order listed in Table 5. As we go down the list, a modifier may (or may not) change the anchor to a new range (one of the ranges in the four right-hand columns in the table). We'll choose the appropriate value from the new range, or column, to determine the next modifier's effect on the anchor. And so on, until we get to the last modifier on the list—management and governance. For example, let's assume that the anchor, after adjustment for diversification/portfolio effect but before adjusting for the other modifiers, is 'a'. If the capital structure assessment is very negative, the indicated anchor drops two notches, to 'bbb+'. So, to determine the impact of the next modifier—financial policy—we go to the column 'bbb+ to bbb-' and find the appropriate assessment—in this theoretical example, positive. Applying that assessment moves the anchor up one notch, to the 'a- and higher' category. In our example, liquidity is strong, so the impact is zero notches and the anchor remains unchanged. Management and governance is satisfactory, and thus the anchor remains 'a-' (see chart following table 5).

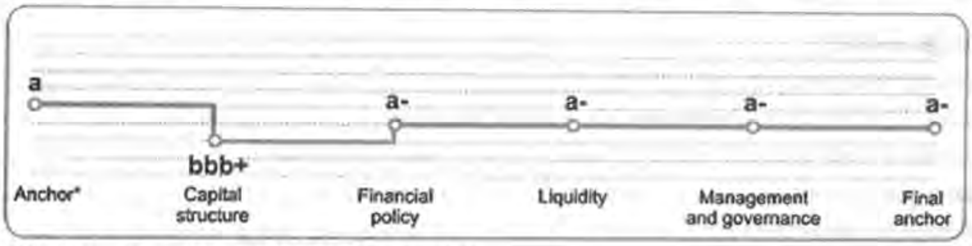
**Table 5**

**Modifier Step 2: Impact Of Remaining Modifier Factors On The Anchor**

| | --Anchor range-- | | | |
|---|---|---|---|---|
| | **'a-' and higher** | **'bbb+' to 'bbb-'** | **'bb+' to 'bb-'** | **'b+' and lower** |
| **Factor/Assessment** | | | | |
| **Capital structure (see section G)** | | | | |
| 1 (Very positive) | 2 notches | 2 notches | 2 notches | 2 notches |
| 2 (Positive) | 1 notch | 1 notch | 1 notch | 1 notch |
| 3 (Neutral) | 0 notches | 0 notches | 0 notches | 0 notches |
| 4 (Negative) | -1 notch | -1 notch | -1 notch | -1 notch |
| 5 (Very negative) | -2 or more notches | -2 or more notches | -2 or more notches | -2 notches |
| **Financial policy (FP; see section H)** | | | | |
| 1 (Positive) | +1 notch if M&G is at least satisfactory | +1 notch if M&G is at least satisfactory | +1 notch if liquidity is at least adequate and M&G is at least satisfactory | +1 notch if liquidity is at least adequate and M&G is at least satisfactory |
| 2 (Neutral) | 0 notches | 0 notches | 0 notches | 0 notches |
| 3 (Negative) | -1 to -3 notches(1) | -1 to -3 notches(1) | -1 to -2 notches(1) | -1 notch |
| 4 (FS-4, FS-5, FS-6, FS-6 [minus]) | N/A(2) | N/A(2) | N/A(2) | N/A(2) |
| **Liquidity (see section I)** | | | | |
| 1 (Exceptional) | 0 notches | 0 notches | 0 notches | +1 notch if FP is positive, neutral, FS-4, or FS-5 (3) |
| 2 (Strong) | 0 notches | 0 notches | 0 notches | +1 notch if FP is positive, neutral, FS-4, or FS-5 (3) |
| 3 (Adequate) | 0 notches | 0 notches | 0 notches | 0 notches |
| 4 (Less than adequate [4]) | N/A | N/A | -1 notch(5) | 0 notches |
| 5 (Weak) | N/A | N/A | N/A | 'b-' cap on SACP |
| **Management and governance (M&G; see section J)** | | | | |
| 1 (Strong) | 0 notches | 0 notches | 0, +1 notches(6) | 0, +1 notches(6) |
| 2 (Satisfactory) | 0 notches | 0 notches | 0 notches | 0 notches |
| 3 (Fair) | -1 notch | 0 notches | 0 notches | 0 notches |
| 4 (Weak) | -2 or more notches(7) | -2 or more notches(7) | -1 or more notches(7) | -1 or more notches(7) |

(1) Number of notches depends on potential incremental leverage. (2) See "Assessing Financial Policy," section H.2. (3) Additional notch applies only if we expect liquidity to remain exceptional or strong. (4) See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013. SACP is capped at 'bb+.' (5) If issuer SACP is 'bb+' due to cap, there is no further notching. (6) This adjustment is one notch if we have not already captured benefits of strong management and governance in the analysis of the issuer's competitive position. (7) Number of notches depends upon the degree of negative effect to the enterprise's risk profile.

### Example: How Remaining Modifiers Can Change The Anchor




*After adjusting for diversification/portfolio effect. See paragraph 33.

34. Our analysis of a firm's capital structure assesses risks in the firm's capital structure that may not arise in the review of its cash flow/leverage. These risks include the currency risk of debt, debt maturity profile, interest rate risk of debt, and an investments subfactor. We assess a corporate issuer's capital structure on a scale of 1, very positive; 2, positive; 3, neutral; 4, negative; and 5, very negative. The full treatment of capital structure is the subject of section G.

35. Financial policy serves to refine the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage, capital structure, and liquidity analyses. Those assumptions do not always reflect or adequately capture the long-term risks of a firm's financial policy. The financial policy assessment is, therefore, a measure of the degree to which owner/managerial decision-making can affect the predictability of a company's financial risk profile. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)." The full treatment of financial policy analysis is the subject of section H.

36. Our assessment of liquidity focuses on the monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis also assesses the potential for a company to breach covenant tests tied to declines in earnings before interest, taxes, depreciation, and amortization (EBITDA). The methodology incorporates a qualitative analysis that addresses such factors as the ability to absorb high-impact, low-probability events, the nature of bank relationships, the level of standing in credit markets, and the degree of prudence of the company's financial risk management. The liquidity assessments are 1, exceptional; 2, strong; 3, adequate; 4, less than adequate; and 5, weak. An SACP is capped at 'bb+' for issuers whose liquidity is less than adequate and 'b-' for issuers whose liquidity is weak, regardless of the assessment of any modifiers or comparable ratings analysis. (For the complete methodology on assessing corporate issuers' liquidity, see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013.)

37. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the company's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. The range of management and governance assessments is: 1, strong; 2, satisfactory; 3, fair; and 4, weak. Typically, investment-grade anchor outcomes reflect strong or satisfactory management and governance, so there is no incremental benefit. Alternatively, a fair or weak assessment of management and governance can lead to a lower anchor. Also, a strong assessment for management and governance for a weaker entity is viewed as a favorable factor, under the criteria, and can have a

positive impact on the final SACP outcome. For the full treatment of management and governance, see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012.

### 5. Comparable ratings analysis

38. The anchor, after adjusting for the modifiers, could change one notch up or down in order to arrive at an issuer's SACP based on our comparable ratings analysis, which is a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch improvement, a negative assessment leads to a one-notch reduction, and a neutral assessment indicates no change to the anchor. The application of comparable ratings analysis reflects the need to 'fine-tune' ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

## B. Industry Risk

39. The analysis of industry risk addresses the major factors that Standard & Poor's believes affect the risks that entities face in their respective industries. (See "Methodology: Industry Risk," published Nov. 19, 2013.)

## C. Country Risk

40. The analysis of country risk addresses the major factors that Standard & Poor's believes affect the country where entities operate. Country risks, which include economic, institutional and governance effectiveness, financial system, and payment culture/rule of law risks, influence overall credit risks for every rated corporate entity. (See "Country Risk Assessment Methodology And Assumptions," published Nov. 19, 2013.)

### 1. Assessing country risk for corporate issuers

41. The following paragraphs explain how the criteria determine the country risk assessment for a corporate entity. Once it's determined, we combine the country risk assessment with the issuer's industry risk assessment to calculate the issuer's CICRA (see section A, table 1). The CICRA is one of the factors of the issuer's business risk profile. If an issuer has very low to intermediate exposure to country risk, as represented by a country risk assessment of 1, 2, or 3, country risk is neutral to an issuer's CICRA. But if an issuer has moderately high to very high exposure to country risk, as represented by a country risk assessment of 4, 5, or 6, the issuer's CICRA could be influenced by its country risk assessment.

42. Corporate entities operating within a single country will receive a country risk assessment for that jurisdiction. For entities with exposure to more than one country, the criteria prospectively measure the proportion of exposure to each country based on forecasted EBITDA, revenues, or fixed assets, or other appropriate financial measures if EBITDA, revenue, or fixed assets do not accurately reflect the exposure to that jurisdiction.

43. Arriving at a company's blended country risk assessment involves multiplying its weighted-average exposures for each country by each country's risk assessment and then adding those numbers. For the weighted-average calculation, the criteria consider countries where the company generates more than 5% of its sales or where more than 5% of its fixed assets are located, and all weightings are rounded to the nearest 5% before averaging. We round the assessment to the

nearest integer, so a weighted assessment of 2.2 rounds to 2, and a weighted assessment of 2.6 rounds to 3 (see table 6).

**Table 6**

**Hypothetical Example Of Weighted-Average Country Risk For A Corporate Entity**

| Country | Weighting (% of business*) | Country risk§ | Weighted country risk |
|---|---|---|---|
| Country A | 45 | 1 | 0.45 |
| Country B | 20 | 2 | 0.4 |
| Country C | 15 | 1 | 0.15 |
| Country D | 10 | 4 | 0.4 |
| Country E | 10 | 2 | 0.2 |
| Weighted-average country risk assessment (rounded to the nearest whole number) | -- | -- | 2 |

*Using EBITDA, revenues, fixed assets, or other financial measures as appropriate. §On a scale from 1-6, lowest to highest risk.

44. A weak link approach, which helps us calculate a blended country risk assessment for companies with exposure to more than one country, works as follows: If fixed assets are based in a higher-risk country but products are exported to a lower-risk country, the company's exposure would be to the higher-risk country. Similarly, if fixed assets are based in a lower-risk country but export revenues are generated from a higher-risk country and cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. If a company's supplier is located in a higher-risk country, and its supply needs cannot be easily redirected elsewhere, we measure exposure to the higher-risk country. Conversely, if the supply chain can be re-sourced easily to another country, we would not measure exposure to the higher risk country.

45. Country risk can be mitigated for a company located in a single jurisdiction in the following narrow case. For a company that exports the majority of its products overseas and has no direct exposure to a country's banking system that would affect its funding, debt servicing, liquidity, or ability to transfer payments from or to its key counterparties, we could reduce the country risk assessment by one category (e.g., 5 to 4) to determine the adjusted country risk assessment. This would only apply for countries where we considered the financial system risk subfactor a constraint on the overall country risk assessment for that country. For such a company, other country risks are not mitigated: Economic risk still applies, albeit less of a risk than for a company that sells domestically (potential currency volatility remains a risk for exporters); institutional and governance effectiveness risk still applies (political risk may place assets at risk); and payment culture/rule of law risk still applies (legal risks may place assets and cross-border contracts at risk).

46. Companies will often disclose aggregated information for blocks of countries, rather than disclosing individual country information. If the information we need to estimate exposure for all countries is not available, we use regional risk assessments. Regional risk assessments are calculated as averages of the unadjusted country risk assessments, weighted by gross domestic product of each country in a defined region. The criteria assess regional risk on a 1-6 scale (strongest to weakest). Please see Appendix A, Table 26, which lists the constituent countries of the regions.

47. If an issuer does not disclose its country-level exposure or regional-level exposure, individual country risk exposures or regional exposures will be estimated.

### 2. Adjusting the country risk assessment for diversity

48. We will adjust the country risk assessment for a company that operates in multiple jurisdictions and demonstrates a high degree of diversity of country risk exposures. As a result of this diversification, the company could have less exposure to country risk than the rounded weighted average of its exposures might indicate. Accordingly, the country risk assessment for a corporate entity could be adjusted if an issuer meets the conditions outlined in paragraph 49.

49. The preliminary country risk assessment is raised by one category to reflect diversity if all of the following four conditions are met:

- If the company's head office, as defined in paragraph 51, is located in a country with a risk assessment stronger than the preliminary country risk assessment;
- If no country, with a country risk assessment equal to or weaker than the company's preliminary country risk assessment, represents or is expected to represent more than 20% of revenues, EBITDA, fixed assets, or other appropriate financial measures;
- If the company is primarily funded at the holding level, or through a finance subsidiary in a similar or stronger country risk environment than the holding company, or if any local funding could be very rapidly substituted at the holding level; and
- If the company's industry risk assessment is '4' or stronger.

50. The country risk assessment for companies that have 75% or more exposure to one jurisdiction cannot be improved and will, in most instances, equal the country risk assessment of that jurisdiction. But the country risk assessment for companies that have 75% or more exposure to one jurisdiction can be weakened if the balance of exposure is to higher risk jurisdictions.

51. We consider the location of a corporate head office relevant to overall risk exposure because it influences the perception of a company and its reputation--and can affect the company's access to capital. We determine the location of the head office on the basis of 'de facto' head office operations rather than just considering the jurisdiction of incorporation or stock market listing for public companies. De facto head office operations refers to the country where executive management and centralized high-level corporate activities occur, including strategic planning and capital raising. If such activities occur in different countries, we take the weakest country risk assessment applicable for the countries in which those activities take place.

## D. Competitive Position

52. Competitive position encompasses company-specific factors that can add to, or partly offset, industry risk and country risk--the two other major factors of a company's business risk profile.

53. Competitive position takes into account a company's: 1) competitive advantage, 2) scale, scope, and diversity, 3) operating efficiency, and 4) profitability. A company's strengths and weaknesses on the first three components shape its competitiveness in the marketplace and the sustainability or vulnerability of its revenues and profit. Profitability can either confirm our initial assessment of competitive position or modify it, positively or negatively. A stronger-than-industry-average set of competitive position characteristics will strengthen a company's business risk profile. Conversely, a weaker-than-industry-average set of competitive position characteristics will weaken a

company's business risk profile.

54. These criteria describe how we develop a competitive position assessment. They provide guidance on how we assess each component based on a number of subfactors. The criteria define the weighting rules applied to derive a preliminary competitive position assessment. And they outline how this preliminary assessment can be maintained, raised, or lowered based on a company's profitability. Standard & Poor's competitive position analysis is both qualitative and quantitative.

### 1. The components of competitive position

55. A company's competitive position assessment can be: 1, excellent; 2, strong; 3, satisfactory; 4, fair; 5, weak; or 6, vulnerable.

56. The analysis of competitive position includes a review of:

- Competitive advantage;
- Scale, scope, and diversity;
- Operating efficiency; and
- Profitability.

57. We follow four steps to arrive at the competitive position assessment. First, we separately assess competitive advantage; scale, scope, and diversity; and operating efficiency (excluding any benefits or risks already captured in the issuer's CICRA assessment). Second, we apply weighting factors to these three components to derive a weighted-average assessment that translates into a preliminary competitive position assessment. Third, we assess profitability. Finally, we combine the preliminary competitive position assessment and the profitability assessment to determine the final competitive position assessment. Profitability can confirm, or influence positively or negatively, the competitive position assessment.

58. We assess the relative strength of each of the first three components by reviewing a variety of subfactors (see table 7). When quantitative metrics are relevant and available, we use them to evaluate these subfactors. However, our overall assessment of each component is qualitative. Our evaluation is forward-looking; we use historical data only to the extent that they provide insight into future trends.

59. We evaluate profitability by assessing two subcomponents: level of profitability (measured by historical and projected nominal levels of return on capital, EBITDA margin, and/or sector-specific metrics) and volatility of profitability (measured by historically observed and expected fluctuations in EBITDA, return on capital, EBITDA margin, or sector specific metrics). We assess both subcomponents in the context of the company's industry.

Table 7

**Competitive Position Components And Subfactors**

| Component | Explanation | Subfactors |
|---|---|---|
| 1. Competitive advantage (see Appendix B, section 1) | The strategic positioning and attractiveness to customers of a company's products or services, and the fragility or sustainability of its business model | • Strategy<br>• Differentiation/uniqueness/product positioning/bundling<br>• Brand reputation and marketing<br>• Product and/or service quality<br>• Barriers to entry and customers' switching costs<br>• Technological advantage and capabilities and vulnerability to/ability to drive technological displacement<br>• Asset base characteristics |
| 2. Scale, scope, and diversity (see Appendix B, section 2) | The concentration or diversification of business activities | • Diversity of products or services<br>• Geographic diversity<br>• Volumes, size of markets and revenues, and market share<br>• Maturity of products or services |
| 3. Operating efficiency (see Appendix B, section 3) | The quality and flexibility of a company's asset base and its cost management and structure | • Cost structure<br>• Manufacturing processes<br>• Working capital management<br>• Technology |
| 4. Profitability | | • Level of profitability (historical and projected return on capital, EBITDA margin, and/or sector-relevant measure)<br>• Volatility of profitability |



## 2. Assessing competitive advantage, scale, scope, and diversity, and operating efficiency

60. We assess competitive advantage; scale, scope, and diversity; and operating efficiency as: 1, strong; 2, strong/adequate; 3, adequate; 4, adequate/weak; or 5, weak. Tables 8, 9, and 10 provide guidance for assessing each component.

61. In assessing the components' relative strength, we place significant emphasis on comparative analysis. Peer comparisons provide context for evaluating the subfactors and the resulting component assessment. We review company-specific characteristics in the context of the company's industry, not just its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.) For example, when evaluating an airline, we will benchmark the assessment against peers in the broader transportation-cyclical industry (including the marine and trucking subsectors), and not just against other airlines. Likewise, we will compare a home furnishing manufacturer with other companies in the consumer durables industry, including makers of appliances or leisure products. We might occasionally extend the comparison to other industries if, for instance, a company's business lines cross several industries, or if there are a limited number of rated peers in an industry, subsector, or region.

62. An assessment of strong means that the company's strengths on that component outweigh its weaknesses, and that the combination of relevant subfactors results in lower-than-average business risk in the industry. An assessment of adequate means that the company's strengths and weaknesses with respect to that component are balanced and that the relevant subfactors add up to average business risk in the industry. A weak assessment means that the company's weaknesses on that component override any strengths and that its subfactors, in total, reveal higher-than-average business risk in the industry.

63. Where a component is not clearly strong or adequate, we may assess it as strong/adequate. A component that is not clearly adequate or weak may end up as adequate/weak.

64. Although we review each subfactor, we don't assess each individually--and we seek to understand how they may reinforce or weaken each other. A component's assessment combines the relative strengths and importance of its subfactors. For any company, one or more subfactors can be unusually important--even factors that aren't common in the industry. Industry KCF articles identify subfactors that are consistently more important, or happen not to be relevant, in a given industry.

65. Not all subfactors may be equally important, and a single one's strength or weakness may outweigh all the others. For example, if notwithstanding a track record of successful product launches and its strong brand equity, a company's strategy doesn't appear adaptable, in our view, to changing competitive dynamics in the industry, we will likely not assess its competitive advantage as strong. Similarly, if its revenues came disproportionately from a narrow product line, we might view this as compounding its risk of exposure to a small geographic market and, thus, assess its scale, scope, and diversity component as weak.

66. From time to time companies will, as a result of shifting industry dynamics or strategies, expand or shrink their product or service lineups, alter their cost structures, encounter new competition, or have to adapt to new regulatory environments. In such instances, we will reevaluate all relevant subfactors (and component assessments).

Table 8

**Competitive Advantage Assessment**

| Qualifier | What it means | Guidance |
|---|---|---|
| Strong | • The company has a major competitive advantage due to one or a combination of factors that supports revenue and profit growth, combined with lower-than-average volatility of profits.<br>• There are strong prospects that the company can sustain this advantage over the long term.<br>• This should enable the company to withstand economic downturns and competitive and technological threats better than its competitors can.<br>• Any weaknesses in one or more subfactors are more than offset by strengths in other subfactors that produce sustainable and profitable revenue growth. | • The company's business strategy is highly consistent with, and adaptable to, industry trends and conditions and supports its leadership in the marketplace.<br>• It consistently develops and markets well-differentiated products or services, aligns products with market demand, and enhances the attractiveness or uniqueness of its value proposition through bundling.<br>• Its superior track record of product development, service quality, and customer satisfaction and retention support its ability to maintain or improve its market share.<br>• Its products or services command a clear price premium relative to its competitors' thanks to its brand equity, technological leadership, or quality of service; it is able to sustain this advantage with innovation and effective marketing.<br>• It benefits from barriers to entry from regulation, market characteristics, or intrinsic benefits (such as patents, technology, or customer relationships) that effectively reduce the threat of new competition.<br>• It has demonstrated a commitment and ability to effectively reinvest in its asset base, as evidenced by a continuous pipeline of new products and/or improvement in key capabilities, such as employee retention, customer care, distribution, and supplier relations. These tangible and intangible assets support long term prospects of sustainable and profitable growth. |
| Adequate | • The company has some competitive advantages, but not so large as to create a superior business model or durable benefit compared to its peers'.<br>• It has some but not all drivers of competitiveness. Certain factors support the business' long-term viability and should result in average profitability and average profit volatility during recessions or periods of increased competition. However, these drivers are partially offset by the company's disadvantages or lack of sustainability of other factors. | • The company's strategy is well adapted to marketplace conditions, but it is not necessarily a leader in setting industry trends.<br>• It exhibits neither superior nor subpar abilities with respect to product or service differentiation and positioning.<br>• Its products command no price premium or advantage relative to competing brands as a result of its brand equity or its technological positioning.<br>• It may enjoy some barriers to entry that provide some defense against competitors but don't overpower them. It faces some risk of product/service displacement or substitution longer term.<br>• Its metrics of product or service quality and customer satisfaction or retention are in line with its industry's average. The company could lose customers to competitors if it makes operational missteps.<br>• Its asset profile does not exhibit particularly superior or inferior characteristics compared to other industry participants. These assets generate consistent revenue and profit growth although long-term prospects are subject to some uncertainty. |

| | | |
|---|---|---|
| Weak | • The company has few, if any, competitive advantages and a number of competitive disadvantages.<br>• Because the company lacks many competitive advantages, its long-term prospects are uncertain, and its profit volatility is likely to be higher than average for its industry.<br>• The company is less likely than its competitors to withstand economic, competitive, or technological threats.<br>• Alternatively, the company has weaknesses in one or more subfactors that could keep its profitability below average and its profit volatility above average during economic downturns or periods of increased competition. | • The company's strategy is inconsistent with, or not well adapted to, marketplace trends and conditions.<br>• There is evidence of little innovation, slowness in developing and marketing new products, an inability to raise prices, and/or ineffective bundling.<br>• Its products generally enjoy no price premium relative to competing brands and it often has to sell its products at a lower price than its peers can command.<br>• It has suffered or is at risk of suffering customer defections due to falling quality and because customers perceive its products or services to be less valuable than those of its competitors.<br>• Its revenues and market shares are vulnerable to aggressive pricing by existing or new competitors or to technological displacement risks over the near to medium term.<br>• Its metrics of product or service quality and customer satisfaction or retention are weaker than the industry average.<br>• Its reinvestment in its business is lower than its peers', its ability to retain operational talent is limited, its distribution network is inefficient, and its revenue could stagnate or decline as result. |

Table 9

**Scale, Scope, And Diversity**

| Qualifier | What it means | Guidance |
|---|---|---|
| Strong | • The company's overall scale, scope, and diversity supports stable revenues and profits by rendering it essentially invulnerable to all but the most disruptive combinations of adverse factors, events, or trends.<br>• Its significant advantages in scale, scope, and diversity enable it to withstand economic, regional, competitive, and technological threats better than its competitors can. | • The company's range of products or services is among the most comprehensive in its sector. It derives its revenue and profits from a broader set of products or services than the industry average.<br>• Its products and services enjoy industry-leading market shares relative to other participants in its industry.<br>• It does not rely on a particular customer or small group of customers. If it does, the customer(s) is/are of high credit quality, their demand is highly sustainable, or the company and its customer(s) have significant interdependence.<br>• It does not depend on any particular supplier or related group of suppliers that it could not easily replace. If it does, the supplier(s) is/are of high credit quality, or the company and its supplier(s) have significant interdependence.<br>• It enjoys broader geographic diversity than its peers and doesn't overly depend on a single regional or local market. If it does, the market is local, often for regulatory reasons. The company's production or service centers are diversified across several locations.<br>• It holds a strategic investment that provides positive business diversification. |
| Adequate | • The company's overall scale, scope, and diversity is comparable to its peers'.<br>• Its ability to withstand economic, competitive, or technological threats is comparable to the ability of others within its sector. | • The company has a broad range of products or services compared with its competitors and doesn't depend on a particular product or service for the majority of its revenues and profits.<br>• Its market share is average compared with that of its competitors.<br>• Its dependence on or concentration of key customers is no higher than the industry average, and the loss of a top customer would be unlikely to pose a high risk to its business stability.<br>• It isn't overly dependent on any supplier or regional group of suppliers that it couldn't easily replace.<br>• It doesn't depend excessively on a single local or regional market, and its geographic footprint of production and revenue compares with that of other industry participants. |

| | | |
|---|---|---|
| Weak | • The company's lack of scale, scope, and diversity compromises the stability and sustainability of its revenues and profits.<br>• The company's vulnerability to, or reliance on, various elements of scale, scope, and diversity leaves it less likely than its competitors to withstand economic, competitive, or technological threats. | • The company's product or service lineup is somewhat limited compared to those of its sector peers. The company derives its profits from a narrow group of products or services, and has not achieved significant market share compared with its peers.<br>• Demand for its products or services is lower than for its competitors', and this trend isn't improving.<br>• It relies heavily on a particular customer or small group of customers, and the characteristics of the customer base do not mitigate this risk.<br>• It depends on a particular supplier or group of suppliers, which it would not be able to easily replace without incurring high switching costs.<br>• It depends disproportionately on a single local or regional economy for selling its goods or services, and the company's industry is global.<br>• Key production assets are concentrated by location, and the company has limited ability to quickly replace them without incurring high costs relative to its profits. |



Table 10

**Operating Efficiency Assessment**

| Qualifier | What it means | Guidance |
|---|---|---|
| Strong | • The company maximizes revenues and profits via intelligent use of assets and by minimizing costs and increasing efficiency.<br>• The company's cost structure should enable it to withstand economic downturns better than its peers. | • The company has a lower cost structure than its peers resulting in higher profits or margins even if capacity utilization or demand are well below ideal levels and during down economic and industry cycles.<br>• It has demonstrated its ability to efficiently manage fixed and variable costs in cyclical downturns, and has a history of successful and often ongoing cost reductions programs.<br>• Its capacity utilization is close to optimal at the peak of the industry cycle and outperforms the industry average over the cycle.<br>• It has demonstrated that it can pass along increases in input costs and we expect this will continue.<br>• It has a very high ability to adjust production and labor costs in response to changes in demand without repercussions for product quality, or has demonstrated the ability to operate very profitably in a more costly or less flexible labor environment.<br>• Its suppliers have demonstrated an ability to meet swings in demand without causing bottlenecks or quality issues, and can absorb all but the most severe supply chain disruptions.<br>• It has superior working capital management, as evidenced by a consistently better-than-average "cash conversion cycle" and other working capital metrics, supporting higher cash flow and lower funding costs.<br>• Its investments in technology are likely to increase revenue growth and/or improve its cost structure and operating efficiency. |

| | | |
|---|---|---|
| Adequate | • A combination of cost structure and efficiency should support sustainable profits with average profit volatility relative to the company's peers. Its cost structure is similar to its peers'. | • The company has demonstrated the ability to manage some fixed and most variable costs except during periods of extremely weak demand, and has some history of cutting costs in good and bad times.<br>• Its cost structure permits some profitability even if capacity utilization or customer demand is well below ideal levels. The company can at least break even during most of the industry/demand cycle.<br>• Its cost structure is in line with its peers'. For example, its selling, general, and administrative (SG&A) expense as a percent of revenue is similar to its peers' and is likely to be stable.<br>• It has demonstrated an ability to adjust labor costs in most scenarios without hurting product output and quality, or can operate profitability in a more costly or less flexible labor environment; it has some success passing on input cost increases, although perhaps only partially or with time lag.<br>• Its suppliers have met typical swings in demand without causing widespread bottlenecks or quality issues, and the company has some capacity to withstand limited supply chain disruptions.<br>• It has good working capital management, evidenced by its cash conversion cycle and working capital metrics that are on par with its peers'.<br>• Its investments in technology are likely to help it at least maintain its cost structure and current level of operating efficiency. |
| Weak | • The company's operating efficiency leaves it with lower profitability than its peers' due to lower asset utilization and/or a higher, less flexible cost structure. | • The company's cost structure permits better-than-marginal profitability only if capacity utilization is at the top of the cycle or during periods of strong demand. The company needs solid and sustained industry conditions to generate fair profitability.<br>• It has limited success or capability of managing fixed costs and even most typically variable costs are fixed in the next two to three years.<br>• It has a limited track record of successful cost reductions, such as reducing labor costs in the face of swings in demand, or it has limited ability to pass along increases in input costs.<br>• Its costs are higher than its peers'. For example, the company's SG&A expense as a percent of revenue is above that of its peers, and likely to remain so.<br>• Its suppliers may face bottlenecks or quality issues in the event of modest swings in demand, or have limited technological capabilities. There is evidence that a limited supply chain disruption would make it difficult for suppliers to meet their commitments to the company.<br>• Its working capital management is weak, as evidenced by working capital metrics that are significantly worse than those of its peers, resulting in lower cash flow and higher funding costs.<br>• It lacks investments in technology, which could hurt is revenue growth and/or result in a higher cost structure and less efficient operations relative to its peers'. |

### 3. Determining the preliminary competitive position assessment: Competitive position group profile and category weightings

67. After assessing competitive advantage; scale, scope, and diversity; and operating efficiency, we determine a company's preliminary competitive position assessment by ascribing a specific weight to each component. The weightings depend on the company's Competitive Position Group Profile (CPGP).

68. There are six possible CPGPs: 1) services and product focus, 2) product focus/scale driven, 3) capital or asset focus, 4) commodity focus/cost driven, 5) commodity focus/scale driven, and 6) national industry and utilities (see table 11 for definitions and characteristics).

**Table 11**

**Competitive Position Group Profile (CPGP)**

| | Definition and characteristics | Examples |
|---|---|---|
| Services and product focus | Brands, product quality or technology, and service reputation are typically key differentiating factors for competing in the industry. Capital intensity is typically low to moderate, although supporting the brand often requires ongoing reinvestment in the asset base. | Typically, these are companies in consumer-facing light manufacturing or service industries. Examples include branded drug manufacturers, software companies, and packaged food. |
| Product focus/scale driven | Product and geographic diversity, as well as scale and market position are key differentiating factors. Sophisticated technology and stringent quality controls heighten risk of product concentration. Product preferences or sales relationships are more important than branding or pricing. Cost structure is relatively unimportant. | The sector most applicable is medical device/equipment manufacturers, particularly at the higher end of the technology scale. These companies largely sell through intermediaries, as opposed to directly to the consumer. |
| Capital or asset focus | Sizable capital investments are generally required to sustain market position in the industry. Brand identification is of limited importance, although product and service quality often remain differentiating factors. | Heavy manufacturing industries typically fall into this category. Examples include telecom infrastructure manufacturers and semiconductor makers. |
| Commodity focus/cost driven | Cost position and efficiency of production assets are more important than size, scope, and diversification. Brand identification is of limited importance | Typically, these are companies that manufacture products from natural resources that are used as raw materials by other industries. Examples include forest and paper products companies that harvest timber or produce pulp, packaging paper, or wood products. |
| Commodity focus/scale driven | Pure commodity companies have little product differentiation, and tend to compete on price and availability. Where present, brand recognition or product differences are secondary or of less importance. | Examples range from pure commodity producers and most oil and gas upstream producers, to some producers with modest product or brand differentiation, such as commodity foods. |
| National industries and utilities | Government policy or control, regulation, and taxation and tariff policies significantly affect the competitive dynamics of the industry (see paragraphs 72-73). | An example is a water-utility company in an emerging market. |

69. The nature of competition and key success factors are generally prescribed by industry characteristics, but vary by company. Where service, product quality, or brand equity are important competitive factors, we'll give the competitive advantage component of our overall assessment a higher weighting. Conversely, if the company produces a commodity product, differentiation comes less into play, and we will more heavily weight scale, scope, and diversity as well as operating efficiency (see table 12).

**Table 12**

**Competitive Position Group Profiles (CPGPs) And Category Weightings**

| Component | --(%)-- | | | | | |
|---|---|---|---|---|---|---|
| | **Services and product focus** | **Product focus/scale driven** | **Capital or asset focus** | **Commodity focus/cost driven** | **Commodity focus/scale driven** | **National industries and utilities** |
| 1. Competitive advantage | 45 | 35 | 30 | 15 | 10 | 60 |
| 2. Scale, scope, and diversity | 30 | 50 | 30 | 35 | 55 | 20 |
| 3. Operating efficiency | 25 | 15 | 40 | 50 | 35 | 20 |
| Total | 100 | 100 | 100 | 100 | 100 | 100 |
| Weighted-average assessment* | 1.0-5.0 | 1.0-5.0 | 1.0-5.0 | 1.0-5.0 | 1.0-5.0 | 1.0-5.0 |

*1 (strong), 2 (strong/adequate), 3 (adequate), 4 (adequate/weak), 5 (weak).

70. We place each of the defined industries (see Appendix B, table 27) into one of the six CPGPs (see above and Appendix B, table 27). This is merely a starting point for the analysis, since we recognize that some industries are less homogenous than others, and that company-specific strategies do affect the basis of competition.

71. In fact, the criteria allow for flexibility in selecting a company's group profile (with its category weightings). Reasons for selecting a profile different than the one suggested in the guidance table could include:

- The industry is heterogeneous, meaning that the nature of competition differs from one subsector to the next, and possibly even within subsectors. The KCF article for the industry will identify such circumstances.
- A company's strategy could affect the relative importance of its key factors of competition.

72. For example, the standard CPGP for the telecom and cable industry is services and product focus. While this may be an appropriate group profile for carriers and service providers, an infrastructure provider may be better analyzed under the capital or asset focus group profile. Other examples: In the capital goods industry, a construction equipment rental company may be analyzed under the capital or asset focus group profile, owing to the importance of efficiently managing the capital spending cycle in this segment of the industry, whereas a provider of hardware, software, and services for industrial automation might be analyzed under the services and product focus group profile, if we believe it can achieve differentiation in the marketplace based on product performance, technology innovation, and service.

73. In some industries, the effects of government policy, regulation, government control, and taxation and tariff policies can significantly alter the competitive dynamics, depending on the country in which a company operates. That can alter our assessment of a company's competitive advantage; scale, size, and diversity; or operating efficiency. When industries in given countries have risks that differ materially from those captured in our global industry risk profile and assessment (see "Methodology: Industry Risk," published Nov. 19, 2013, section B), we will weight competitive advantage more heavily to capture the effect, positive or negative, on competitive dynamics. The assessment of competitive advantage; scale, size, and diversity; and operating efficiency will reflect advantages or disadvantages based on these national industry risk factors. Table 13 identifies the circumstances under which national industry risk factors are positive or negative.

Table 13

| National Industry Risk Factors | |
|---|---|
| National industry risk factors are positive | • Government policy including regulation, ownership, and taxation is supportive and has a good track record of mitigating risks to the stability of industry margins.<br>• Any government ownership, tariff, and taxation policy supports growth prospects for revenues and profit generation.<br>• There is very little discernible risk of negative policy, regulatory, ownership, or taxation changes that could threaten business stability. |
| National industry risk factors are negative | • Government policy and regulation has a weak track record of stabilizing margins and reducing industry risks.<br>• Any government ownership, tariff, and taxation policy undermine growth prospects for revenues and profit generation.<br>• There is an increasing risk of negative policy, ownership, and taxation changes that could undermine industry stability. |



74. When national industry risk factors are positive for a company, typically they support revenue growth, profit growth, higher EBITDA margins, and/or lower-than-average volatility of profits. Often, these benefits provide barriers to entry that impede or even bar new market entrants, which should be reflected in the competitive advantage assessment. These benefits may also include risk mitigants that enable a company to withstand economic downturns and competitive and technological threats better in its local markets than its global competitors can. The scale, scope, and diversity assessment might also benefit from these policies if the company is able to withstand economic, regional, competitive, and technological threats better than its global competitors can. Likewise, the company's operating efficiency assessment may improve if, as a result, it is better able than its global competitors to withstand economic downturns, taking into account its cost structure.

75. Conversely, when national industry risk factors are negative for a company, typically they detract from revenue growth and profit growth, shrink EBITDA margins, and/or increase the average volatility of profits. The company may also have less protection against economic downturns and competitive and technological threats within its local markets than its global competitors do. We may also adjust the company's scale, scope, and diversity assessment lower if, as a result of these policies, it is less able to withstand economic, regional, competitive, and technological threats than its global competitors can. Likewise, we may adjust its operating efficiency assessment lower if, as a result of these policies, it is less able to withstand economic downturns, taking into account the company's cost structure.

76. An example of when we might use a national industry risk factor would be for a telecommunications network owner that benefits from a monopoly network position, supported by substantial capital barriers to entry, and as a result is subject to regulated pricing for its services. Accordingly, in contrast to a typical telecommunications company, our analysis of the company's competitive position would focus more heavily on the monopoly nature of its operations, as well as the nature and reliability of the operator's regulatory framework in supporting future revenue and earnings. If we viewed the regulatory framework as being supportive of the group's future earnings stability, and we considered its

monopoly position to be sustainable, we would assess these national industry risk factors as positive in our assessment of the group's competitive position.

77. The weighted average assessment translates into the preliminary competitive position assessment on a scale of 1 to 6, where one is best. Table 14 describes the matrix we use to translate the weighted average assessment of the three components into the preliminary competitive position assessment.

**Table 14**

**Translation Table For Converting Weighted-Average Assessments Into Preliminary Competitive Position Assessments**

| Weighted average assessment range | Preliminary competitive position assessment |
|---|---|
| 1.00 – 1.50 | 1 |
| >1.50 – 2.25 | 2 |
| >2.25 – 3.00 | 3 |
| >3.00 – 3.75 | 4 |
| >3.75 – 4.50 | 5 |
| >4.50 – 5.00 | 6 |

### 4. Assessing profitability

78. We assess profitability on the same scale of 1 to 6 as the competitive position assessment.

79. The profitability assessment consists of two subcomponents: level of profitability and the volatility of profitability, which we assess separately. We use a matrix to combine these into the final profitability assessment.

#### a) Level of profitability

80. The level of profitability is assessed in the context of the company's industry. We most commonly measure profitability using return on capital (ROC) and EBITDA margins, but we may also use sector-specific ratios. Importantly, as with the other components of competitive position, we review profitability in the context of the industry in which the company operates, not just in its narrower subsector. (See list of industries and subsectors in Appendix B, table 27.)

81. We assess level of profitability on a three-point scale: above average, average, and below average. Industry KCF articles may establish numeric guidance, for instance by stating that an ROC above 12% is considered above average, between 8%-12% is average, and below 8% is below average for the industry, or by differentiating between subsectors in the industry. In the absence of numeric guidance, we compare a company against its peers across the industry.

82. We calculate profitability ratios generally based on a five-year average, consisting of two years of historical data, our projections for the current year (incorporating any reported year-to-date results and estimates for the remainder of the year), and the next two financial years. There may be situations where we consider longer or shorter historical results or forecasts, depending on such factors as availability of financials, transformational events (such as mergers or acquisitions [M&A]), cyclical distortion (such as peak or bottom of the cycle metrics that we do not deem fully representative of the company's level of profitability), and we take into account improving or deteriorating trends in profitability ratios in our assessment.

### b) Volatility of profitability

83. We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA, EBITDA margins, or return on capital. The KCF articles provide guidance on which measures are most appropriate for a given industry or set of companies. For each of these measures, we divide the standard error by the average of that measure over the time period in order to ensure better comparability across companies.

84. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly trending data as inherently more volatile. At the same time, we recognize that SER, like any statistical measure, may understate or overstate expected volatility and thus we will make qualitative adjustments where appropriate (see paragraphs 86-90). Furthermore, we only calculate SER when companies have at least seven years of historical annual data and have not significantly changed their line of business during the timeframe, to ensure that the results are meaningful.

85. As with the level of profitability, we evaluate a company's SER in the context of its industry group. For most industries, we establish a six-point scale with 1 capturing the least volatile companies, i.e., those with the lowest SERs, and 6 identifying companies whose profits are most volatile. We have established industry-specific SER parameters using the most recent seven years of data for companies within each sector. We believe that seven years is generally an adequate number of years to capture a business cycle. (See Appendix B, section 4 for industry-specific SER parameters.) For companies whose business segments cross multiple industries, we evaluate the SER in the context of the organization's most dominant industry--if that industry represents at least two-thirds of the organization's EBITDA, sales, or other relevant metric. If the company is a conglomerate and no dominant industry can be identified, we will evaluate its profit volatility in the context of SER guidelines for all nonfinancial companies.

86. In certain circumstances, the SER derived from historical information may understate--or overstate--expected future volatility, and we may adjust the assessment downward or upward. The scope of possible adjustments depends on certain conditions being met as described below.

87. We might adjust the SER-derived volatility assessment to a worse assessment (i.e., to a higher assessment for greater volatility) by up to two categories if the expected level of volatility isn't apparent in historical numbers, and the company either:

- Has a weighted country risk assessment of 4 or worse, which may, notwithstanding past performance, result in a less stable business environment going forward;
- Operates in a subsector of the industry that may be prone to higher technology or regulation changes, or other potential disruptive risks that have not emerged over the seven year period;
- Is of limited size and scope, which will often result in inherently greater vulnerability to external changes; or
- Has pursued material M&A or internal growth projects that obscure the company's underlying performance trend line. As an example, a company may have consummated an acquisition during the trough of the cycle, masking what would otherwise be a significant decline in performance.

88. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

89. Conversely, we may adjust the SER-derived volatility assessment to a better assessment (i.e., to a lower assessment reflecting lower volatility) by up to two categories if we observe that the conditions historically leading to greater volatility have receded and are misrepresentative. This will be the case when:

- The company grew at a moderately faster, albeit more uneven, pace relative to the industry. Since we measure volatility around a linear trend line, a company growing at a constant percentage of moderate increase (relative to the industry) or an uneven pace (e.g., due to "lumpy" capital spending programs) could receive a relatively unfavorable assessment on an unadjusted basis, which would not be reflective of the company's performance in a steady state. (Alternatively, those companies that grow at a significantly higher-than-average industry rate often do so on unsustainable rates of growth or by taking on high-risk strategies. Companies with these high-risk growth strategies would not receive a better assessment and could be adjusted to a worse assessment;)
- The company's geographic, customer, or product diversification has increased in scope as a result of an acquisition or rapid expansion (e.g. large, long-term contracts wins), leading to more stability in future earnings in our view; or
- The company's business model is undergoing material change that we expect will benefit earnings stability, such as a new regulatory framework or major technology shift that is expected to provide a significant competitive hedge and margin protection over time.

90. The choice of one or two categories depends on the degree of likelihood that the related risks will materialize and our view of the likely severity of these risks.

91. If the company either does not have at least seven years of annual data or has materially changed its business lines or undertaken abnormally high levels of M&A during this time period, then we do not use its SER to assess the volatility of profitability. In these cases, we use a proxy to establish the volatility assessment. If there is a peer company that has, and is expected to continue having, very similar profitability volatility characteristics, we use the SER of that peer entity as a proxy.

92. If no such matching peer exists, or one cannot be identified with enough confidence, we perform an assessment of expected volatility based on the following rules:

- An assessment of 3 if we expect the company's profitability, supported by available historical evidence, will exhibit a volatility pattern in line with, or somewhat less volatile than, the industry average.
- An assessment of 2 based on our confidence, supported by available historical evidence, that the company will exhibit lower volatility in profitability metrics than the industry's average. This could be underpinned by some of the factors listed in paragraph 89, whereas those listed in paragraph 87 would typically not apply.
- An assessment of 4 or 5 based on our expectation that profitability metrics will exhibit somewhat higher (4), or meaningfully higher (5) volatility than the industry, supported by available historical evidence, or because of the applicability of possible adjustment factors listed in paragraph 87.
- Assessments of either 1 or 6 are rarely assigned and can only be achieved based on a combination of data evidence and very high confidence tests. For an assessment of 1, we require strong evidence of minimal volatility in profitability metrics compared with the industry, supported by at least five years of historical information, combined with a very high degree of confidence that this will continue in the future, including no country risk, subsector risk or size considerations that could otherwise warrant a worse assessment as per paragraph 87. For an assessment of 6 we require strong evidence of very high volatility in profitability metrics compared with the industry, supported by at least five years of historical information and very high confidence that this will continue in the future.

93. Next, we combine the level of profitability assessment with the volatility assessment to determine the final profitability

assessment using the matrix in Table 15.

**Table 15**

**Profitability Assessment**

| | --Volatility of profitability assessment-- | | | | | |
|---|---|---|---|---|---|---|
| **Level of profitability assessment** | **1** | **2** | **3** | **4** | **5** | **6** |
| Above average | 1 | 1 | 2 | 3 | 4 | 5 |
| Average | 1 | 2 | 3 | 4 | 5 | 6 |
| Below average | 2 | 3 | 4 | 5 | 6 | 6 |

### 5. Combining the preliminary competitive position assessment with profitability

94. The fourth and final step in arriving at a competitive position assessment is to combine the preliminary competitive position assessment with the profitability assessment. We use the combination matrix in Table 16, which shows how the profitability assessment can confirm, strengthen, or weaken (by up to one category) the overall competitive position assessment.

**Table 16**

**Combining The Preliminary Competitive Position Assessment And Profitability Assessment**

| | --Preliminary competitive position assessment-- | | | | | |
|---|---|---|---|---|---|---|
| **Profitability assessment** | **1** | **2** | **3** | **4** | **5** | **6** |
| 1 | 1 | 2 | 2 | 3 | 4 | 5 |
| 2 | 1 | 2 | 3 | 3 | 4 | 5 |
| 3 | 2 | 2 | 3 | 4 | 4 | 5 |
| 4 | 2 | 3 | 3 | 4 | 5 | 5 |
| 5 | 2 | 3 | 4 | 4 | 5 | 6 |
| 6 | 2 | 3 | 4 | 5 | 5 | 6 |

95. We generally expect companies with a strong preliminary competitive position assessment to exhibit strong and less volatile profitability metrics. Conversely, companies with a relatively weaker preliminary competitive position assessment will generally have weaker and/or more volatile profitability metrics. Our analysis of profitability helps substantiate whether management is translating any perceived competitive advantages, diversity benefits, and cost management measures into higher earnings and more stable return on capital and return on sales ratios than the averages for the industry. When profitability differs markedly from what the preliminary/anchor competitive position assessment would otherwise imply, we adjust the competitive position assessment accordingly.

96. Our method of adjustment is biased toward the preliminary competitive position assessment rather than toward the profitability assessment (e.g., a preliminary competitive assessment of 6 and a profitability assessment of 1 will result in a final assessment of 5).

## E. Cash Flow/Leverage

97. The pattern of cash flow generation, current and future, in relation to cash obligations is often the best indicator of a company's financial risk. The criteria assess a variety of credit ratios, predominately cash flow-based, which

complement each other by focusing on the different levels of a company's cash flow waterfall in relation to its obligations (i.e., before and after working capital investment, before and after capital expenditures, before and after dividends), to develop a thorough perspective. Moreover, the criteria identify the ratios that we think are most relevant to measuring a company's credit risk based on its individual characteristics and its business cycle.

98. For the analysis of companies with intermediate or stronger cash flow/leverage assessments (a measure of the relationship between the company's cash flows and its debt obligations as identified in paragraphs 106 and 124), we primarily evaluate cash flows that reflect the considerable flexibility and discretion over outlays that such companies typically possess. For these entities, the starting point in the analysis is cash flows before working capital changes plus capital investments in relation to the size of a company's debt obligations in order to assess the relative ability of a company to repay its debt. These "leverage" or "payback" cash flow ratios are a measure of how much flexibility and capacity the company has to pay its obligations.

99. For entities with significant or weaker cash flow/leverage assessments (as identified in paragraphs 105 and 124), the criteria also call for an evaluation of cash flows in relation to the carrying cost or interest burden of a company's debt. This will help us assess a company's relative and absolute ability to service its debt. These "coverage"- or "debt service"-based cash flow ratios are a measure of a company's ability to pay obligations from cash earnings and the cushion the company possesses through stress periods. These ratios, particularly interest coverage ratios, become more important the further a company is down the credit spectrum.

### 1. Assessing cash flow/leverage

100. Under the criteria, we assess cash flow/leverage as 1, minimal; 2, modest; 3, intermediate; 4, significant; 5, aggressive; or 6, highly leveraged. To arrive at these assessments, the criteria combine the assessments of a variety of credit ratios, predominately cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations. For each ratio, there is an indicative cash flow/leverage assessment that corresponds to a specified range of values in one of three given benchmark tables (see tables 17, 18, and 19). We derive the final cash flow/leverage assessment for a company by determining the relevant core ratios, anchoring a preliminary cash flow assessment based on the relevant core ratios, determining the relevant supplemental ratio(s), adjusting the preliminary cash flow assessment according to the relevant supplemental ratio(s), and, finally, modifying the adjusted cash flow/leverage assessment for any material volatility.

### 2. Core and supplemental ratios

#### a) Core ratios

101. For each company, we calculate two core credit ratios--funds from operations (FFO) to debt and debt to EBITDA--in accordance with Standard & Poor's ratios and adjustments criteria (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013). We compare these payback ratios against benchmarks to derive the preliminary cash flow/leverage assessment for a company. These ratios are also useful in determining the relative ranking of the financial risk of companies.

#### b) Supplemental ratios

102. The criteria also consider one or more supplemental ratios (in addition to the core ratios) to help develop a fuller understanding of a company's financial risk profile and fine-tune our cash flow/leverage analysis. Supplemental ratios

could either confirm or adjust the preliminary cash flow/leverage assessment. The confirmation or adjustment of the preliminary cash flow/leverage assessment will depend on the importance of the supplemental ratios as well as any difference in indicative cash flow/leverage assessment between the core and supplemental ratios as described in section E.3.b.

103. The criteria typically consider five standard supplemental ratios, although the relevant KCF criteria may introduce additional supplemental ratios or focus attention on one or more of the standard supplemental ratios. The standard supplemental ratios include three payback ratios--cash flow from operations (CFO) to debt, free operating cash flow (FOCF) to debt, and discretionary cash flow (DCF) to debt--and two coverage ratios, FFO plus interest to cash interest and EBITDA to interest.

104. The criteria provide guidelines as to the relative importance of certain ratios if a company exhibits characteristics such as high leverage, working capital intensity, capital intensity, or high growth.

105. If the preliminary cash flow/leverage assessment is significant or weaker (see section E.3), then two coverage ratios, FFO plus interest to cash interest and EBITDA to interest, will be given greater importance as supplemental ratios. For the purposes of calculating the coverage ratios, "cash interest" includes only cash interest payments (i.e., interest excludes noncash interest payable on, for example, payment-in-kind [PIK] instruments) and does not include any Standard & Poor's adjusted interest on such items as leases, while "interest" is the income statement figure plus Standard & Poor's adjustments to interest (see "Corporate Methodology: Ratios And Adjustments," published Nov. 19, 2013).

106. If the preliminary cash flow/leverage assessment is intermediate or stronger, the criteria first apply the three standard supplemental ratios of CFO to debt, FOCF to debt, and DCF to debt. When FOCF to debt and DCF to debt indicate a cash flow/leverage assessment that is lower than the other payback-ratio-derived cash flow/leverage assessments, it signals that the company has either larger than average capital spending or other non-operating cash distributions (including dividends). If these differences persist and are consistent with a negative trend in overall ratio levels, which we believe is not temporary, then these supplemental leverage ratios will take on more importance in the analysis.

107. If the supplemental ratios indicate a cash flow/leverage assessment that is different than the preliminary cash flow/leverage assessment, it could suggest an unusual debt service or fixed charge burden, working capital or capital expenditure profile, or unusual financial activity or policies. In such cases, we assess the sustainability or persistence of these differences. For example, if either working capital or capital expenditures are unusually low, leading to better indicated assessments, we examine the sustainability of such lower spending in the context of its impact on the company's longer term competitive position. If there is a deteriorating trend in the company's asset base, we give these supplemental ratios less weight. If either working capital or capital expenditures are unusually high, leading to weaker indicated assessments, we examine the persistence and need for such higher spending. If elevated spending levels are required to maintain a company's competitive position, for example to maintain the company's asset base, we give more weight to these supplemental ratios.

108. For capital-intensive companies, EBITDA and FFO may overstate financial strength, whereas FOCF may be a more accurate reflection of their cash flow in relation to their financial obligations. The criteria generally consider a

capital-intensive company as having ongoing capital spending to sales of greater than 10%, or depreciation to sales of greater than 8%. For these companies, the criteria place more weight on the supplementary ratio of FOCF to debt. Where we place more analytic weight on FOCF to debt, we also seek to estimate the amount of maintenance or full cycle capital required (see Appendix C) under normal conditions (we estimate maintenance or full-cycle capital expenditure required because this is not a reported number). The FOCF figure may be adjusted by adding back estimated discretionary capital expenditures. The adjusted FOCF to debt based on maintenance or full cycle capital expenditures often helps determine how much importance to place on this ratio. If both the FOCF to debt and the adjusted (for estimated discretionary capital spending) FOCF to debt derived assessments are different from the preliminary cash/flow leverage assessment, then these supplemental leverage ratios take on more importance in the analysis.

109. For working-capital-intensive companies, EBITDA and FFO may also overstate financial strength, and CFO may be a more accurate measure of the company's cash flow in relation to its financial risk profile. Under the criteria, if a company has a working capital-to-sales ratio that exceeds 25% or if there are significant seasonal swings in working capital, we generally consider it to be working-capital-intensive. For these companies, the criteria place more emphasis on the supplementary ratio of CFO to debt. Examples of companies that have working-capital-intensive characteristics can be found in the capital goods, metals and mining downstream, or the retail and restaurants industries. The need for working capital in those industries reduces financial flexibility and, therefore, these supplemental leverage ratios take on more importance in the analysis.

110. For all companies, when FOCF to debt or DCF to debt is negative or indicates materially lower cash flow/leverage assessments, the criteria call for an examination of management's capital spending and cash distribution strategies. For high-growth companies, typically the focus is on FFO to debt instead of FOCF to debt because the latter ratio can vary greatly depending on the growth investment the company is undergoing. The criteria generally consider a high-growth company one that exhibits real revenue growth in excess of 8% per year. Real revenue growth excludes price or foreign exchange related growth, under these criteria. In cases where FOCF or DCF is low, there is a greater emphasis on monitoring the sustainability of margins and return on capital and the overall financing mix to assess the likely trend of future debt ratios. In addition, debt service ratio analysis will be important in such situations. For companies with more moderate growth, the focus is typically on FOCF to debt unless the capital spending is short term or is not funded with debt.

111. For companies that have ongoing and well entrenched banking relationships we can reflect these relationships in our cash flow/leverage analysis through the use of the interest coverage ratios as supplemental ratios. These companies generally have historical links and a strong ongoing relationship with their main banks, as well as shareholdings by the main banks, and management influence and interaction between the main banks and the company. Based on their bank relationships, these companies often have lower interest servicing costs than peers, even if the macro economy worsens. In such cases, we generally use the interest coverage ratios as supplemental ratios. This type of banking relationship occurs in Japan, for example, where companies that have the type of bank relationship described in this paragraph tend to have a high socioeconomic influence within their country by way of their revenue size, total debt quantum, number of employees, and the relative importance of the industry.

### c) Time horizon and ratio calculation

112. A company's credit ratios may vary, often materially, over time due to economic, competitive, technological, or investment cycles, the life stage of the company, and corporate or strategic actions. Thus, we evaluate credit ratios on a time series basis with a clear forward-looking bias. The length of the time series is dependent on the relative credit risk of the company and other qualitative factors and the weighting of the time series varies according to transformational events. A transformational event is any event that could cause a material change in a company's financial profile, whether caused by changes to the company's capital base, capital structure, earnings, cash flow profile, or financial policies. Transformational events can include mergers, acquisitions, divestitures, management changes, structural changes to the industry or competitive environment, and/or product development and capital programs. This section provides guidance on the timeframe and weightings the criteria apply to calculate the indicative ratios.

113. The criteria generally consider the company's credit ratios for the previous one to two years, current-year forecast, and the two subsequent forecasted financial years. There may be situations where longer--or even shorter--historical results or forecasts are appropriate, depending on such factors as availability of financials, transformational events, or relevance. For example, a utility company with a long-term capital spending program may lend itself to a longer-term forecast, whereas for a company experiencing a near-term liquidity squeeze even a two-year forecast will have limited value. Alternatively, for most commodities-based companies we emphasize credit ratios based on our forward-looking view of market conditions, which may differ materially from the historical period.

114. Historical patterns in cash flow ratios are informative, particularly in understanding past volatility, capital spending, growth, accounting policies, financial policies, and business trends. Our analysis starts with a review of these historical patterns in order to assess future expected credit quality. Historical patterns can also provide an indication of potential future volatility in ratios, including that which results from seasonality or cyclicality. A history of volatility could result in a more conservative assessment of future cash flow generation if we believe cash flow will continue to be volatile.

115. The forecast ratios are based on an expected base-case scenario developed by Standard & Poor's, incorporating current and near-term economic conditions, industry assumptions, and financial policies. The prospective cyclical and longer-term volatility associated with the industry in which the issuer operates is addressed in the industry risk criteria (see section B) and the longer-term directional influence or event risk of financial policies is addressed in our financial policy criteria (see section H).

116. The criteria generally place greater emphasis on forecasted years than historical years in the time series of credit ratios when calculating the indicative credit ratio. For companies where we have five years of ratios as described in section E.3, generally we calculate the indicative ratio by weighting the previous two years, the current year, and the forecasted two years as 10%, 15%, 25%, 25%, and 25%, respectively.

117. This weighting changes, however, to place even greater emphasis on the current and forecast years when:

- The issuer meets the characteristics described in paragraph 113, and either shorter- or longer-term forecasts are applicable. The weights applied will generally be quite forward weighted, particularly if a company is undergoing a transformational event and there is moderate or better cash flow certainty.
- The issuer is forecast to generate negative cash flow available for debt repayment, which we believe could lead to

deteriorating credit metrics. Forecast negative cash flows could be generated from operating activities as well as capital expenditures, share buybacks, dividends, or acquisitions, as we forecast these uses of cash based on the company's track record, market conditions, or financial policy. The weights applied will generally be 30%, 40%, and 30% for the current and two subsequent years, respectively.

- The issuer is in an industry that is prospectively volatile or that has a high degree of cash flow uncertainty. Industries that are prospectively volatile are industries whose competitive risk and growth assessments are either high risk (5) or very high risk (6) or whose overall industry risk assessments are either high risk (5) or very high risk (6). The weights applied will generally be 50% for the current year and 50% for the first subsequent forecast year.

118. When the indicative ratio(s) is borderline (i.e., less than 10% different from the threshold in relative terms) between two assessment thresholds (as described in section E.3 and tables 17, 18, and 19) and the forecast points to a switch in the ratio between categories during the rating timeframe, we will weigh the forecast even more heavily in order to prospectively capture the trend.

119. For companies undergoing a transformational event, the weighting of the time series could vary significantly.

120. For companies undergoing a transformational event and with significant or weaker cash flow/leverage assessments, we place greater weight on near-term risk factors. That's because overemphasis on longer-term (inherently less predictable) issues could lead to some distortion when assessing the risk level of a speculative-grade company. We generally analyze a company using the arithmetic mean of the credit ratios expected according to our forecasts for the current year (or pro forma current year) and the subsequent financial year. A common example of this is when a private equity firm acquires a company using additional debt leverage, which makes historical financial ratios meaningless. In this scenario, we weight or focus the majority of our analysis on the next one or two years of projected credit measures.

### 3. Determining the cash flow/leverage assessment

#### a) Identifying the benchmark table

121. Tables 17, 18, and 19 provide benchmark ranges for various cash flow ratios we associate with different cash flow/leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow/leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

122. If an industry exhibits low volatility, the threshold levels for the applicable ratios to achieve a given cash flow/leverage assessment are less stringent than those in the medial or standard volatility tables, although the range of the ratios is narrower. Conversely, if an industry exhibits medial or standard levels of volatility, the threshold for the applicable ratios to achieve a given cash flow/leverage assessment are elevated, albeit with a wider range of values.

123. The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA (see section A, table 1). The low volatility table (table 19) will generally apply when a company's CICRA is 1, unless otherwise indicated in a sector's KCF criteria. The medial volatility table (table 18) will be used under certain circumstances for companies with a CICRA of 1 or 2. Those circumstances are described in the respective sectors' KCF criteria. The standard volatility table (table 17) serves as the relevant benchmark table for companies with a CICRA of 2 or worse, and we will always use it for companies with a CICRA of 1 or 2 and whose competitive position is assessed 5 or 6. Although infrequent, we will use the low volatility table when

a company's CICRA is 2 for companies that exhibit or are expected to exhibit low levels of volatility. The choice of volatility tables for companies with a CICRA of 2 is addressed in the respective sector's KCF article.

**Table 17**

**Cash Flow/Leverage Analysis Ratios--Standard Volatility**

| | --Core ratios-- | | --Supplementary coverage ratios-- | | --Supplementary payback ratios-- | | |
|---|---|---|---|---|---|---|---|
| | FFO/debt (%) | Debt/EBITDA (x) | FFO/cash interest(x) | EBITDA/interest (x) | CFO/debt (%) | FOCF/debt (%) | DCF/debt (%) |
| Minimal | 60+ | Less than 1.5 | More than 13 | More than 15 | More than 50 | 40+ | 25+ |
| Modest | 45-60 | 1.5-2 | 9-13 | 10-15 | 35-50 | 25-40 | 15-25 |
| Intermediate | 30-45 | 2-3 | 6-9 | 6-10 | 25-35 | 15-25 | 10-15 |
| Significant | 20-30 | 3-4 | 4-6 | 3-6 | 15-25 | 10-15 | 5-10 |
| Aggressive | 12-20 | 4-5 | 2-4 | 2-3 | 10-15 | 5-10 | 2-5 |
| Highly leveraged | Less than 12 | Greater than 5 | Less than 2 | Less than 2 | Less than 10 | Less than 5 | Less than 2 |

**Table 18**

**Cash Flow/Leverage Analysis Ratios--Medial Volatility**

| | --Core ratios-- | | --Supplementary coverage ratios-- | | --Supplementary payback ratios-- | | |
|---|---|---|---|---|---|---|---|
| | FFO/debt (%) | Debt/EBITDA (x) | FFO/cash interest (x) | EBITDA/interest (x) | CFO/debt (%) | FOCF/debt (%) | DCF/debt (%) |
| Minimal | 50+ | less than 1.75 | 10.5+ | 14+ | 40+ | 30+ | 18+ |
| Modest | 35-50 | 1.75-2.5 | 7.5-10.5 | 9-14 | 27.5-40 | 17.5-30 | 11-18 |
| Intermediate | 23-35 | 2.5-3.5 | 5-7.5 | 5-9 | 18.5-27.5 | 9.5-17.5 | 6.5-11 |
| Significant | 13-23 | 3.5-4.5 | 3-5 | 2.75-5 | 10.5-18.5 | 5-9.5 | 2.5-6.5 |
| Aggressive | 9-13 | 4.5-5.5 | 1.75-3 | 1.75-2.75 | 7-10.5 | 0-5 | (11)-2.5 |
| Highly leveraged | Less than 9 | Greater than 5.5 | Less than 1.75 | Less than 1.75 | Less than 7 | Less than 0 | Less than (11) |

**Table 19**

**Cash Flow/Leverage Analysis Ratios--Low Volatility**

| | --Core ratios-- | | --Supplementary coverage ratios-- | | --Supplementary payback ratios-- | | |
|---|---|---|---|---|---|---|---|
| | FFO/debt (%) | Debt/EBITDA (x) | FFO/cash interest (x) | EBITDA/interest (x) | CFO/debt (%) | FOCF/debt (%) | DCF/debt (%) |
| Minimal | 35+ | Less than 2 | More than 8 | More than 13 | More than 30 | 20+ | 11+ |
| Modest | 23-35 | 2-3 | 5-8 | 7-13 | 20-30 | 10-20 | 7-11 |
| Intermediate | 13-23 | 3-4 | 3-5 | 4-7 | 12-20 | 4-10 | 3-7 |
| Significant | 9-13 | 4-5 | 2-3 | 2.5-4 | 8-12 | 0-4 | 0-3 |
| Aggressive | 6-9 | 5-6 | 1.5-2 | 1.5-2.5 | 5-8 | (10)-0 | (20)-0 |
| Highly leveraged | Less than 6 | Greater than 6 | Less than 1.5 | Less than 1.5 | Less than 5 | Less than (10) | Less than (20) |

## b) Aggregating the credit ratio assessments

124. To determine the final cash flow/leverage assessment, we make these calculations:
1) First, calculate a time series of standard core and supplemental credit ratios, select the relevant benchmark table, and determine the appropriate time weighting of the credit ratios.

- Calculate the two standard core credit ratios and the five standard supplemental credit ratios over a five-year time horizon.
- Consult the relevant industry KCF article (if applicable), which may identify additional supplemental ratio(s). The relevant benchmark table for a given company is based on our assessment of the company's associated industry and country risk volatility, or the CICRA.
- Calculate the appropriate weighted average cash flow/leverage ratios. If the company is undergoing a transformational event, then the core and supplemental ratios will typically be calculated based on Standard & Poor's projections for the current and next one or two financial years.

2) Second, we use the core ratios to determine the preliminary cash flow assessment.

- Compare the core ratios (FFO to debt and debt to EBITDA) to the ratio ranges in the relevant benchmark table.
- If the core ratios result in different cash flow/leverage assessments, we will select the relevant core ratio based on which provides the best indicator of a company's future leverage.

3) Third, we review the supplemental ratio(s).

- Determine the importance of standard or KCF supplemental ratios based on company-specific characteristics, namely, leverage, capital intensity, working capital intensity, growth rate, or industry.

4) Fourth, we calculate the adjusted cash flow/leverage assessment.

- If the cash flow/leverage assessment(s) indicated by the important supplemental ratio(s) differs from the preliminary cash flow/leverage assessment, we might adjust the preliminary cash flow/leverage assessment by one category in the direction of the cash flow/leverage assessment indicated by the supplemental ratio(s) to derive the adjusted cash flow/leverage assessment. We will make this adjustment if, in our view, the supplemental ratio provides the best indicator of a company's future leverage.
- If there is more than one important supplemental ratio and they result in different directional deviations from the preliminary cash flow/leverage assessment, we will select one as the relevant supplemental ratio based on which, in our opinion, provides the best indicator of a company's future leverage. We will then make the adjustment outlined above if the selected supplemental ratio differs from the preliminary cash flow/leverage assessment and the selected supplemental ratio provides the best overall indicator of a company's future leverage.

5) Lastly, we determine the final cash flow/leverage assessment based on the volatility adjustment.

- We classify companies as stable for these cash flow criteria if cash flow/leverage ratios are expected to move up by one category during periods of stress based on their business risk profile. The final cash flow/leverage assessment for these companies will not be modified from the adjusted cash flow/leverage assessment.
- We classify companies as volatile for these cash flow criteria if cash flow/leverage ratios are expected to move one or two categories worse during periods of stress based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 30% from its current level. The final cash flow/leverage assessment for these companies will be modified to one category weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.
- We classify companies as highly volatile for these cash flow criteria if cash flow/leverage ratios are expected to move two or three categories worse during periods of stress, based on their business risk profiles. Typically, this is equivalent to EBITDA declining about 50% from its current level. The final cash flow/leverage assessment for these companies will be modified to two categories weaker than the adjusted cash flow/leverage assessment; the adjustment will be eliminated or reduced to one category if cash flow/leverage ratios, as evaluated, include a moderate to high level of stress already.

125. The volatility adjustment is the mechanism by which we factor a "cushion" of medium-term variance to current financial performance not otherwise captured in either the near-term base-case forecast or the long-term business risk

assessment. We make this adjustment based on the following:

- The expectation of any potential cash flow/leverage ratio movement is both prospective and dependent on the current business or economic conditions.
- Stress scenarios include, but are not limited to, a recessionary economic environment, technology or competitive shifts, loss or renegotiation of major contracts or customers, and key product or input price movements, as typically defined in the company's industry risk profile and competitive position assessment.
- The volatility adjustment is not static and is company specific. At the bottom of an economic cycle or during periods of stressed business conditions, already reflected in the general industry risk or specific competitive risk profile, the prospect of weakening ratios is far less than at the peak of an economic cycle or business conditions.
- The expectation of prospective ratio changes may be formed by observed historical performance over an economic, business, or product cycle by the company or by peers.
- The assessment of which classification to use when evaluating the prospective number of scoring category moves will be guided by how close the current ratios are to the transition point (i.e. "buffer" in the current scoring category) and the corresponding amount of EBITDA movement at each scoring transition.

## F. Diversification/Portfolio Effect

126. Under the criteria, diversification/portfolio effect applies to companies that we regard as conglomerates. They are companies that have multiple core business lines that may be operated as separate legal entities. For the purpose of these criteria, a conglomerate would have at least three business lines, each contributing a material source of earnings and cash flow.

127. The criteria aim to measure how diversification or the portfolio effect could improve the anchor of a company with multiple business lines. This approach helps us determine how the credit strength of a corporate entity with a given mix of business lines could improve based on its diversity. The competitive position factor assesses the benefits of diversity within individual lines of business. This factor also assesses how poorly performing businesses within a conglomerate affect the organization's overall business risk profile.

128. Diversification/portfolio effect could modify the anchor depending on how meaningful we think the diversification is, and on the degree of correlation we find in each business line's sensitivity to economic cycles. This assessment will have either a positive or neutral impact on the anchor. We capture any potential factor that weakens a company's diversification, including poor management, in our management and governance assessment.

129. We define a conglomerate as a diversified company that is involved in several industry sectors. Usually the smallest of at least three distinct business segments/lines would contribute at least 10% of either EBITDA or FOCF and the largest would contribute no more than 50% of EBITDA or FOCF, with the long-term aim of increasing shareholder value by generating cash flow. Industrial conglomerates usually hold a controlling stake in their core businesses, have highly identifiable holdings, are deeply involved in the strategy and management of their operating companies, generally do not frequently roll over or reshuffle their holdings by buying and selling companies, and therefore have high long-term exposure to the operating risks of their subsidiaries.

130. In rating a conglomerate, we first assess management's commitment to maintain the diversified portfolio over a

longer-term horizon. These criteria apply only if the company falls within our definition of a conglomerate.

### 1. Assessing diversification/portfolio effect

131. A conglomerate's diversification/portfolio effect is assessed as 1, significant diversification; 2, moderate diversification; or 3, neutral. An assessment of moderate diversification or significant diversification potentially raises the issuer's anchor. To achieve an assessment of significant diversification, an issuer should have uncorrelated diversified businesses whose breadth is among the most comprehensive of all conglomerates'. This assessment indicates that we expect the conglomerate's earnings volatility to be much lower through an economic cycle than an undiversified company's. To achieve an assessment of moderate diversification, an issuer typically has a range of uncorrelated diversified businesses that provide meaningful benefits of diversification with the expectation of lower earnings volatility through an economic cycle than an undiversified company's.

132. We expect that a conglomerate will also benefit from diversification if its core assets consistently produce positive cash flows over our rating horizon. This supports our assertion that the company diversifies to take advantage of allocating capital among its business lines. To this end, our analysis focuses on a conglomerate's track record of successfully deploying positive discretionary cash flow into new business lines or expanding capital-hungry business lines. We assess companies that we do not expect to achieve these benefits as neutral.

### 2. Components of correlation and how it is incorporated into our analysis

133. We determine the assessment for this factor based on the number of business lines in separate industries (as described in table 27) and the degree of correlation between these business lines as described in table 20. There is no rating uplift for an issuer with a small number of business lines that are highly correlated. By contrast, a larger number of business lines that are not closely correlated provide the maximum rating uplift.

**Table 20**

Assessing Diversification/Portfolio Effect

| | --Number of business lines-- | | |
|---|---|---|---|
| **Degree of correlation of business lines** | **3** | **4** | **5 or more** |
| High | Neutral | Neutral | Neutral |
| Medium | Neutral | Moderately diversified | Moderately diversified |
| Low | Moderately diversified | Significantly diversified | Significantly diversified |

134. The degree of correlation of business lines is high if the business lines operate within the same industry, as defined by the industry designations in Appendix B, table 27. The degree of correlation of business lines is medium if the business lines operate within different industries, but operate within the same geographic region (for further guidance on defining geographic regions, see Appendix A, table 26). An issuer has a low degree of correlation across its business lines if these business lines are both a) in different industries and b) either operate in different regions or operate in multiple regions.

135. If we believe that a conglomerate's various industry exposures fail to provide a partial hedge against the consolidated entity's volatility because they are highly correlated through an economic cycle, then we assess the diversification/portfolio effect as neutral.

## G. Capital Structure

136. Standard & Poor's uses its capital structure criteria to assess risks in a company's capital structure that may not show up in our standard analysis of cash flow/leverage. These risks may exist as a result of maturity date or currency mismatches between a company's sources of financing and its assets or cash flows. These can be compounded by outside risks, such as volatile interest rates or currency exchange rates.

### 1. Assessing capital structure

137. Capital structure is a modifier category, which adjusts the initial anchor for a company after any modification due to diversification/portfolio effect. We assess a number of subfactors to determine the capital structure assessment, which can then raise or lower the initial anchor by one or more notches--or have no effect in some cases. We assess capital structure as 1, very positive; 2, positive; 3, neutral; 4, negative; or 5, very negative. In the large majority of cases, we believe that a firm's capital structure will be assessed as neutral. To assess a company's capital structure, we analyze four subfactors:

- Currency risk associated with debt,
- Debt maturity profile (or schedule),
- Interest rate risk associated with debt, and
- Investments.

138. Any of these subfactors can influence a firm's capital structure assessment, although some carry greater weight than others, based on a tiered approach:

- Tier one risk subfactors: Currency risk of debt and debt maturity profile, and
- Tier two risk subfactor: Interest rate risk of debt.

139. The initial capital structure assessment is based on the first three subfactors (see table 21). We may then adjust the preliminary assessment based on our assessment of the fourth subfactor, investments.

**Table 21**

**Preliminary Capital Structure Assessment**

| Preliminary capital structure assessment | Subfactor assessments |
|---|---|
| Neutral | No tier one subfactor is negative. |
| Negative | One tier one subfactor is negative, and the tier two subfactor is neutral. |
| Very negative | Both tier one subfactors are negative, or one tier one subfactor is negative and the tier two subfactor is negative. |

140. Tier one subfactors carry the greatest risks, in our view, and, thus, could have a significant impact on the capital structure assessment. This is because, in our opinion, these factors have a greater likelihood of affecting credit metrics and potentially causing liquidity and refinancing risk. The tier two subfactor is important in and of itself, but typically less so than the tier one subfactors. In our view, in the majority of cases, the tier two subfactor in isolation has a lower likelihood of leading to liquidity and default risk than do tier one subfactors.

141. The fourth subfactor, investments, as defined in paragraph 153, quantifies the impact of a company's investments on

its overall financial risk profile. Although not directly related to a firm's capital structure decisions, certain investments could provide a degree of asset protection and potential financial flexibility if they are monetized. Thus, the fourth subfactor could modify the preliminary capital structure assessment (see table 22). If the subfactor is assessed as neutral, then the preliminary capital structure assessment will stand. If investments is assessed as positive or very positive, we adjust the preliminary capital structure assessment upward (as per table 22) to arrive at the final assessment.

**Table 22**

**Final Capital Structure Assessment**

| | --Investments subfactor assessment-- | | |
|---|---|---|---|
| **Preliminary capital structure assessment** | **Neutral** | **Positive** | **Very positive** |
| Neutral | Neutral | Positive | Very positive |
| Negative | Negative | Neutral | Positive |
| Very negative | Very negative | Negative | Negative |

## 2. Capital structure analysis: Assessing the subfactors

### a) Subfactor 1: Currency risk of debt

142. Currency risk arises when a company borrows without hedging in a currency other than the currency in which it generates revenues. Such an unhedged position makes the company potentially vulnerable to fluctuations in the exchange rate between the two currencies, in the absence of mitigating factors. We determine the materiality of any mismatch by identifying situations where adverse exchange-rate movements could weaken cash flow and/or leverage ratios. We do not include currency mismatches under the following scenarios:

- The country where a company generates its cash flows has its currency pegged to the currency in which the company has borrowed, or vice versa (or the currency of cash flows has a strong track record and government policy of stability with the currency of borrowings), examples being the Hong Kong dollar which is pegged to the U.S. dollar, and the Chinese renminbi which is managed in a narrow band to the U.S. dollar (and China's foreign currency reserves are mainly in U.S. dollars). Moreover, we expect such a scenario to continue for the foreseeable future;
- A company has the proven ability, through regulation or contract, to pass through changes in debt servicing costs to its customers; or
- A company has a natural hedge, such as where it may sell its product in a foreign currency and has matched its debt in that same currency.

143. We also recognize that even if an entity generates insufficient same-currency cash flow to meet foreign currency-denominated debt obligations, it could have substantial other currency cash flows it can convert to meet these obligations. Therefore, the relative amount of foreign denominated debt as a proportion of total debt is an important factor in our analysis. If foreign denominated debt, excluding fully hedged debt principal, is 15% or less of total debt, we assess the company as neutral on currency risk of debt. If foreign-denominated debt, excluding fully hedged debt principal, is greater than 15% of total debt, and debt to EBITDA is greater than 3.0x, we evaluate currency risks through further analysis.

144. If an entity's foreign-denominated debt in a particular currency represents more than 15% of total debt, and if its debt to EBITDA ratio is greater than 3.0x, we identify whether a currency-specific interest coverage ratio indicates potential

currency risk. The coverage ratio divides forecasted operating cash flow in each currency by interest payments over the coming 12 months for that same currency. It is often easier to ascertain the geographic breakdown of EBITDA as opposed to operating cash flow. So in situations where we don't have sufficient cash flow information, we may calculate an EBITDA to interest expense coverage ratio in the relevant currencies. If neither cash flow nor EBITDA information is disclosed, we estimate the relevant exposures based on available information.

145. In such an instance, our assessment of this subfactor is negative if we believe any appropriate interest coverage ratio will fall below 1.2x over the next 12 months.

### b) Subfactor 2: Debt maturity profile

146. A firm's debt maturity profile shows when its debt needs to be repaid, or refinanced if possible, and helps determine the firm's refinancing risk. Lengthier and more evenly spread out debt maturity schedules reduce refinancing risk, compared with front-ended and compressed ones, since the former give an entity more time to manage business- or financial market-related setbacks.

147. In evaluating debt maturity profiles, we measure the weighted average maturity (WAM) of bank debt and debt securities (including hybrid debt) within a capital structure, and make simplifying assumptions that debt maturing beyond year five matures in year six. WAM = (Maturity1/Total Debt)*tenor1 + (Maturity2/Total Debt)* tenor2 +... (Thereafter/Total Debt)* tenor6

148. In evaluating refinancing risk, we consider risks in addition to those captured under the 12-month to 24-month time-horizons factored in our liquidity criteria (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013). While we recognize that investment-grade companies may have more certain future business prospects and greater access to capital than speculative-grade companies, all else being equal, we view a company with a shorter maturity schedule as having greater refinancing risk compared to a company with a longer one. In all cases, we assess a company's debt maturity profile in conjunction with its liquidity and potential funding availability. Thus, a short-dated maturity schedule alone is not a negative if we believe the company can maintain enough liquidity to pay off debt that comes due in the near term.

149. Our assessment of this subfactor is negative if the WAM is two years or less, and the amount of these near-term maturities is material in relation to the issuer's liquidity so that under our base-case forecast, we believe the company's liquidity assessment will become less than adequate or weak over the next two years due to these maturities. In certain cases, we may assess a debt maturity profile as negative regardless of whether or not the company passes the aforementioned test. We expect such instances to be rare, and will include scenarios where we believed a concentration of debt maturities within a five-year time horizon poses meaningful refinancing risk, either due to the size of the maturities in relation to the company's liquidity sources, the company's leverage profile, its operating trends, lender relationships, and/or credit market standings.

### c) Subfactor 3: Interest rate risk of debt

150. The interest rate risk of debt subfactor analyzes the company's mix of fixed-rate and floating-rate debt. Generally, a higher proportion of fixed-rate debt leads to greater predictability and stability of interest expense and therefore cash flows. The exception would be companies whose operating cash flows are to some degree correlated with interest rate movements--for example, a regulated utility whose revenues are indexed to inflation--given the typical correlation

between nominal interest rates and inflation.

151. The mix of fixed versus floating-rate debt is usually not a significant risk factor for companies with intermediate or better financial profiles, strong profitability, and high interest coverage. In addition, the interest rate environment at a given point in time will play a role in determining the impact of interest rate movements. Our assessment of this subcategory will be negative if a 25% upward shift (e.g., from 2.0% to 2.5%) or a 100 basis-point upward shift (e.g., 2% to 3%) in the base interest rate of the floating rate debt will result in a breach of interest coverage covenants or interest coverage rating thresholds identified in the cash flow/leverage criteria (see section E.3).

152. Many loan agreements for speculative-grade companies contain a clause requiring a percentage of floating-rate debt to be hedged for a period of two to three years to mitigate this risk. However, in many cases the loan matures after the hedge expires, creating a mismatched hedge. We consider only loans with hedges that match the life of the loan to be--effectively--fixed-rate debt.

### d) Subfactor 4: Investments

153. For the purposes of the criteria, investments refer to investments in unconsolidated equity affiliates, other assets where the realizable value isn't currently reflected in the cash flows generated from those assets (e.g. underutilized real-estate property), we do not expect any additional investment or support to be provided to the affiliate, and the investment is not included within Standard & Poor's consolidation scope and so is not incorporated in the company's business and financial risk profile analysis. If equity affiliate companies are consolidated, then the financial benefits and costs of these investments will be captured in our cash flow and leverage analysis. Similarly, where the company's ownership stake does not qualify for consolidation under accounting rules, we may choose to consolidate on a pro rata basis if we believe that the equity affiliates' operating and financing strategy is influenced by the rated entity. If equity investments are strategic and provide the company with a competitive advantage, or benefit a company's scale, scope, and diversity, these factors will be captured in our competitive position criteria and will not be used to assess the subfactor investments as positive. Within the capital structure criteria, we aim to assess nonstrategic financial investments that could provide a degree of asset protection and financial flexibility in the event they are monetized. These investments must be noncore and separable, meaning that a potential divestiture, in our view, has no impact on the company's existing operations.

154. In many instances, the cash flows generated by an equity affiliate, or the proportional share of the associate company's net income, might not accurately reflect the asset's value. This could occur if the equity affiliate is in high growth mode and is currently generating minimal cash flow or net losses. This could also be true of a physical asset, such as real estate. From a valuation standpoint, we recognize the subjective nature of this analysis and the potential for information gaps. As a result, in the absence of a market valuation or a market valuation of comparable companies in the case of minority interests in private entities, we will not ascribe value to these assets.

155. We assess this subfactor as positive or very positive if three key characteristics are met. First, an estimated value can be ascribed to these investments based on the presence of an existing market value for the firm or comparable firms in the same industry. Second, there is strong evidence that the investment can be monetized over an intermediate timeframe--in the case of an equity investment, our opinion of the marketability of the investment would be enhanced by the presence of an existing market value for the firm or comparable firms, as well as our view of market liquidity.

Third, monetization of the investment, assuming proceeds would be used to repay debt, would be material enough to positively move existing cash flow and leverage ratios by at least one category and our view on the company's financial policy, specifically related to financial discipline, supports the assessment that the potential proceeds would be used to pay down debt. This subfactor is assessed as positive if debt repayment from the investment sale has the potential to improve cash flow and leverage ratios by one category. We assess investments as very positive if proceeds upon sale of the investment have the potential to improve cash flow and leverage ratios by two or more categories. If the three characteristics are not met, this subfactor will be assessed as neutral and the preliminary capital structure assessment will stand.

156. We will not assess the investments subfactor as positive or very positive when the anchor is 'b+' or lower unless the three conditions described in paragraph 155 are met, and:

- For issuers with less than adequate or weak liquidity, the company has provided a credible near-term plan to sell the investment.
- For issuers with adequate or better liquidity, we believe that the company, if needed, could sell the investment in a relatively short timeframe.

## H. Financial Policy

157. Financial policy refines the view of a company's risks beyond the conclusions arising from the standard assumptions in the cash flow/leverage assessment (see section E). Those assumptions do not always reflect or entirely capture the short-to-medium term event risks or the longer-term risks stemming from a company's financial policy. To the extent movements in one of these factors cannot be confidently predicted within our forward-looking evaluation, we capture that risk within our evaluation of financial policy. The cash flow/leverage assessment will typically factor in operating and cash flows metrics we observed during the past two years and the trends we expect to see for the coming two years based on operating assumptions and predictable financial policy elements, such as ordinary dividend payments or recurring acquisition spending. However, over that period and, generally, over a longer time horizon, the firm's financial policies can change its financial risk profile based on management's or, if applicable, the company's controlling shareholder's (see Appendix E, paragraphs 254-257) appetite for incremental risk or, conversely, plans to reduce leverage. We assess financial policy as 1) positive, 2) neutral, 3) negative, or as being owned by a financial sponsor. We further identify financial sponsor-owned companies as "FS-4", "FS-5", "FS-6", or "FS-6 (minus)" (see section H.2).

### 1. Assessing financial policy

158. First, we determine if a company is owned by a financial sponsor. Given the intrinsic characteristics and aggressive nature of financial sponsor's strategies (i.e. short- to intermediate-term holding periods and the use of debt or debt-like instruments to maximize shareholder returns), we assign a financial risk profile assessment to a firm controlled by a financial sponsor that reflects the likely impact on leverage due to these strategies and we do not separately analyze management's financial discipline or financial policy framework.

159. If a company is not controlled by a financial sponsor, we evaluate management's financial discipline and financial policy framework. Management's financial discipline measures its tolerance for incremental financial risk or,

conversely, its willingness to maintain the same degree of financial risk or to lower it compared with recent cash flow/leverage metrics and our projected ratios for the next two years. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies. We do not assess these factors for financial sponsor controlled firms.

160. The financial discipline assessments can have a positive or negative influence on an enterprise's overall financial policy assessment, or can have no net effect. Conversely, the financial policy framework assessment cannot positively influence the overall financial policy assessment. It can constrain the overall financial policy assessment to no greater than neutral.

161. The separate assessments of a company's financial policy framework and financial discipline determine the financial policy adjustment.

162. We assess management's financial discipline as 1, positive; 2, neutral; or 3, negative. We determine the assessment by evaluating the predictability of an entity's expansion plans and shareholder return strategies. We take into account, generally, management's tolerance for material and unexpected negative changes in credit ratios or, instead, its plans to rapidly decrease leverage and keep credit ratios within stated boundaries.

163. A company's financial policy framework assessment is: 1, supportive or 2, non-supportive. We make the determination by assessing the comprehensiveness of a company's financial policy framework and whether financial targets are clearly communicated to a large number of stakeholders, and are well defined, achievable, and sustainable.

**Table 23**

**Financial Policy Assessments**

| Assessment | What it means | Guidance |
|---|---|---|
| Positive | Indicates that we expect management's financial policy decisions to have a positive impact on credit ratios over the time horizon, beyond what can be reasonably built in our forecasts on the basis of normalized operating and cash flow assumptions. An example would be when a credible management team commits to dispose of assets or raise equity over the short to medium term in order to reduce leverage. A company with a 1 financial risk profile will not be assigned a positive assessment. | If financial discipline is positive, and the financial policy framework is supportive |
| Neutral | Indicates that, in our opinion, future credit ratios won't differ materially over the time horizon beyond what we have projected, based on our assessment of management's financial policy, recent track record, and operating forecasts for the company. A neutral financial policy assessment effectively reflects a low probability of "event risk," in our view. | If financial discipline is positive, and the financial policy framework is non-supportive. Or when financial discipline is neutral, regardless of the financial policy framework assessment. |
| Negative | Indicates our view of a lower degree of predictability in credit ratios, beyond what can be reasonably built in our forecasts, as a result of management's financial discipline (or lack of it). It points to high event risk that management's financial policy decisions may depress credit metrics over the time horizon, compared with what we have already built in our forecasts based on normalized operating and cash flow assumptions. | If financial discipline is negative, regardless of the financial policy framework assessment |
| Financial Sponsor* | We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflects our presumption of some deterioration in credit quality in the medium term. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons. | We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together. |

*Assessed as FS-4, FS-5, FS-6, or FS-6 (minus).

### 2. Financial sponsor-controlled companies

164. We define a financial sponsor as an entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short-to-intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

165. We define financial sponsor-owned companies as companies that are owned 40% or more by a financial sponsor or a group of three or less financial sponsors and where we consider that the sponsor(s) exercise control of the company solely or together.

166. We differentiate between financial sponsors and other types of controlling shareholders and companies that do not have controlling shareholders based on our belief that short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

167. Financial sponsors often dictate policies regarding risk-taking, financial management, and corporate governance for the companies that they control. There is a common pattern of these investors extracting cash in ways that increase the companies' financial risk by utilizing debt or debt like instruments. Accordingly, the financial risk profile we assign to companies that are controlled by financial sponsors ordinarily reflect our presumption of some deterioration in credit quality or steadily high leverage in the medium term.

168. We assess the influence of financial sponsor ownership as "FS-4", "FS-5", "FS-6", and "FS-6 (minus)" depending on how aggressive we assume the sponsor will be and assign a financial risk profile accordingly (see table 24).

169. Generally, financial sponsor-owned issuers will receive an assessment of "FS-6" or "FS-6 (minus)", leading to a financial risk profile assessment of '6', under the criteria. A "FS-6" assessment indicates that, in our opinion, forecasted credit ratios in the medium term are likely be to be consistent with a '6' financial risk profile, based on our assessment of the financial sponsor's financial policy and track record. A "FS-6 (minus)" will likely be applied to companies that we forecast to have near-term credit ratios consistent with a '6' financial risk profile, but we believe the financial sponsor to be very aggressive and that leverage could increase materially even further from our forecasted levels.

170. In a small minority of cases, a financial sponsor-owned entity could receive an assessment of "FS-5". This assessment will apply only when we project that the company's leverage will be consistent with a '5' (aggressive) financial risk profile (see tables 17, 18, and 19), we perceive that the risk of releveraging is low based on the company's financial policy and our view of the owner's financial risk appetite, and liquidity is at least adequate.

171. In even rarer cases, we could assess the financial policy of a financial sponsor-owned entity as "FS-4". This assessment will apply only when all of the following conditions are met: other shareholders own a material (generally, at least 20%) stake, we expect the sponsor to relinquish control over the intermediate term, we project that leverage is currently consistent with a '4' (significant) financial risk profile (see tables 17, 18, and 19), the company has said it will maintain leverage at or below this level, and liquidity is at least adequate.

Table 24

**Financial Risk Profile Implications For Sponsor-Owned Issuers**

| Assessment | What it Means | Guidance |
|---|---|---|
| FS-4 | Financial risk profile set at '4' | Issuer must meet all of the following conditions:<br>• Other shareholders must own a material (no less than 20%) stake;<br>• We anticipate that the sponsor will relinquish control over the medium term;<br>• For issuers subject to Table 17 (standard volatility), debt to EBITDA is less than 4x, and we estimate that it will remain less than 4x. For issuers that are subject to Table 18 (medial volatility), debt to EBITDA is below 4.5x and we forecast it to remain below that level. Or for issuers subject to Table 19 (low volatility), debt to EBITDA is less than 5x and our estimation is it will remain below that level;<br>• The company has indicated a financial policy stipulating a level of leverage consistent with a significant or better financial risk profile (that is, debt to EBITDA of less than 4x when applying standard volatility tables, 4.5x when applying medial volatility tables, or less than 5x when applying low volatility tables) and<br>• We assess liquidity to be at least adequate, with adequate covenant headroom. |
| FS-5 | Financial risk profile set at '5' | Issuer must meet all of the following conditions:<br>• For issuers subject to the standard volatility table, debt to EBITDA is less than 5x, and we estimate that it will remain less than 5x. For issuers that are subject to the medial volatility table, debt to EBITDA is below 5.5x and we forecast it to remain below that level. Or for issuers subject to the low volatility table, debt to EBITDA is less than 6x and our estimation is it will remain below that level;<br>• We believe the risk of releveraging beyond 5x (standard volatility issuer), 5.5x (medial volatility issuer), or 6x (low volatility issuer) is low; and<br>• We assess liquidity to be at least adequate, with adequate covenant headroom. |
| FS-6 | Financial risk profile set at '6' | Standard & Poor's debt to EBITDA is greater than 5x (when applying the standard volatility table), greater than 5.5x (when applying the medial volatility table), or greater than 6x (when applying the low volatility table). However, we believe leverage is unlikely to increase meaningfully beyond these levels. |
| FS-6 (minus) | Financial risk profile set at '6', and rating reduced by one notch (unless this results in a final rating below 'B-') | In determining the anchor rating the financial risk profile is a '6', but we believe the track record of the financial sponsor indicates that leverage could increase materially from already high levels. |



### 3. Companies not controlled by a financial sponsor

172. For companies not controlled by a financial sponsor we evaluate management's financial discipline and financial policy framework to determine the influence on an entity's financial risk profile beyond what is implied by recent credit ratios and our cash flow and leverage forecasts. This influence can be positive, neutral, or negative.

173. We do not distinguish between management and a controlling shareholder that is not a financial sponsor when assessing these subfactors, as the controlling shareholder usually has the final say on financial policy.

### a) Financial discipline

174. The financial discipline assessment is based on management's leverage tolerance and the likelihood of event risk. The criteria evaluate management's potential appetite to incur unforeseen, higher financial risk over a prolonged period and the associated impact on credit measures. We also assess management's capacity and commitment to rapidly decrease debt leverage to levels consistent with its credit ratio targets.

175. This assessment therefore seeks to determine whether unforeseen actions by management to increase, maintain, or reduce financial risk are likely to occur during the next two to three years, with either a negative or positive effect, or none at all, on our baseline forecasts for the period.

176. This assessment is based on the leverage tolerance of a company's management, as reflected in its plans or history of acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263).

177. We assess financial discipline as positive, neutral, or negative, based on its potential impact on our forward-looking assessment of a firm's cash flow/leverage, as detailed in table 25. For example, a neutral assessment for leverage tolerance reflects our expectation that management's financial policy will unlikely lead to significant deviation from current and forecasted credit ratios. A negative assessment acknowledges a significant degree of event risk of increased leverage relative to our base-case forecast, resulting from the company's acquisition policy, its shareholder remuneration policy, or its organic growth strategy. A positive assessment indicates that the company is likely to take actions to reduce leverage, but we cannot confidently incorporate these actions into our baseline forward-looking assessment of cash flow/leverage.

178. A positive assessment indicates that management is committed and has the capacity to reduce debt leverage through the rapid implementation of credit enhancing measures, such as asset disposals, rights issues, or reductions in shareholder returns. In addition, management's track record over the past five years shows that it has taken actions to rapidly reduce unforeseen increases in debt leverage and that there have not been any prolonged periods when credit ratios were weaker than our expectations for the rating. Management, even if new, also has a track record of successful execution. Conversely, a negative assessment indicates management's financial policy allows for significant increase in leverage compared with both current levels and our forward-looking forecast under normal operating/financial conditions or does not have observable time limits or stated boundaries. Management has a track record of allowing for significant and prolonged peaks in leverage and there is no commitment or track record of management using mitigating measures to rapidly return to credit ratios consistent with our expectations.

179. As evidence of management's leverage tolerance, we evaluate its track record and plans regarding acquisitions, shareholder remuneration, and organic growth strategies (see Appendix E, paragraphs 258 to 263). Acquisitions could increase the risk that leverage will be higher than our base-case forecast if we view management's strategy as opportunistic or if its financial policy (if it exists) provides significant headroom for debt-financed acquisitions. Shareholder remuneration could also increase the risk of leverage being higher than our base-case forecast if management's shareholder reward policies are not particularly well defined or have no clear limits, management has a tolerance for shareholder returns exceeding operating cash flow, or has a track record of sustained cash returns despite weakening operating performance or credit ratios. Organic growth strategies can also result in leverage higher than our base-case forecast if these plans have no clear focus or investment philosophy, capital spending is fairly unpredictable,

or there is a track record of overspending or unexpected or rapid shifts in plans for new markets or products.

180. We also take into account management's track record and level of commitment to its stated financial policies, to the extent a company has a stated policy. Historical evidence and any deviations from stated policies are key elements in analyzing a company's leverage tolerance. Where material and unexpected deviation in leverage may occur (for example, on the back of operating weakness or acquisitions), we also assess management's plan to restore credit ratios to levels consistent with previous expectations through rapid and proactive non-organic measures. Management's track record to execute its deleveraging plan, its level of commitment, and the scope and timeframe of debt mitigating measures will be key differentiators in assessing a company's financial policy discipline.

**Table 25**

**Assessing Financial Discipline**

| Descriptor | What it means | Guidance |
|---|---|---|
| Positive | Management is likely to take actions that result in leverage that is lower than our base-case forecast, but can't be confidently included in our base-case assumptions. Event risk is low. | Management is committed and has capacity to reduce debt leverage and increase financial headroom through the rapid implementation of credit enhancing measures, in line with its stated financial policy, if any. This relates primarily to management's careful and moderate policy with regard to acquisitions and shareholder remuneration as well as to its organic growth strategy. The assessments are supported by historical evidence over the past five years of not showing any prolonged weakening in the company's credit ratios, or relative to our base-case credit metrics' assumptions. Management, even if new, has a track record of successful execution. |
| Neutral | Leverage is not expected to deviate materially from our base-case forecast. Event risk is moderate. | Management's financial discipline with regard to acquisitions, shareholder remuneration, as well as its organic growth strategy does not result in significantly different leverage as defined in its stated financial policy framework. |
| Negative | Leverage could become materially higher than our base-case forecast. Event risk is high. | Management's financial policy framework does not explicitly rule out a significant increase in leverage compared to our base-case assumptions, possibly reflecting a greater event risk with regard to its M&A and shareholder remuneration policy as well as to its organic growth strategy. These points are supported by historical evidence over the past five years of allowing for significant and prolonged peaks in leverage, which remained unmitigated by credit supporting measures by management. |

### b) Financial policy framework

181. The company's financial policy framework assesses the comprehensiveness, transparency, and sustainability of the entity's financial policies (see Appendix E, paragraphs 264-268). This will help determine whether there is a satisfactory degree of visibility into the issuer's future financial risk profile. Companies that have developed and sustained a comprehensive set of financial policies are more likely to build long-term, sustainable credit quality than those that do not.

182. We will assess a company's financial policy framework as supportive or non-supportive based on evidence that supports the characteristics listed below. In order for an entity to receive a supportive assessment for financial policy framework, there must be sufficient evidence of management's financial policies to back that assessment.

183. A company assessed as supportive will generally exhibit the following characteristics:

- Management has a comprehensive set of financial policies covering key areas of financial risk, including debt leverage and liability management. Financial targets are well defined and quantifiable.
- Management's financial policies are clearly articulated in public forums (such as public listing disclosures and investor presentations) or are disclosed to a limited number of key stakeholders such as main creditors or to the credit rating agencies. The company's adherence to these policies is satisfactory.

- Management's articulated financial policies are considered achievable and sustainable. This assessment takes into consideration historical adherence to articulated policies, existing financial risk profile, capacity to sustain capital structure through nonorganic means, demands of key stakeholders, and the stability of financial policy parameters over time.

184. A company receives a non-supportive assessment if it does not meet all the conditions for a supportive assessment. We expect a non-supportive assessment to be uncommon.

## I. Liquidity

185. Our assessment of liquidity focuses on monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis assesses the potential for a company to breach covenant tests related to declines in EBITDA, as well as its ability to absorb high-impact, low-probability events, the nature of the company's bank relationships, its standing in credit markets, and how prudent (or not) we believe its financial risk management to be (see "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," published Nov. 19, 2013).

## J. Management And Governance

186. The analysis of management and governance addresses how management's strategic competence, organizational effectiveness, risk management, and governance practices shape the issuer's competitiveness in the marketplace, the strength of its financial risk management, and the robustness of its governance. Stronger management of important strategic and financial risks may enhance creditworthiness (see "Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers," published Nov. 13, 2012).

## K. Comparable Ratings Analysis

187. The comparable ratings analysis is our last step in determining a SACP on a company. This analysis can lead us to raise or lower our anchor, after adjusting for the modifiers, on a company by one notch based on our overall assessment of its credit characteristics for all subfactors considered in arriving at the SACP. This involves taking a holistic review of a company's stand-alone credit risk profile, in which we evaluate an issuer's credit characteristics in aggregate. A positive assessment leads to a one-notch upgrade, a negative assessment leads to a one-notch downgrade, and a neutral assessment indicates no change to the anchor.

188. The application of comparable ratings analysis reflects the need to "fine-tune" ratings outcomes, even after the use of each of the other modifiers. A positive or negative assessment is therefore likely to be common rather than exceptional.

189. We consider our assessments of each of the underlying subfactors to be points within a possible range. Consequently, each of these assessments that ultimately generate the SACP can be at the upper or lower end, or at the mid-point, of such a range:

- A company receives a positive assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the higher end of the range;
- A company receives a negative assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be at the lower end of the range;
- A company receives a neutral assessment if we believe, in aggregate, its relative ranking across the subfactors typically to be in line with the middle of the range.

190. The most direct application of the comparable ratings analysis is in the following circumstances:

- Business risk assessment. If we expect a company to sustain a position at the higher or lower end of the ranges for the business risk category assessment, the company could receive a positive or negative assessment, respectively.
- Financial risk assessment and financial metrics. If a company's actual and forecasted metrics are just above (or just below) the financial risk profile range, as indicated in its cash flow/leverage assessment, we could assign a positive or negative assessment.

191. We also consider additional factors not already covered, or existing factors not fully captured, in arriving at the SACP. Such factors will generally reflect less frequently observed credit characteristics, may be unique, or may reflect unpredictability or uncertain risk attributes, both positive and negative.

192. Some examples that we typically expect could lead to a positive or negative assessment using comparable ratings analysis include:

- Short operating track record. For newly formed companies or companies that have experienced transformational events, such as a significant acquisition, a lack of an established track record of operating and financial performance could lead to a negative assessment until such a track record is established.
- Entities in transition. A company in the midst of changes that we anticipate will strengthen or weaken its creditworthiness and that are not already fully captured elsewhere in the criteria could receive a positive or negative assessment. Such a transition could occur following major divestitures or acquisitions, or during a significant overhaul of its strategy, business, or financial structure.
- Industry or macroeconomic trends. When industry or macroeconomic trends indicate a strengthening or weakening of the company's financial condition that is not already fully captured elsewhere in the criteria, the company could receive a positive or negative assessment, respectively.
- Unusual funding structures. A company with exceptional financial resources that the criteria do not capture in the traditional ratio or liquidity analysis, or in capital structure analysis, could receive a positive assessment.
- Contingent risk exposures. How well (or not) a company identifies, manages, and reserves for contingent risk exposures that can arise if guarantees are called, derivative contract break clauses are activated, or substantial lawsuits are lost could lead to a negative assessment.

## SUPERSEDED CRITERIA FOR ISSUERS WITHIN THE SCOPE OF THESE CRITERIA

- Companies Owned By Financial Sponsors: Rating Methodology, March 21, 2013
- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- How Stock Prices Can Affect An Issuer's Credit Rating, Sept. 26, 2008
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008
- Credit FAQ: Knowing The Investors In A Company's Debt And Equity, April 4, 2006

## RELATED CRITERIA

- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Criteria: Ratios And Adjustments, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria For Assigning 'CCC+', 'CCC', 'CCC-', And 'CC' Ratings, Oct. 1, 2012
- Principles Of Credit Ratings, published Feb. 16, 2011
- Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Criteria Guidelines For Recovery Ratings On Global Industrial Issuers' Speculative-Grade Debt, Aug. 10, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

## APPENDIXES

### A. Country Risk

**Table 26**

**Country And Regional Risk**

| Region |
|---|
| Western Europe |
| Southern Europe |
| Western + Southern Europe |
| East Europe |
| Central Europe |
| Eastern Europe and Central Asia |
| Middle East |
| Africa |
| North America |
| Central America |
| Latin America |
| The Caribbean |
| Asia-Pacific |
| Central Asia |
| East Asia |
| Australia NZ |

| Country | Region | GDP weighting (%) |
|---|---|---|
| South Africa | Africa | 30.2 |
| Egypt | Africa | 28.0 |
| Nigeria | Africa | 23.5 |
| Morocco | Africa | 8.9 |

**Table 26**

| Country And Regional Risk (cont.) | | |
|---|---|---|
| Tunisia | Africa | 5.4 |
| Senegal | Africa | 1.4 |
| Mozambique | Africa | 1.4 |
| Zambia | Africa | 1.2 |
| Indonesia | Asia-Pacific | 27.1 |
| Taiwan | Asia-Pacific | 20.1 |
| Thailand | Asia-Pacific | 14.4 |
| Malaysia | Asia-Pacific | 11.0 |
| Philippines | Asia-Pacific | 9.5 |
| Vietnam | Asia-Pacific | 7.1 |
| Bangladesh | Asia-Pacific | 6.8 |
| Sri Lanka | Asia-Pacific | 2.8 |
| Laos | Asia-Pacific | 0.4 |
| Papua New Guinea | Asia-Pacific | 0.4 |
| Mongolia | Asia-Pacific | 0.3 |
| Australia | Australia NZ | 88.2 |
| New Zealand | Australia NZ | 11.8 |
| Guatemala | Central America | 40.5 |
| Costa Rica | Central America | 30.2 |
| Panama | Central America | 29.3 |
| India | Central Asia | 86.5 |
| Pakistan | Central Asia | 9.3 |
| Kazakhstan | Central Asia | 4.2 |
| Poland | Central Europe | 46.3 |
| Czech Republic | Central Europe | 16.6 |
| Hungary | Central Europe | 11.3 |
| Slovakia | Central Europe | 7.7 |
| Bulgaria | Central Europe | 6.0 |
| Croatia | Central Europe | 4.6 |
| Lithuania | Central Europe | 3.8 |
| Latvia | Central Europe | 2.1 |
| Estonia | Central Europe | 1.6 |
| China | East Asia | 64.5 |
| Japan | East Asia | 23.6 |
| Korea | East Asia | 8.4 |
| Hong Kong | East Asia | 1.9 |
| Singapore | East Asia | 1.7 |
| Greece | East Europe | 77.5 |
| Slovenia | East Europe | 16.0 |
| Cyprus | East Europe | 6.5 |
| Russia | Eastern Europe and Central Asia | 80.4 |
| Ukraine | Eastern Europe and Central Asia | 10.8 |

**Table 26**

| Country And Regional Risk (cont.) | | |
|---|---|---|
| Belarus | Eastern Europe and Central Asia | 4.8 |
| Azerbaijan | Eastern Europe and Central Asia | 3.2 |
| Georgia | Eastern Europe and Central Asia | 0.9 |
| Brazil | Latin America | 35.3 |
| Mexico | Latin America | 26.3 |
| Argentina | Latin America | 11.1 |
| Colombia | Latin America | 7.5 |
| Venezuela | Latin America | 6.0 |
| Peru | Latin America | 4.9 |
| Chile | Latin America | 4.8 |
| Ecuador | Latin America | 2.0 |
| Uruguay | Latin America | 0.8 |
| El Salvador | Latin America | 0.7 |
| Paraguay | Latin America | 0.6 |
| Belize | Latin America | 0.0 |
| Turkey | Middle East | 42.8 |
| Saudi Arabia | Middle East | 28.2 |
| Israel | Middle East | 9.4 |
| Qatar | Middle East | 7.2 |
| Kuwait | Middle East | 6.3 |
| Oman | Middle East | 3.4 |
| Jordan | Middle East | 1.5 |
| Bahrain | Middle East | 1.2 |
| United States | North America | 91.5 |
| Canada | North America | 8.5 |
| Italy | Southern Europe | 52.6 |
| Spain | Southern Europe | 40.4 |
| Portugal | Southern Europe | 7.0 |
| Dominican Republic | The Caribbean | 75.4 |
| Jamaica | The Caribbean | 19.2 |
| Barbados | The Caribbean | 5.4 |
| Germany | Western Europe | 28.7 |
| United Kingdom | Western Europe | 21.3 |
| France | Western Europe | 20.7 |
| Netherlands | Western Europe | 6.5 |
| Belgium | Western Europe | 3.9 |
| Sweden | Western Europe | 3.6 |
| Switzerland | Western Europe | 3.3 |
| Austria | Western Europe | 3.3 |
| Norway | Western Europe | 2.6 |
| Denmark | Western Europe | 1.9 |
| Finland | Western Europe | 1.8 |

**Table 26**

| Country And Regional Risk (cont.) | | |
|---|---|---|
| Ireland | Western Europe | 1.8 |
| Luxembourg | Western Europe | 0.4 |
| Iceland | Western Europe | 0.1 |
| Malta | Western Europe | 0.1 |

## B. Competitive Position

**Table 27**

**List Of Industries, Subsectors, And Standard Competitive Position Group Profiles**

| Industry | Subsector | Competitive position group profile |
|---|---|---|
| Transportation cyclical | Airlines | Capital or asset focus |
| | Marine | Capital or asset focus |
| | Trucking | Capital or asset focus |
| Auto OEM | Automobile and truck manufacturers | Capital or asset focus |
| Metals and mining downstream | Aluminum | Commodity focus/cost driven |
| | Steel | Commodity focus/cost driven |
| Metals and mining upstream | Coal and consumable fuels | Commodity focus/cost driven |
| | Diversified metals and mining | Commodity focus/cost driven |
| | Gold | Commodity focus/cost driven |
| | Precious metals and minerals | Commodity focus/cost driven |
| Homebuilders and developers | Homebuilding | Capital or asset focus |
| Oil and gas refining and marketing | Oil and gas refining and marketing | Commodity focus/scale driven |
| Forest and paper products | Forest products | Commodity focus/cost driven |
| | Paper products | Commodity focus/cost driven |
| Building Materials | Construction materials | Capital or asset focus |
| Oil and gas integrated, exploration and production | Integrated oil and gas | Commodity focus/scale driven |
| | Oil and gas exploration and production | Commodity focus/scale driven |
| Agribusiness and commodity foods | Agricultural products | Commodity focus/scale driven |
| Real estate investment trusts (REITs) | Diversified REITs | Real-estate specific* |
| | Health care REITS | Real-estate specific* |
| | Industrial REITs | Real-estate specific* |
| | Office REITs | Real-estate specific* |
| | Residential REITs | Real-estate specific* |
| | Retail REITs | Real-estate specific* |
| | Specialized REITs | Not appplicable** |
| | Self-storage REITs | Real-estate specific* |
| | Net lease REITs | Real-estate specific* |
| | Real estate operating companies | Real-estate specific* |
| Leisure and sports | Casinos and gaming | Services and product focus |
| | Hotels, resorts, and cruise lines | Services and product focus |

**Table 27**

**List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)**

| | | |
|---|---|---|
| | Leisure facilities | Services and product focus |
| Commodity chemicals | Commodity chemicals | Commodity focus/cost driven |
| | Diversified chemicals | Commodity focus/cost driven |
| | Fertilizers and agricultural chemicals | Commodity focus/cost driven |
| Auto suppliers | Auto parts and equipment | Capital or asset focus |
| | Tires and rubber | Capital or asset focus |
| | Vehicle-related suppliers | Capital or asset focus |
| Aerospace and defense | Aerospace and defense | Services and product focus |
| Technology hardware and semiconductors | Communications equipment | Capital or asset focus |
| | Computer hardware | Capital or asset focus |
| | Computer storage and peripherals | Capital or asset focus |
| | Consumer electronics | Capital or asset focus |
| | Electronic equipment and instruments | Capital or asset focus |
| | Electronic components | Capital or asset focus |
| | Electronic manufacturing services | Capital or asset focus |
| | Technology distributors | Capital or asset focus |
| | Office electronics | Capital or asset focus |
| | Semiconductor equipment | Capital or asset focus |
| | Semiconductors | Capital or asset focus |
| Specialty Chemicals | Industrial gases | Capital or asset focus |
| | Specialty chemicals | Capital or asset focus |
| Capital Goods | Electrical components and equipment | Capital or asset focus |
| | Heavy equipment and machinery | Capital or asset focus |
| | Industrial componentry and consumables | Capital or asset focus |
| | Construction equipment rental | Capital or asset focus |
| | Industrial distributors | Services and product focus |
| Engineering and construction | Construction and engineering | Services and product focus |
| Railroads and package express | Railroads | Capital or asset focus |
| | Package express | Services and product focus |
| | Logistics | Services and product focus |
| Business and consumer services | Consumer services | Services and product focus |
| | Distributors | Services and product focus |
| | Facilities services | Services and product focus |
| | General support services | Services and product focus |
| | Professional services | Services and product focus |
| Midstream energy | Oil and gas storage and transportation | Commodity focus/scale driven |
| Technology software and services | Internet software and services | Services and product focus |
| | IT consulting and other services | Services and product focus |
| | Data processing and outsourced services | Services and product focus |
| | Application software | Services and product focus |
| | Systems software | Services and product focus |
| | Consumer software | Services and product focus |

**Table 27**

| List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.) | | |
|---|---|---|
| Consumer durables | Home furnishings | Services and product focus |
| | Household appliances | Services and product focus |
| | Housewares and specialties | Services and product focus |
| | Leisure products | Services and product focus |
| | Photographic products | Services and product focus |
| | Small appliances | Services and product focus |
| Containers and packaging | Metal and glass containers | Capital or asset focus |
| | Paper packaging | Capital or asset focus |
| Media and entertainment | Ad agencies and marketing services companies | Services and product focus |
| | Ad-supported internet content platforms | Services and product focus |
| | Broadcast TV networks | Services and product focus |
| | Cable TV networks | Services and product focus |
| | Consumer and trade magazines | Services and product focus |
| | Data/professional publishing | Services and product focus |
| | Directories | Services and product focus |
| | E-Commerce (services) | Services and product focus |
| | Educational publishing | Services and product focus |
| | Film and TV programming production | Capital or asset focus |
| | Miscellaneous media and entertainment | Services and product focus |
| | Motion picture exhibitors | Services and product focus |
| | Music publishing | Services and product focus |
| | Music recording | Services and product focus |
| | Newspapers | Services and product focus |
| | Outdoor advertising | Services and product focus |
| | Printing | Commodity focus/scale driven |
| | Radio broadcasters | Services and product focus |
| | Trade shows | Services and product focus |
| | TV stations | Services and product focus |
| Oil and gas drilling, equipment and services | Onshore contract drilling | Commodity focus/scale driven |
| | Offshore contract drilling | Capital or Asset Focus |
| | Oil and gas equipment and services (oilfield services) | Commodity focus/scale driven |
| Retail and restaurants | Catalog retail | Services and product focus |
| | Internet retail | Services and product focus |
| | Department stores | Services and product focus |
| | General merchandise stores | Services and product focus |
| | Apparel retail | Services and product focus |
| | Computer and electronics retail | Services and product focus |
| | Home improvement retail | Services and product focus |
| | Specialty stores | Services and product focus |
| | Automotive retail | Services and product focus |
| | Home furnishing retail | Services and product focus |

**Table 27**

**List Of Industries, Subsectors, And Standard Competitive Position Group Profiles (cont.)**

| | | |
|---|---|---|
| Health care services | Health care services | Commodity focus/scale driven |
| Transportation infrastructure | Airport services | National industries and utilities |
| | Highways | National industries and utilities |
| | Railtracks | National industries and utilities |
| | Marine ports and services | National industries and utilities |
| Environmental services | Environmental and facilities services | Services and product focus |
| Regulated utilities | Electric utilities | National industries and utilities |
| | Gas utilities | National industries and utilities |
| | Multi-utilities | National industries and utilities |
| | Water utilities | National industries and utilities |
| Unregulated power and gas | Independent power producers and energy traders | Capital or asset focus |
| | Merchant power | Capital or asset focus |
| Pharmaceuticals | Branded pharmaceuticals | Services and product focus |
| | Generic pharmaceuticals | Commodity focus/scale driven |
| Health care equipment | High-tech health care equipment | Product focus/scale driven |
| | Low-tech health care equipment | Commodity focus/scale driven |
| Branded nondurables | Brewers | Services and product focus |
| | Distillers and vintners | Services and product focus |
| | Soft drinks | Services and product focus |
| | Packaged foods and meats | Services and product focus |
| | Tobacco | Services and product focus |
| | Household products | Services and product focus |
| | Apparel, footwear, accessories, and luxury goods | Services and product focus |
| | Personal products | Services and product focus |
| Telecommunications and cable | Cable and satellite | Services and product focus |
| | Alternative carriers | Services and product focus |
| | Integrated telecommunication services | Services and product focus |
| | Wireless towers | Capital or asset focus |
| | Data center operators | Capital or asset focus |
| | Fiber-optic carriers | Capital or asset focus |
| | Wireless telecommunication services | Services and product focus |

*See "Key Credit Factors For The Real Estate Industry," published Nov. 19, 2013. **For specialized REITs, there is no standard CPGP, as the CPGP will vary based on the underlying industry exposure (e.g. a forest and paper products REIT).

### 1. Analyzing subfactors for competitive advantage

193. Competitive advantage is the first component of our competitive position analysis. Companies that possess a sustainable competitive advantage are able to capitalize on key industry factors or mitigate associated risks more effectively. When a company operates in more than one business, we analyze each segment separately to form an overall view of its competitive advantage. In assessing competitive advantage, we evaluate the following subfactors:

- Strategy;
- Differentiation/uniqueness, product positioning/bundling;

- Brand reputation and marketing;
- Product/service quality;
- Barriers to entry, switching costs;
- Technological advantage and capabilities, technological displacement; and
- Asset profile.

### a) Strategy

194. A company's business strategy will enhance or undermine its market entrenchment and business stability. Compelling business strategies can create a durable competitive advantage and thus a relatively stronger competitive position. We form an opinion as to the source and sustainability (if any) of the company's competitive advantage relative to its peers'. The company may have a differentiation advantage (i.e., brand, technology, regulatory) or a cost advantage (i.e., lower cost producer/servicer at the same quality level), or a combination.

195. Our assessment of a company's strategy is informed by a company's historical performance and how realistic we view its forward-looking business objectives to be. These may include targets for market shares, the percentage of revenues derived from new products, price versus the competition's, sales or profit growth, and required investment levels. We evaluate these objectives in the context of industry dynamics and the attractiveness of the markets in which the company participates.

### b) Differentiation/uniqueness, product positioning/bundling

196. The attributes of product or service differentiation vary by sector, and may include product or services features, performance, durability, reliability, delivery, and comprehensiveness, among other measures. The intensity of competition may be lower where buyers perceive the product or service to be highly differentiated or to have few substitutes. Conversely, products and services that lack differentiation, or offer little value-added in the eyes of customers, are generally commodity-type products that primarily compete on price. Competition intensity will often be highest where limited or moderate investment (R&D, capital expenditures, or advertising) or low employee skill levels (for service businesses) are required to compete. Independent market surveys, media commentaries, market share trends, and evidence of leading or lagging when it comes to raising or lowering prices can indicate varying degrees of product differentiation.

197. Product positioning influences how companies are able to extend or protect market shares by offering popular products or services. A company's abilities to replace aging products with new ones, or to launch product extensions, are important elements of product positioning. In addition, the ability to sell multiple products or services to the same customer, known as bundling or cross-selling, (for instance, offering an aftermarket servicing contract together with the sale of a new appliance) can create a competitive advantage by increasing customers' switching costs and fostering loyalty.

### c) Brand reputation and marketing

198. Brand equity measures the price premium a company receives based on its brand relative to the generic equivalent. High brand equity typically translates into customer loyalty, built partially via marketing campaigns. One measure of advertising effectiveness can be revenue growth compared with the increase in advertising expenses.

199. We also analyze re-investment and advertising strategies to anticipate potential strengthening or weakening of a

company's brand. A company's track record of boosting market share and delivering attractive margins could indicate its ability to build and maintain brand reputation.

### d) Product/service level quality

200. The strength and consistency of a value proposition is an important factor contributing to a sustainable competitive advantage. Value proposition encompasses the key features of a product or a service that convince customers that their purchase has the right balance between price and quality. Customers generally perceive a product or a service to be good if their expectations are consistently met. Quality, both actual and perceived, can help a company attract and retain customers. Conversely, poor product and service quality may lead to product recalls, higher-than-normal product warnings, or service interruptions, which may reduce demand. Measures of customer satisfaction and retention, such as attrition rates and contract renewal rates, can help trace trends in product/service quality.

201. Maintaining the value proposition requires consistency and adaptability around product design, marketing, and quality-related operating controls. This is pertinent where product differentiation matters, as is the case in most noncommodity industries, and especially so where environmental or human health (concerns for the chemical, food, and pharmaceutical industries) adds a liability dimension to the quality and value proposition. Similarly, regulated utilities (which often do not set their own prices) typically focus on delivering uninterrupted service, often to meet the standards set by their regulator.

### e) Barriers to entry, switching costs

202. Barriers to entry can reduce or eliminate the threat of new market entrants. Where they are effective, these barriers can lead to more predictable revenues and profits, by limiting pricing pressures and customer losses, lowering marketing costs, and improving operating efficiency. While barriers to entry may enable premium pricing, a dominant player may rationally choose pricing restraint to further discourage new entrants.

203. Barriers to entry can be one or more of: a natural or regulatory monopoly; supportive regulation; high transportation costs; an embedded customer base that would incur high switching costs; a proprietary product or service; capital or technological intensiveness.

204. A natural monopoly may result from unusually high requirements for capital and operating expenditures that make it uneconomic for a market to support more than a single, dominant provider. The ultimate barrier to entry is found among regulated utilities, which provide an essential service in their 'de juris' monopolies and receive a guaranteed rate of return on their investments. A supportive regulatory regime can include rules and regulations with high hurdles that discourage competitors, or mandate so many obligations for a new entrant as to make market entry financially unviable.

205. In certain industrial sectors, proprietary access to a limited supply of key raw materials or skilled labor, or zoning laws that effectively preclude a new entrant, can provide a strong barrier to entry. Factors such as relationships, long-term contracts or maintenance agreements, or exclusive distribution agreements can result in a high degree of customer stickiness. A proprietary product or service that's protected by a copyright or patent can pose a significant hurdle to new competitors.

### f) Technological advantage and capabilities, technological displacement

206. A company may benefit from a proprietary technology that enables it to offer either a superior product or a commodity-type product at a materially lower cost. Proven research and development (R&D) capabilities can deliver a differentiated, superior product or service, as in the pharmaceutical or high tech sectors. However, optimal R&D strategies or the importance or effectiveness of patent protection differ by industry, stage of product development, and product lifecycle.

207. Technological displacement can be a threat in many industries; new technologies or extensions of current ones can effectively displace a significant portion of a company's products or services.

### g) Asset profile

208. A company's asset profile is a reflection of its reinvestment, which creates tangible or intangible assets, or both. Companies in similar sectors and industries usually have similar reinvestment options and, thus, their asset profiles tend to be comparable. The reinvestment in "heavy" industries, such as oil and gas, metals and mining, and automotive, tends to produce more tangible assets, whereas the reinvestment in certain "light" industries, such as services, media and entertainment, and retail, tends to produce more intangible assets.

209. We evaluate how a company's asset profile supports or undermines its competitive advantage by reviewing its manufacturing or service creation capabilities and investment requirements, its distribution capabilities, and its track record and commitment to reinvesting in its asset base. This may include a review of the company's ability to attract and retain a talented workforce; its degree of vertical integration and how that may help or hinder its ability to secure supply sources, control the value-added part of its production chain, or adjust to technological developments; or its ability develop a broad and strong distribution network.

### 2. Analyzing subfactors for scale, scope, and diversity

210. In assessing the relative strength of this component, we evaluate four subfactors:

- Diversity of product or service range;
- Geographic diversity;
- Volumes, size of markets and revenues, and market shares; and
- Maturity of products or services.

211. In a given industry, entities with a broader mix of business activities are typically lower risk, and entities with a narrower mix are higher risk. High concentration of business volumes by product, customer, or geography, or a concentration in the production footprint or supplier base, can lead to less stable and predictable revenues and profits. Comparatively broader diversity helps a company withstand economic, competitive, or technological threats better than its peers.

212. There is no minimum size criterion, although size often provides a measure of diversification. Size and scope of operations is important relative to those of industry peers, though not in absolute terms. While relatively smaller companies can enjoy a high degree of diversification, they will likely be, almost by definition, more concentrated in terms of product, number of customers, or geography than their larger peers in the same industry.

213. Successful and continuing diversification supports a stronger competitive position. Conversely, poor diversification

weakens overall competitive position. For example, a company will weaken its overall business position if it enters new product lines and countries where it has limited expertise and lacks critical mass to be a real competitor to the incumbent market leaders. The weakness is greater when the new products or markets are riskier than the traditional core business.

214. Where applicable, we also include under scale, scope, and diversity an assessment of the potential benefits derived from unconsolidated (or partially consolidated) investments in strategic assets. The relative significance of such an investment and whether it is in an industry that exhibits high or, conversely, low correlation with the issuer's businesses would be considered in determining its potential benefits to scale, scope, and diversity. This excludes nonstrategic, financial investments, the analysis of which does not fall under the competitive position criteria but, instead, under the capital structure criteria.

### a) Diversity of product or service range

215. The concentration of business volumes or revenues in a particular or comparatively small set of products or services can lead to less stable revenues and profits. Even if this concentration is in an attractive product or service, it may be a weakness. Likewise, the concentration of business volumes with a particular customer or a small group of customers, or the reliance on one or a few suppliers, can expose the company to a potentially greater risk of losing and having to replace related revenues and profits. On the other hand, successful diversification across products, customers, and/or suppliers can lead to more stable and predictable revenues and profits, which supports a stronger assessment of scale, scope, and diversity.

216. The relative contribution of different products or services to a company's revenues or profits helps us gauge its diversity. We also evaluate the correlation of demand between product or services lines. High correlation in demand between seemingly different product or service lines will accentuate volume declines during a weak part of the business cycle.

217. In most sectors, the share of revenue a company receives from its largest five to 10 customers or counterparties reveals how diversified its customer base is. However, other considerations such as the stability and credit quality of that customer base, and the company's ability to retain significant customers, can be mitigating or accentuating factors in our overall evaluation. Likewise, supplier dependency can often be measured based on a supplier's share of a company's operating or capital costs. However, other factors, such as the degree of interdependence between the company and its supplier(s), the substitutability of key supply sources, and the company's presumed ability to secure alternative supply without incurring substantial switching costs, are important considerations. Low switching costs (i.e. limited impact on input price, quality, or delivery times as a result of having to adapt to a new supply chain partner) can mitigate a high level of concentration.

### b) Geographic diversity

218. We assess geographic diversity both from the standpoint of the breadth of the company's served or addressable markets, and from the standpoint of how geographically concentrated its facilities are.

219. The concentration of business volumes and revenues within a particular region can lead to greater exposure to economic factors affecting demand for a company's goods or services in that region. Even if the company's volumes and revenues are concentrated in an attractive region, it may still be vulnerable to a significant drop in demand for its

goods and services. Conversely, a company that serves multiple regions may benefit from different demand conditions in each, possibly resulting in greater revenue stability and more consistent profitability than a more focused peer's. That said, we consider geographic diversification in the context of the industry and the size of the local or regional economy. For instance, companies operating in local industries (such as food retailers) may benefit from a well-entrenched local position.

220. Generally, though, geographically concentrated production or service operations can expose a company to the risk of disruption, and damage revenues and profitability. Even when country risks don't appear significant, a company's vulnerability to exogenous factors (for example, natural disasters, labor or political unrest) increases with geographic concentration.

### c) Volumes, size of markets and revenues, market share

221. Absolute sales or unit volumes and market share do not, by themselves, support a strong assessment of scale, scope, and diversity. Yet superior market share is a positive, since it may indicate a broad range of operations, products, or services.

222. We view volume stability (relative to peers') as a positive especially when: a company has demonstrated it during an economic downturn; if it has been achieved without relying on greater price concessions than competitors have made; and when it is likely to be sustained in the future. However, volume stability combined with shrinking market share could be evidence of a company's diminishing prospects for future profitability. We assess the predictability of business volumes and the likely degree of future volume stability by analyzing the company's performance relative to peers' on several industry factors: cyclicality; ability to adapt to technological and regulatory threats; the profile of the customer base (stickiness); and the potential life cycle of the company's products or services.

223. Depending on the industry sector, we measure a company's relative size and market share based on unit sales; the absolute amount of revenues; and the percentage of revenues captured from total industry revenues. We also adjust for industry and company specific qualitative considerations. For example, if an industry is particularly fragmented and has a number of similarly sized participants, none may have a particular advantage or disadvantage with respect to market share.

### d) Maturity of products or services

224. The degree of maturity and the relative position on the lifecycle curve of the company's product or service portfolio affect the stability and sustainability of its revenues and margins. It is important to identify the stage of development of a company's products or services in order to measure the life cycle risks that may be associated with key products or services.

225. Mature products or services (e.g. consumer products or broadcast programming) are not necessarily a negative, in our view, if they still contribute reliable profits. If demand is declining for a company's product or service, we examine its track record on introducing new products with staying power. Similarly, a company's track record with product launches is particularly relevant.

### 3. Analyzing subfactors for operating efficiency

226. In assessing the relative strength of this component, we consider four subfactors:

- Cost structure,
- Manufacturing processes,
- Working capital management, and
- Technology.

227. To the extent a company has high operating efficiency, it should be able to generate better profit margins than peers that compete in the same markets, whatever the prevailing market conditions. The ability to minimize manufacturing and other operational costs and thus maximize margins and cash flow--for example, through manufacturing excellence, cost control, and diligent working capital management--will provide the funds for research and development, marketing, and customer service.

#### a) Cost structure

228. Companies that are well positioned from a cost standpoint will typically enjoy higher capacity utilization and be more profitable over the course of the business cycle. Cost structure and cost control are keys to generating strong profits and cash flow, particularly for companies that produce commodities, operate in mature industries, or face pricing pressures. It is important to consider whether a company or any of its competitors has a sustainable cost advantage, which can be based on access to cheaper energy, favorable manufacturing locations, or lower and more flexible labor costs, for example.

229. Where information is available, we examine a company's fixed versus variable cost mix as an indication of operating leverage, a measure of how revenue growth translates into growth in operating income. A company with significant operating leverage may witness dramatic declines in operating profit if unit volumes fall, as during cyclical downturns. Conversely, in an upturn, once revenues pass the breakeven point, a substantial percentage of incremental revenues typically becomes profit.

#### b) Manufacturing process

230. Capital intensity characterizes many heavy manufacturing sectors that require minimum volumes to produce acceptable profits, cash flow, and return on assets. We view capacity utilization through the business cycle (combined with the cost base) as a good indication of manufacturers' ability to maintain profits in varying economic scenarios. Our capacity utilization assessment is based on a company's production capacity across its manufacturing footprint. In addition, we consider the direction of a company's capacity utilization in light of our unit sales expectations, as opposed to analyzing it plant-by-plant.

231. Labor relations remain an important focus in our analysis of operating efficiency for manufacturers. Often, a company's labor cost structure is driven by its history of contractual negotiations and the countries in which it operates. We examine the rigidity or flexibility of a company's labor costs and the extent to which it relies on labor rather than automation. We analyze labor cost structure by assessing the extent of union representation, wage and benefit costs as a share of cost of goods sold (when available), and by assessing the balance of capital equipment vs. labor input in the manufacturing process. We also incorporate trends in a company's efforts to transfer labor costs from high-cost to low-cost regions.

### c) Working capital management

232. Working capital management--of current or short-term assets and liabilities--is a key factor in our evaluation of operating efficiency. In general, companies with solid working capital management skills exhibit shorter cash conversion cycles (defined as days' investment in inventory and receivables less days' investment in accounts payable) than their lower-skilled peers. Short cash-conversion cycles could, for instance, demonstrate that a company has a stronger position in the supply chain (for example, requiring suppliers or dealers to hold more of its inventory). This allows a company to direct more capital than its peers can to other areas of investment.

### d) Technology

233. Technology can play an important role in achieving superior operating efficiency through effective yield management (by improving input/output ratios), supply chain automation, and cost optimization.

234. Achieving high yield management is particularly important in industries with limited inventory and high fixed costs, such as transportation, lodging, media, and retail. The most efficient airlines can achieve higher revenue per available seat mile than their peers, while the most efficient lodging companies can achieve a higher revenue per available room than their peers. Both industries rely heavily on technology to effectively allocate inventory (seats and rooms) to maximize sales and profitability.

235. Effective supply chain automation systems enable companies to reduce investments in inventory and better forecast future orders based on current trends. By enabling electronic data interchange between supplier and retailer, such systems help speed orders and reorders for goods by quickly pinpointing which merchandise is selling well and needs restocking. They also identify slow moving inventory that needs to be marked down, making space available for fresh merchandise.

236. Effective use of technology can also help hold down costs by improving productivity via automation and workflow management. This can reduce selling, general, and administrative costs, which usually represent a substantial portion of expenditures for industries with high fixed costs, thus boosting earnings.

## 4. Industry-specific SER parameters

**Table 28**

**SER Calibration By Industry Based On EBITDA**

| | --Volatility of profitability assessment*-- | | | | | |
|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** |
| Transportation cyclical | =<10% | >10%-14% | >14%-22% | >22%-33% | >33%-76% | >76% |
| Auto OEM | =<25% | >25%-33% | >33%-35% | >35%-40% | >40%-46% | >46% |
| Metals and mining downstream | =<16% | >16%-31% | >31%-42% | >42%-53% | >53%-82% | >82% |
| Metals and mining upstream | =<16% | >16%-23% | >23%-28% | >28%-34% | >34%-59% | >59% |
| Homebuilders and developers | =<19% | >19%-33% | >33%-46% | >46%-65% | >65%-95% | >95% |
| Oil and gas refining and marketing | =<14% | >14%-21% | >21%-35% | >35%-46% | >46%-82% | >82% |
| Forest and paper products | =<9% | >9%-18% | >18%-26% | >26%-51% | >51%-114% | >114% |
| Building materials | =<9% | >9%-16% | >16%-19% | >19%-24% | >24%-33% | >33% |
| Oil and gas integrated, exploration and production | =<12% | >12%-19% | >19%-22% | >22%-28% | >28%-38% | >38% |
| Agribusiness and commodity foods | =<12% | >12%-19% | >19%-25% | >25%-39% | >39%-57% | >57% |

**Table 28**

**SER Calibration By Industry Based On EBITDA (cont.)**

| | | | | | | |
|---|---|---|---|---|---|---|
| Real estate investment trusts (REITs) | =<5% | >5%-9% | >9%-13% | >13%-20% | >20%-32% | >32% |
| Leisure and sports | =<5% | >5%-9% | >9%-12% | >12%-16% | >16%-24% | >24% |
| Commodity chemicals | =<14% | >14%-19% | >19%-28% | >28%-37% | >37%-51% | >51% |
| Auto suppliers | =<15% | >15%-20% | >20%-26% | >26%-32% | >32%-45% | >45% |
| Aerospace and defense | =<6% | >6%-9% | >9%-15% | >15%-24% | >24%-41% | >41% |
| Technology hardware and semiconductors | =<11% | >11%-15% | >15%-22% | >22%-31% | >31%-58% | >58% |
| Specialty chemicals | =<5% | >5%-10% | >10%-14% | >14%-23% | >23%-36% | >36% |
| Capital goods | =<12% | >12%-16% | >16%-21% | >21%-30% | >30%-45% | >45% |
| Engineering and construction | =<9% | >9%-14% | >14%-20% | >20%-28% | >28%-39% | >39% |
| Railroads and package express | =<5% | >5%-8% | >8%-10% | >10%-13% | >13%-22% | >22% |
| Business and consumer services | =<4% | >4%-8% | >8%-11% | >11%-16% | >16%-30% | >30% |
| Midstream energy | =<5% | >5%-9% | >9%-11% | >11%-15% | >15%-31% | >31% |
| Technology software and services | =<4% | >4%-9% | >9%-14% | >14%-19% | >19%-33% | >33% |
| Consumer durables | =<7% | >7%-10% | >10%-13% | >13%-19% | >19%-35% | >35% |
| Containers and packaging | =<5% | >5%-7% | >7%-12% | >12%-18% | >18%-26% | >26% |
| Media and entertainment | =<6% | >6%-10% | >10%-14% | >14%-20% | >20%-29% | >29% |
| Oil and gas drilling, equipment and services | =<16% | >16%-22% | >22%-28% | >28%-44% | >44%-62% | >62% |
| Retail and restaurants | =<4% | >4%-8% | >8%-11% | >11%-16% | >16%-26% | >26% |
| Health care services | =<4% | >4%-5% | >5%-9% | >9%-12% | >12%-19% | >19% |
| Transportation infrastructure | =<2% | >2%-4% | >4%-7% | >7%-12% | >12%-19% | >19% |
| Environmental services | =<5% | >5%-9% | >9%-13% | >13%-22% | >22%-29% | >29% |
| Regulated utilities | =<4% | >4%-7% | >7%-9% | >9%-14% | >14%-26% | >26% |
| Unregulated power and gas | =<7% | >7%-16% | >16%-20% | >20%-29% | >29%-47% | >47% |
| Pharmaceuticals | =<5% | >5%-8% | >8%-11% | >11%-17% | >17%-32% | >32% |
| Health care equipment | =<3% | >3%-5% | >5%-6% | >6%-10% | >10%-25% | >25% |
| Branded nondurables | =<4% | >4%-7% | >7%-10% | >10%-15% | >15%-43% | >43% |
| Telecommunications and cable | =<3% | >3%-6% | >6%-9% | >9%-13% | >13%-23% | >23% |
| Overall | =<5% | >5%-9% | >9%-15% | >15%-23% | >23%-43% | >43% |

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

**Table 29**

**SER Calibration By Industry Based On EBITDA Margin**

| | --Volatility of profitability assessment*-- | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 |
| Transportation cyclical | =<4% | >4%-8% | >8%-16% | >16%-28% | >28%-69% | >69% |
| Auto OEM | =<15% | >15%-19% | >19%-29% | >29%-31% | >31%-45% | >45% |
| Metals and mining downstream | =<10% | >10%-18% | >18%-26% | >26%-36% | >36%-56% | >56% |
| Metals and mining upstream | =<8% | >8%-10% | >10%-14% | >14%-19% | >19%-31% | >31% |
| Homebuilders and developers | =<10% | >10%-18% | >18%-30% | >30%-56% | >56%-114% | >114% |
| Oil and gas refining and marketing | =<12% | >12%-22% | >22%-28% | >28%-42% | >42%-71% | >71% |
| Forest and paper products | =<8% | >8%-13% | >13%-21% | >21%-41% | >41%-117% | >117% |
| Building materials | =<4% | >4%-8% | >8%-13% | >13%-18% | >18%-23% | >23% |

**Table 29**

**SER Calibration By Industry Based On EBITDA Margin (cont.)**

| | | | | | | |
|---|---|---|---|---|---|---|
| Oil and gas integrated, exploration and production | =<4% | >4%-6% | >6%-8% | >8%-13% | >13%-22% | >22% |
| Agribusiness and commodity foods | =<9% | >9%-14% | >14%-18% | >18%-27% | >27%-100% | >100% |
| Real estate investment trusts (REITs) | =<2% | >2%-5% | >5%-8% | >8%-13% | >13%-34% | >34% |
| Leisure and sports | =<3% | >3%-5% | >5%-6% | >6%-9% | >9%-18% | >18% |
| Commodity chemicals | =<9% | >9%-14% | >14%-18% | >18%-25% | >25%-37% | >37% |
| Auto suppliers | =<9% | >9%-13% | >13%-18% | >18%-23% | >23%-40% | >40% |
| Aerospace and defense | =<3% | >3%-6% | >6%-7% | >7%-12% | >12%-24% | >24% |
| Technology hardware and semiconductors | =<7% | >7%-10% | >10%-15% | >15%-21% | >21%-62% | >62% |
| Specialty chemicals | =<3% | >3%-6% | >6%-10% | >10%-19% | >19%-28% | >28% |
| Capital goods | =<6% | >6%-9% | >9%-13% | >13%-20% | >20%-33% | >33% |
| Engineering and construction | =<6% | >6%-8% | >8%-12% | >12%-17% | >17%-26% | >26% |
| Railroads and package express | =<2% | >2%-6% | >6%-8% | >8%-10% | >10%-17% | >17% |
| Business and consumer services | =<3% | >3%-5% | >5%-7% | >7%-12% | >12%-22% | >22% |
| Midstream energy | =<3% | >3%-6% | >6%-9% | >9%-14% | >14%-28% | >28% |
| Technology software and services | =<3% | >3%-6% | >6%-10% | >10%-15% | >15%-30% | >30% |
| Consumer durables | =<4% | >4%-8% | >8%-11% | >11%-15% | >15%-26% | >26% |
| Containers and packaging | =<5% | >5%-7% | >7%-9% | >9%-15% | >15%-22% | >22% |
| Media and entertainment | =<4% | >4%-6% | >6%-9% | >9%-14% | >14%-24% | >24% |
| Oil and gas drilling, equipment and services | =<6% | >6%-12% | >12%-16% | >16%-22% | >22%-32% | >32% |
| Retail and restaurants | =<3% | >3%-5% | >5%-7% | >7%-12% | >12%-21% | >21% |
| Health care services | =<3% | >3%-5% | >5%-6% | >6%-8% | >8%-15% | >15% |
| Transportation infrastructure | =<1% | >1%-3% | >3%-5% | >5%-7% | >7%-15% | >15% |
| Environmental services | =<3% | >3%-4% | >4%-6% | >6%-10% | >10%-24% | >24% |
| Regulated utilities | =<4% | >4%-7% | >7%-9% | >9%-14% | >14%-24% | >24% |
| Unregulated power and gas | =<6% | >6%-10% | >10%-15% | >15%-23% | >23%-41% | >41% |
| Pharmaceuticals | =<4% | >4%-5% | >5%-7% | >7%-10% | >10%-21% | >21% |
| Health care equipment | =<2% | >2%-4% | >4%-5% | >5%-10% | >10%-16% | >16% |
| Branded nondurables | =<3% | >3%-6% | >6%-9% | >9%-13% | >13%-28% | >28% |
| Telecommunications and cable | =<2% | >2%-4% | >4%-5% | >5%-7% | >7%-13% | >13% |
| Overall | =<3% | >3%-6% | >6%-10% | >10%-16% | >16%-32% | >32% |

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

**Table 30**

**SER Calibration By Industry Based On Return On Capital**

| | --Volatility of profitability assessment*-- | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 |
| Transportation cyclical | =<14% | >14%-28% | >28%-39% | >39%-53% | >53%-156% | >156% |
| Auto OEM | =<42% | >42%-64% | >64%-74% | >74%-86% | >86%-180% | >180% |
| Metals and mining downstream | =<25% | >25%-32% | >32%-43% | >43%-53% | >53%-92% | >92% |
| Metals and mining upstream | =<22% | >22%-30% | >30%-38% | >38%-45% | >45%-93% | >93% |
| Homebuilders and developers | =<12% | >12%-31% | >31%-50% | >50%-70% | >70%-88% | >88% |

**Table 30**

| SER Calibration By Industry Based On Return On Capital (cont.) | | | | | | |
|---|---|---|---|---|---|---|
| Oil and gas refining and marketing | =<14% | >14%-30% | >30%-48% | >48%-67% | >67%-136% | >136% |
| Forest and paper products | =<10% | >10%-22% | >22%-40% | >40%-89% | >89%-304% | >304% |
| Building materials | =<13% | >13%-20% | >20%-26% | >26%-36% | >36%-62% | >62% |
| Oil and gas integrated, exploration and production | =<16% | >16%-22% | >22%-31% | >31%-43% | >43%-89% | >89% |
| Agribusiness and commodity foods | =<12% | >12%-15% | >15%-29% | >29%-55% | >55%-111% | >111% |
| Real estate investment trusts (REITs) | =<8% | >8%-14% | >14%-20% | >20%-26% | >26%-116% | >116% |
| Leisure and sports | =<11% | >11%-17% | >17%-26% | >26%-34% | >34%-64% | >64% |
| Commodity chemicals | =<19% | >19%-28% | >28%-41% | >41%-50% | >50%-73% | >73% |
| Auto suppliers | =<20% | >20%-39% | >39%-50% | >50%-67% | >67%-111% | >111% |
| Aerospace and defense | =<7% | >7%-13% | >13%-19% | >19%-27% | >27%-61% | >61% |
| Technology hardware and semiconductors | =<8% | >8%-21% | >21%-34% | >34%-49% | >49%-113% | >113% |
| Specialty chemicals | =<5% | >5%-18% | >18%-28% | >28%-43% | >43%-64% | >64% |
| Capital goods | =<15% | >15%-24% | >24%-31% | >31%-45% | >45%-121% | >121% |
| Engineering and construction | =<12% | >12%-21% | >21%-23% | >23%-33% | >33%-54% | >54% |
| Railroads and package express | =<3% | >3%-11% | >11%-17% | >17%-20% | >20%-27% | >27% |
| Business and consumer services | =<9% | >9%-17% | >17%-23% | >23%-40% | >40%-87% | >87% |
| Midstream energy | =<5% | >5%-11% | >11%-17% | >17%-22% | >22%-34% | >34% |
| Technology software and services | =<8% | >8%-21% | >21%-35% | >35%-65% | >65%-105% | >105% |
| Consumer durables | =<8% | >8%-13% | >13%-20% | >20%-35% | >35%-60% | >60% |
| Containers and packaging | =<6% | >6%-14% | >14%-23% | >23%-35% | >35%-52% | >52% |
| Media and entertainment | =<9% | >9%-17% | >17%-26% | >26%-40% | >40%-86% | >86% |
| Oil and gas drilling, equipment and services | =<25% | >25%-33% | >33%-45% | >45%-65% | >65%-90% | >90% |
| Retail and restaurants | =<6% | >6%-14% | >14%-18% | >18%-26% | >26%-69% | >69% |
| Health care services | =<6% | >6%-10% | >10%-15% | >15%-25% | >25%-44% | >44% |
| Transportation infrastructure | =<5% | >5%-9% | >9%-12% | >12%-16% | >16%-27% | >27% |
| Environmental Services | =<7% | >7%-12% | >12%-24% | >24%-35% | >35%-72% | >72% |
| Regulated utilities | =<6% | >6%-9% | >9%-13% | >13%-20% | >20%-36% | >36% |
| Unregulated power and gas | =<14% | >14%-19% | >19%-29% | >29%-55% | >55%-117% | >117% |
| Pharmaceuticals | =<6% | >6%-8% | >8%-15% | >15%-20% | >20%-33% | >33% |
| Health care equipment | =<4% | >4%-8% | >8%-19% | >19%-31% | >31%-81% | >81% |
| Branded nondurables | =<6% | >6%-10% | >10%-17% | >17%-29% | >29%-63% | >63% |
| Telecommunications and cable | =<7% | >7%-13% | >13%-19% | >19%-26% | >26%-60% | >60% |
| Overall | =<7% | >7%-15% | >15%-23% | >23%-38% | >38%-81% | >81% |

*The data ranges include the values up to and including the upper bound. As an example, for a range of 5%-9%, a value of 5% is excluded, while a value of 9% is included; the numbers are rounded to the nearest whole number for presentation purposes.

## C. Cash Flow/Leverage Analysis

### 1. The merits and drawbacks of each cash flow measure

### a) EBITDA

237. EBITDA is a widely used, and therefore a highly comparable, indicator of cash flow, although it has significant limitations. Because EBITDA derives from the income statement entries, it can be distorted by the same accounting issues that limit the use of earnings as a basis of cash flow. In addition, interest can be a substantial cash outflow for speculative-grade companies and therefore EBITDA can materially overstate cash flow in some cases. Nevertheless, it serves as a useful and common starting point for cash flow analysis and is useful in ranking the financial strength of different companies.

### b) Funds from operations (FFO)

238. FFO is a hybrid cash flow measure that estimates a company's inherent ability to generate recurring cash flow from its operations independent of working capital fluctuations. FFO estimates the cash flow available to the company before working capital, capital spending, and discretionary items such as dividends, acquisitions, etc.

239. Because cash flow from operations tends to be more volatile than FFO, FFO is often used to smooth period-over-period variation in working capital. We consider it a better proxy of recurring cash flow generation because management can more easily manipulate working capital depending on its liquidity or accounting needs. However, we do not generally rely on FFO as a guiding cash flow measure in situations where assessing working capital changes is important to judge a company's cash flow generating ability and general creditworthiness. For example, for working-capital-intensive industries such as retailing, operating cash flow may be a better indicator than FFO of the firm's actual cash generation.

240. FFO is a good measure of cash flow for well-established companies whose long-term viability is relatively certain (i.e., for highly rated companies). For such companies, there can be greater analytical reliance on FFO and its relation to the total debt burden. FFO remains very helpful in the relative ranking of companies. In addition, more established, healthier companies usually have a wider array of financing possibilities to cover potential short-term liquidity needs and to refinance upcoming maturities. For marginal credit situations, the focus shifts more to free operating cash flow--after deducting the various fixed uses such as working capital investment and capital expenditures--as this measure is more directly related to current debt service capability.

### c) Cash flow from operations (CFO)

241. The measurement and analysis of CFO forms an important part of our ratings assessment, in particular for companies that operate in working-capital-intensive industries or industries in which working capital flows can be volatile. CFO is distinct from FFO as it is a pure measure of cash flow calculated after accounting for the impact on earnings of changes in operating assets and liabilities. CFO is cash flow that is available to finance items such as capital expenditures, repay borrowing, and pay for dividends and share buybacks.

242. In many industries, companies shift their focus to cash flow generation in a downturn. As a result, even though they typically generate less cash from ordinary business activities because of low capacity utilization and relatively low fixed-cost absorption, they may generate cash by reducing inventories and receivables. Therefore, although FFO is likely to be lower in a downturn, the impact on CFO may not be as great. In times of strong growth the opposite will be true, and consistently lower CFO compared to FFO without a corresponding increase in revenue and profitability can indicate an untenable situation.

243. Working capital is a key element of a company's cash flow generation. While there tends to be a need to build up working capital and therefore to consume cash in a growth or expansion phase, changes in working capital can also act as a buffer in case of a downturn. Many companies will sell off inventories and invest a lower amount in raw materials because of weaker business activities, both of which reduce the amount of capital and cash that is tied up in working capital. Therefore, working capital fluctuations can occur both in periods of revenue growth and contraction and analyzing a company's near-term working capital needs is crucial for estimating future cash flow developments.

244. Often, businesses that are capital intensive are not working-capital-intensive: most of the capital commitment is upfront in equipment and machinery, while asset-light businesses may have to invest proportionally more in inventories and receivables. That also affects margins, because capital-intensive businesses tend to have proportionally lower operating expenses (and therefore higher EBITDA margins), while working-capital-intensive businesses usually report lower EBITDA margins. The resulting cash flow volatility can be significant: because all investment is made upfront in a capital-intensive business, there is usually more room to absorb subsequent EBITDA volatility because margins are higher. For example, a capital-intensive company may remain reasonably profitable even if its EBITDA margin declines from 30% to 20%. By contrast, a working-capital-intensive business with a lower EBITDA margin (due to higher operating expenses) of 8% can post a negative EBITDA margin if EBITDA volatility is large.

### d) Free operating cash flow (FOCF)

245. By deducting capital expenditures from CFO, we arrive at FOCF, which can be used as a proxy for a company's cash generated from core operations. We may exclude discretionary capital expenditures for capacity growth from the FOCF calculation, but in practice it is often difficult to discriminate between spending for expansion and replacement. And, while companies have some flexibility to manage their capital budgets to weather down cycles, such flexibility is generally temporary and unsustainable in light of intrinsic requirements of the business. For example, companies can be compelled to increase their investment programs because of strong demand growth or technological changes. Regulated entities (for example, telecommunications companies) might also face significant investment requirements related to their concession contracts (the understanding between a company and the host government that specifies the rules under which the company can operate locally).

246. Positive FOCF is a sign of strength and helpful in distinguishing between two companies with the same FFO. In addition, FOCF is helpful in differentiating between the cash flows generated by more and less capital-intensive companies and industries.

247. In highly capital-intensive industries (where maintenance capital expenditure requirements tend to be high) or in other situations in which companies have little flexibility to postpone capital expenditures, measures such as FFO to debt and debt to EBITDA may provide less valuable insight into relative creditworthiness because they fail to capture potentially meaningful capital expenditures. In such cases, a ratio such as FOCF to debt provides greater analytical insight.

248. A company serving a low-growth or declining market may exhibit relatively strong FOCF because of diminishing fixed and working capital needs. Growth companies, in contrast, exhibit thin or even negative FOCF because of the investment needed to support growth. For the low-growth company, credit analysis weighs the positive, strong current cash flow against the danger that this high level of cash flow might not be sustainable. For the high-growth company,

the opposite is true: weighing the negatives of a current cash deficit against prospects of enhanced cash flow once current investments begin yielding cash benefits. In the latter case, if we view the growth investment as temporary and not likely to lead to increased leverage over the long-term, we'll place greater analytical importance on FFO to debt rather than on FOCF to debt. In any event, we also consider the impact of a company's growth environment in our business risk analysis, specifically in a company's industry risk analysis (see section B).

#### e) Discretionary cash flow (DCF)

249. For corporate issuers primarily rated in the investment-grade universe, DCF to debt can be an important barometer of future cash flow adequacy as it more fully reflects a company's financial policy, including decisions regarding dividend payouts. In addition, share buybacks and potential M&A, both of which can represent very significant uses of cash, are important components in cash flow analysis.

250. The level of dividends depends on a company's financial strategy. Companies with aggressive dividend payout targets might be reluctant to reduce dividends even under some liquidity pressure. In addition, investment-grade companies are less likely to reduce dividend payments following some reversals--although dividends ultimately are discretionary. DCF is the truest reflection of excess cash flow, but it is also the most affected by management decisions and, therefore, does not necessarily reflect the potential cash flow available.

## D. Diversification/Portfolio Effect

### 1. Academic research

251. Academic research recently concluded that, during the global financial crisis of 2007-2009, conglomerates had the advantage over single sector-focused firms because they had better access to the credit markets as a result of their debt co-insurance and used the internal capital markets more efficiently (i.e., their core businesses had stronger cash flows). Debt co-insurance is the view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the crisis. (Source: "Does Diversification Create Value In The Presence Of External Financing Constraints? Evidence From The 2007-2009 Financial Crisis," Venkat Kuppuswamy and Belen Villalonga, Harvard Business School, Aug. 19, 2011.)

252. In addition, fully diversified, focused companies saw more narrow credit default swap spreads from 2004-2010 vs. less diversified firms. This highlighted that lenders were differentiating for risk and providing these companies with easier and cheaper access to capital. (Source: "The Power of Diversified Companies During Crises," The Boston Consulting Group and Leipzig Graduate School of Management, January 2012.)

253. Many rated conglomerates are either country- or region-specific; only a small percentage are truly global. The difference is important when assessing the country and macroeconomic risk factors. Historical measures for each region, based on volatility and correlation, reflect regional trends that are likely to change over time.

## E. Financial Policy

### 1. Controlling shareholders

254. Controlling shareholder(s)--if they exist--exert significant influence over a company's financial risk profile, given their ability to use their direct or indirect control of the company's financial policies for their own benefit. Although the criteria do not associate the presence of controlling shareholder(s) to any predefined negative or positive impact, we assess the potential medium- to long-term implications for a company's credit standing of these strategies. Long-term ownership--such as exists in many family-run businesses--is often accompanied by financial discipline and reluctance to incur aggressive leverage. Conversely, short-term ownership--such as exists in private equity sponsor-owned companies--generally entails financial policies aimed at achieving rapid returns for shareholders typically through aggressive debt leverage.

255. The criteria define controlling shareholder(s) as:

- A private shareholder (an individual or a family) with majority ownership or control of the board of directors;
- A group of shareholders holding joint control over the company's board of directors through a shareholder agreement. The shareholder agreement may be comprehensive in scope or limited only to certain financial aspects; and
- A private equity firm or a group of private equity firms holding at least 40% in a company or with majority control of its board of directors.

256. A company is not considered to have a controlling shareholder if it is publicly listed with more than 50% of voting interest listed or when there is no evidence of a particular shareholder or group of shareholders exerting 'de facto' control over a company.

257. Companies that have as their controlling shareholder governments or government-related entities, infrastructure and asset-management funds, and diversified holding companies and conglomerates are assessed in separate criteria.

### 2. Financial discipline

#### a) Leverage influence from acquisitions

258. Companies may employ more or less acquisitive growth strategies based on industry dynamics, regulatory changes, market opportunities, and other factors. We consider management teams with disciplined, transparent acquisition strategies that are consistent with their financial policy framework as providing a high degree of visibility into the projected evolution of cash flow and credit measures. Our assessment takes into account management's track record in terms of acquisition strategy and the related impact on the company's financial risk profile. Historical evidence of limited management tolerance for significant debt-funded acquisitions provides meaningful support for the view that projected credit ratios would not significantly weaken as a result of the company's acquisition policy. Conversely, management teams that pursue opportunistic acquisition strategies, without well-defined parameters, increase the risks that the company's financial risk profile may deteriorate well beyond our forecasts.

259. Acquisition funding policies and management's track record in this respect also provide meaningful insight in terms of credit ratio stability. In the criteria, we take into account management's willingness and capacity to mobilize all funding resources to restore credit quality, such as issuing equity or disposing of assets, to mitigate the impact of sizable

acquisitions on credit ratios. The financial policy framework and related historical evidence are key considerations in our assessment.

### b) Leverage influence from shareholder remuneration policies

260. A company's approach to rewarding shareholders demonstrates how it balances the interests of its various stakeholders over time. Companies that are consistent and transparent in their shareholder remuneration policies, and exhibit a willingness to adjust shareholder returns to mitigate adverse operating conditions, provide greater support to their long-term credit quality than other companies. Conversely, companies that prioritize cash returns to shareholders in periods of deteriorating economic, operating, or share price performance can significantly undermine long-term credit quality and exacerbate the credit impact of adverse business conditions. In assessing a company's shareholder remuneration policies, the criteria focus on the predictability of shareholder remuneration plans, including how a company builds shareholder expectations, its track record in executing shareholder return policies over time, and how shareholder returns compare with industry peers'.

261. Shareholder remuneration policies that lack transparency or deviate meaningfully from those of industry peers introduce a higher degree of event risk and volatility and will be assessed as less predictable under the criteria. Dividend and capital return policies that function primarily as a means to distribute surplus capital to shareholders based on transparent and stable payout ratios--after satisfying all capital requirements and leverage objectives of the company, and that support stable to improving leverage ratios--are considered the most supportive of long term credit quality.

### c) Leverage influence from plans regarding investment decisions or organic growth strategies

262. The process by which a company identifies, funds, and executes organic growth, such as expansion into new products and/or new markets, can have a significant impact on its long-term credit quality. Companies that have a disciplined, coherent, and manageable organic growth strategy, and have a track record of successful execution are better positioned to continue to attract third-party capital and maintain long-term credit quality. By contrast, companies that allocate significant amounts of capital to numerous, unrelated, large and/or complex projects and often incur material overspending against the original budget can significantly increase their credit risk.

263. The criteria assess whether management's organic growth strategies are transparent, comprehensive, and measurable. We seek to evaluate the company's mid- to long-term growth objectives--including strategic rationales and associated execution risks--as well as the criteria it uses to allocate capital. Effective capital allocation is likely to include guidelines for capital deployment, including minimum return hurdles, competitor activity analysis, and demand forecasting. The company's track record will provide key data for this assessment, including how well it executes large and/or complex projects against initial budgets, cost overruns, and timelines.

## 3. Financial policy framework

### a) Comprehensiveness of financial policy framework

264. Financial policies that are clearly defined, unambiguous, and provide a tight framework around management behavior are the most reliable in determining an issuer's future financial risk profile. We assess as consistent with a supportive assessment, policies that are clear, measurable, and well understood by all key stakeholders. Accordingly, the financial policy framework must include well-defined parameters regarding how the issuer will manage its cash flow protection

strategies and debt leverage profile. This includes at least one key or a combination of financial ratio constraints (such as maximum debt to EBITDA threshold) and the latter must be relevant with respect to the issuer's industry and/or capital structure characteristics.

265. By contrast, the absence of established financial policies, policies that are vague or not quantifiable, or historical evidence of significant and unexpected variation in management's long-term financial targets could contribute to an overall assessment of a non-supportive financial policy.

### b) Transparency of financial policies

266. We assess as supportive financial policy objectives that are transparent and well understood by all key stakeholders and we view them as likely to influence an issuer's financial risk profile over time. Alternatively, financial policies, if they exist, that are not communicated to key stakeholders and/or where there is limited historical evidence to support the company's commitment to these policies, are non-supportive, in our view. We consider the variety of ways in which a company communicates its financial policy objectives, including public disclosures, investor presentation materials, and public commentary.

267. In some cases, however, a company may articulate its financial policy objectives to a limited number of key stakeholders, such as its main creditors or to credit rating agencies. In these situations, a company may still receive a supportive classification if we assess that there is a sufficient track record (more than three years) to demonstrate a commitment to its financial policy objectives.

### c) Achievability and sustainability of financial policies

268. To assess the achievability and sustainability of a company's financial policies, we consider a variety of factors, including the entity's current and historical financial risk profile; the demands of its key stakeholders (including dividend and capital return expectations of equity holders); and the stability of the company's financial policies that we have observed over time. If there is evidence that the company is willing to alter its financial policy framework because of adverse business conditions or growth opportunities (including M&A), this could support an overall assessment of non-supportive.

### 4. Financial policy adjustments--examples

269. Example 1: A moderately leveraged company has just been sold to a new financial sponsor. The financial sponsor has not leveraged the company yet and there is no stated financial policy at the outset. We expect debt leverage to increase upon refinancing, but we are not able to factor it precisely in our forecasts yet.
Likely outcome: FS-6 financial policy assessment, implying that we expect the new owner to implement an aggressive financial policy in the absence of any other evidence.

270. Example 2: A company has two owners—a family owns 75%, a strategic owner holds the remaining 25%. Although the company has provided Standard & Poor's with some guidance on long-term financial objectives, the overall financial policy framework is not sufficiently structured nor disclosed to a sufficient number of stakeholders to qualify for a supportive assessment. Recent history, however, does not provide any evidence of unexpected, aggressive financial transactions and we believe event risk is moderate.
Likely outcome: Neutral financial policy impact, including an assessment of neutral for financial discipline. Although the company's financial framework does not support long-term visibility, historical evidence and stability of management suggest that event risk is not significant. The unsupportive financial framework assessment, however,

prevents the company from qualifying for an overall positive financial policy assessment, should the conditions for positive financial discipline be met.

271. Example 3: A company (not owned by financial sponsors) has stated leverage targets equivalent to a significant financial risk profile assessment. The company continues to make debt-financed acquisitions yet remains within its leverage targets, albeit at the weaker end of these. Our forecasts are essentially built on expectations that excess cash flow will be fully used to fund M&A or, possibly pay share repurchases, but that management will overall remain within its leverage targets.
Likely outcome: Neutral financial policy impact. Although management is fairly aggressive, the company consistently stays within its financial policy targets. We think our forecasts provide a realistic view of the evolution of the company's credit metrics over the next two years. No event risk adjustment is needed.

272. Example 4: A company (not owned by a financial sponsor) has just made a sizable acquisition (consistent with its long-term business strategy) that has brought its credit ratios out of line. Management expressed its commitment to rapidly improve credit ratios back to its long-term ratio targets—representing an acceptable range for the SACP--through asset disposals or a rights issue. We see their disposal plan (or rights issue) as realistic but precise value and timing are uncertain. At the same time, management has a supportive financial policy framework, a positive track record of five years, and assets are viewed as fairly easily tradable.
Likely outcome: Positive financial policy impact. Although forecast credit ratios will remain temporarily depressed, as we cannot fully factor in asset disposals (or rights issue) due to uncertainty on timing/value, or without leaking confidential information, the company's credit risk should benefit from management's positive track record and a satisfactory financial policy framework. The anchor will be better by one notch if management and governance is at least satisfactory and liquidity is at least adequate.

273. Example 5: A company (not owned by a financial sponsor) has very solid financial ratios, providing it with meaningful flexibility for M&A when compared with management's long-term stated financial policy. Also, its stock price performance is somewhat below that of its closest industry peers. Although we have no recent evidence of any aggressive financial policy steps, we fundamentally believe that, over the long-term term, the company will end up using its financial flexibility for the right M&A opportunity, or alternatively return cash to shareholders.
Likely outcome: Negative financial policy impact. Long-term event risk derived from M&A cannot be built into forecasts nor shareholder returns (share buybacks or one-off dividends) be built into forecasts to attempt aligning projected ratios with stated long-term financial policy levels. This is because our forecasts are based on realistic and reasonably predictable assumptions for the medium term. The anchor will be adjusted down, by one notch or more, because of the negative financial policy assessment.

## F. Corporate Criteria Glossary

Anchor: The combination of an issuer's business risk profile assessment and its financial risk profile assessment determine the anchor. Additional rating factors can then modify the anchor to determine the final rating or SACP.

Asset profile: A descriptive way to look at the types and quality of assets that comprise a company (examples can include tangible versus intangible assets, those assets that require large and continuing maintenance, upkeep, or reinvestment, etc.).

Business risk profile: This measure comprises the risk and return potential for a company in the market in which it participates, the country risks within those markets, the competitive climate, and the competitive advantages and disadvantages the company has. The criteria combine the assessments for Corporate Industry and Country Risk Assessment (CICRA), and competitive position to determine a company's business risk profile assessment.

Capital-intensive company: A company exhibiting large ongoing capital spending to sales, or a large amount of depreciation to sales. Examples of capital-intensive sectors include oil production and refining, telecommunications, and transportation sectors such as railways and airlines.

Cash available for debt repayment: Forecast cash available for debt repayment is defined as the net change in cash for the period before debt borrowings and debt repayments. This includes forecast discretionary cash flow adjusted for our expectations of: share buybacks, net of any share issuance, and M&A. Discretionary cash flow is defined as cash flow from operating activities less capital expenditures and total dividends.

Competitive position: Our assessment of a company's: 1) competitive advantage; 2) operating efficiency; 3) scale, scope, and diversity; and 4) profitability.

- Competitive advantage--The strategic positioning and attractiveness to customers of the company's products or services, and the fragility or sustainability of its business model.
- Operating efficiency--The quality and flexibility of the company's asset base and its cost management and structure.
- Scale, scope, and diversity--The concentration or diversification of business activities.
- Profitability--Our assessment of both the company's level of profitability and volatility of profitability.

Competitive Position Group Profile (CPGP): Used to determine the weights to be assigned to the four components of competitive position. While industries are assigned to one of the six profiles, individual companies and industry subsectors can be classified into another CPGP because of unique characteristics. Similarly, national industry risk factors can affect the weighing. The six CPGPs are:

- Services and product focus,
- Product focus/scale driven,
- Capital or asset focus,
- Commodity focus/cost driven,
- Commodity focus/scale driven, and
- National industry and utilities.

Conglomerate: Companies that have at least three distinct business segments, each contributing between 10%-50% of EBITDA or FOCF. Such companies may benefit from the diversification/portfolio effect.

Controlling shareholders: Equity owners who are able to affect decisions of varying effect on operations, leverage, and shareholder reward without necessarily being a majority of shareholders.

Corporate Industry and Country Risk Assessment (CICRA): The result of the combination of an issuer's country risk assessment and industry risk assessment.

Debt co-insurance: The view that the joining-together of two or more firms whose earnings streams are less-than-perfectly correlated reduces the risk of default of the merged firms (i.e., the co-insurance effect) and thereby increases the "debt capacity" or "borrowing ability" of the combined enterprise. These financing alternatives became more valuable during the global financial crisis of 2007-2009.

Financial headroom: Measure of deviation tolerated in financial metrics without moving outside or above a pre-designated band or limit typically found in loan covenants (as in a debt to EBITDA multiple that places a constraint on leverage). Significant headroom would allow for larger deviations.

Financial risk profile: The outcome of decisions that management makes in the context of its business risk profile and its financial risk tolerances. This includes decisions about the manner in which management seeks funding for the company and how it constructs its balance sheet. It also reflects the relationship of the cash flows the organization can achieve, given its business risk profile, to its financial obligations. The criteria use cash flow/leverage analysis to determine a corporate issuer's financial risk profile assessment.

Financial sponsor: An entity that follows an aggressive financial strategy in using debt and debt-like instruments to maximize shareholder returns. Typically, these sponsors dispose of assets within a short to intermediate time frame. Financial sponsors include private equity firms, but not infrastructure and asset-management funds, which maintain longer investment horizons.

Profitability ratio: Commonly measured using return on capital and EBITDA margins but can be measured using sector-specific ratios. Generally calculated based on a five-year average, consisting of two years of historical data, and our projections for the current year and the next two financial years.

Shareholder remuneration policies: Management's stated shareholder reward plans (such as a buyback or dividend amount, or targeted payout ratios).

Stand-alone credit profile (SACP): Standard & Poor's opinion of an issue's or issuer's creditworthiness, in the absence of extraordinary intervention or support from its parent, affiliate, or related government or from a third-party entity such as an insurer.

Transfer and convertibility assessment: Standard & Poor's view of the likelihood of a sovereign restricting nonsovereign access to foreign exchange needed to satisfy the nonsovereign's debt service obligations.

Unconsolidated equity affiliates: Companies in which an issuer has an investment, but which are not consolidated in an issuer's financial statements. Therefore, the earnings and cash flows of the investees are not included in our primary metrics unless dividends are received from the investees.

Upstream/midstream/downstream: Referring to exploration and production, transport and storage, and refining and distributing, respectively, of natural resources and commodities (such as metals, oil, gas, etc.).

Volatility of profitability/SER: We base the volatility of profitability on the standard error of the regression (SER) for a company's historical EBITDA. The SER is a statistical measure that is an estimate of the deviation around a 'best fit' trend line. We combine it with the profitability ratio to determine the final profitability assessment. We only calculate

SER when companies have at least seven years of historical annual data, to ensure that the results are meaningful.

Working-capital-intensive companies: Generally a company with large levels of working capital in relation to its sales in order to meet seasonal swings in working capital. Examples of working-capital-intensive sectors include retail, auto manufacturing, and capital goods.

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

Rating Action Commentary

# Fitch Affirms AEP and Subsidiaries; Outlook Stable

Tue 28 Feb, 2023 - 2:07 PM ET

Fitch Ratings - New York - 28 Feb 2023: Fitch Ratings has affirmed the Long-Term Issuer Default Rating (IDR) and senior unsecured rating for American Electric Power Company, Inc. (AEP) at 'BBB'. Fitch has assigned a 'BBB' rating to AEP's issuance of $850 million 5.625% senior notes due 2033. AEP's Rating Outlook is Stable.

Additionally, Fitch has affirmed the IDRs of AEP's utility operating subsidiaries as follows: Indiana Michigan Power Co. (IMPCo) and Ohio Power Co. (OPCo) at 'A-'; Appalachian Power Co. (APCo) and Public Service Company of Oklahoma (PSO) at 'BBB+'; AEP Texas (AEPTX) at 'BBB', and Kentucky Power Co. (KPCo) and Southwestern Electric Power Co. (SWEPCo) at 'BBB'. The senior unsecured ratings for all of the aforementioned utility operating subsidiaries receive a one-notch uplift relative to their respective IDRs. The Outlooks for all of the utility operating subsidiaries are Stable.

The affirmation of AEP and subsidiaries is based on AEP's low-risk profile as a regulated utility system, its transition of the regulated generation fleet away from coal generation, and ongoing efforts to improve regulated returns. Fitch expects AEP's FFO leverage to average around 5.5x over the forecast period, which Fitch views as consistent with 'BBB' rating. In affirming the rating Fitch expects a balanced use of asset sale proceeds to support credit metrics.

## Key Rating Drivers

AEP

Delayed Kentucky Power Sale: In October 2021, AEP announced it had reached an agreement to sell KPCo to Liberty Utilities (LU; BBB/Stable), the regulated business subsidiary of Algonquin Power & Utilities (APUC; BBB/Stable). The transaction was originally valued at $2.85 billion (including the assumption of $1.3 billion in debt), and was expected to close in 2Q22. In September 2022, the KPCo transaction was amended to remove the condition for a new operating agreement for the jointly owned coal-fired Mitchell power plant, and the transaction price was reduced to $2.646 billion.

The transaction had received approval of the Kentucky Public Service Commission (KPSC), as well as federal clearance under the Hart-Scott-Rodino Act (HSR) and the Committee on Foreign Investment in the United States (CFIUS). The remaining approval required, which was by the Federal Energy Regulatory Commission (FERC) was denied on Dec. 15, 2022. The companies have filed a new FERC merger application. The delay in FERC approval may require the parties to extend the current contractual deadline of April 26, 2023. Additionally, HSR clearance expired one year after approval, and was refiled in February 2023 with an outcome expected in March 2023. Fitch assumes that the sale will ultimately be consummated. AEP plans to use the $1.2 billion after tax cash proceeds from the sale of KPCo to offset previously forecast equity needs.

Contracted Renewable Sale: AEP announced on Feb. 22, 2023 that it has reached an agreement to sell 100% of its 1,365 MW contracted renewable portfolio to a non-affiliated party. The transaction will require approval by FERC, CFIUS, among other applicable competition laws and is expected to close in 2Q23. The company expects $1.2 billion in cash proceeds from the transaction, which it has publicly stated will be used for reduction of short-term debt.

Large Deferred Fuel Balances: Many of AEP's subsidiaries have experienced significant increases in deferred fuel and purchased power costs. The increases are largely the result of the high natural gas prices experienced at times over the last two years and the inability to pass along the costs on a timely basis. As of Dec. 31, 2022, the total deferred fuel regulatory asset for all of the AEP subsidiaries was almost $1.7 billion, which is a $1.1 billion increase from the balance as of Dec. 31, 2021.

The AEP subsidiaries are working with their state commissions to reach resolutions for recovery of the amounts while mitigating customer bill impact. The resolutions may include elongated recovery times or securitization. Additionally, in some jurisdictions, fuel recovery clauses are being modified to allow for more timely pass through of costs to prevent the build up of large deferred balances. Fitch considers the deferrals to be timing differences and excludes the cash flow impact from FFO, but includes the debt impact in FFO leverage. Fitch's treatment of the deferred balances anticipates favorable regulatory outcomes for recovery thereof.

Large Capex Program: AEP's 2023-2025 capex plan of $25.5 billion is 11% larger than the previous three-year plan and the company's five-year plan of $40 billion is a 4.4% increase from the 2022-2026 plan. The company expects a 7.6% average annual rate base growth from 2023-2027. Transmission assets, the majority of which are favorably regulated by FERC, account for 38% of the planned expenditures. Distribution spending comprises 27% and regulated renewables 22%. Management expects that nearly 85% of the company's capital plan will be recoverable under reduced lag mechanisms.

Over recent years, the company has increasingly debt financed its capex, leading to higher leverage. Fitch expects AEP's FFO leverage to average around 5.5x over the forecast period, which is within the 5.8x downgrade rating threshold. Fitch estimates AEP's parent-level debt will account for approximately 20% of its total debt load over the forecast period, versus 25%-30% at most of its peers. In addition to the KPCO sale and divestiture of contracted renewables portfolio, AEP has initiated strategic review of its retail energy supplier, AEP Energy.

Balanced Regulatory Construct: Fitch views the state regulatory constructs within AEP's 11-state (soon to be 10-state) service territory as balanced. AEP's large footprint, allows it to benefit from regulatory diversity with no operating company comprising more than 20% of the consolidated rate base. Authorized state ROEs are close to the industry average in most jurisdictions and include provisions to mitigate commodity and environmental regulation risks. AEP's transmission entities, most of which are subsidiaries of AEP Transco, operate under a tariff approved by the FERC. Fitch expects AEP's consolidated earned ROE to average around 9.0% in 2023-2025. The company's consolidated earned ROE of LTM Dec. 31, 2022 was 9.1%.

Improving Asset Base: As a result of the companies' focus on transmission investment, AEP Transco is now AEP's largest subsidiary in terms of equity investment and EBITDA. The favorably FERC-regulated entity accounts for almost 20% of AEP's consolidated EBITDA. AEP Transco's earned ROE of LTM Dec. 31, 2022 was 10.6%. AEP plans to continue reducing its reliance on coal-fired generation and increase renewable capacity through acquisition of rate-based assets and power purchase agreements (PPAs). The recently enacted Inflation Reduction Act will further accelerate the asset transition that was already underway.

Parent-Subsidiary Rating Linkage: There is parent subsidiary linkage between AEP and all of its rated subsidiaries. Fitch considers AEP Transmission Company LLC (A-/Stable), Appalachian Power Co. (BBB+/Stable), Indiana Michigan Power Co. (A-/Stable), Ohio Power Co. (A-/Stable) and Public Service Company of Oklahoma (BBB+/Stable) to have standalone credit profiles (SCP) stronger than AEP. As such, Fitch has followed the stronger subsidiary path and emphasized the subsidiaries' status as regulated entities. Legal ring fencing is porous given the general protections afforded by economic regulation, and access and control are also porous.

AEP centrally manages the treasury function for all of its entities and is the sole source of equity; however, each subsidiary issues its own long-term debt. AEP Texas Inc. (BBB/Stable) and Southwestern Electric Power Company (BBB/Stable) are rated the same as AEP, but if their SCPs were to be stronger than AEP the two subsidiaries would follow the same linkage consideration as outlined above. Due to the aforementioned linkage considerations, Fitch will limit the difference between AEP and any of its higher rated regulated subsidiaries to two notches.

KPCo has a weaker SCP than AEP, and Fitch has followed the stronger parent path. Legal incentives are weak as AEP does not guarantee KPCo debt. AEP has announced the sale of KPCo, thereby rendering strategic incentives as weak. Operational incentives are scored as medium given the joint-ownership of the Mitchell plant, which will require the approval of a new ownership and operational agreement to complete the sale. As a result of the aforementioned assessment, Fitch has applied a one-notch uplift to KPCo's ratings.

AEPTX

Low-Risk Business Profile: AEPTX owns and operates regulated electricity transmission and distribution (T&D) networks located in the Electric Reliability Council of Texas (ERCOT). The Public Utility Commission of Texas (PUCT) sets rates on a cost-of-service basis with the opportunity for capital recovery outside of base rate proceedings through annual or semi-annual clause mechanisms. AEPTX does not have direct exposure to commodity prices. AEPTX had non-material impact from the market disruptions due to the February 2021 winter storm.

2020 Base Rate Proceeding: AEPTX concluded in April 2020, as per the settlement, its first base rate proceeding since 2006. The approved settlement resulted in a $40 million revenue decrease based on a 9.4% ROE, 42.5% hypothetical equity capital structure and 2018 test year. The lower equity capitalization further pressures metrics already affected by significant capex spend.

In addition to traditional rate case issues, the somewhat contentious proceedings included a return of excess federal income taxes collected, due to the Tax Cuts and Jobs Act of 2017 (TCJA), implementation of ringfencing measures, inclusion in base rates of amounts previously recovered under rate riders and consolidation of rate structures of AEPTX's two predecessor entities. AEPTX is required to file its next rate case no later than April 5, 2024.

Energy Industry Exposure: AEPTX's service territory encompasses the Eagle Ford and Permian shale gas basins, which continue to experience strong growth. AEPTX's weather-normalized kWh sales increased 2.5% in 2021 versus 2020. The company forecasts total weather-normalized kWh sales to increase by 7.8% in 2022.

Pressured Credit Metrics: As a result of AEPTX's lower equity capitalization and continued regulatory lag due to the service territory's high growth, AEPTX's FFO leverage has declined significantly; however, is still expected to exceed 6.0x over most of the forecast period. The company's 2023-2025 capex forecast of $4.1 billion is approximately 18% higher versus the prior three-year forecast. The company's earned ROE as of LTM Dec. 31, 2022 was 8.2%. Fitch expects parent AEP will only make equity infusions to maintain the regulatory capital structure as authorized, which will result in credit metrics lower than most 'BBB' rated utilities. However, Fitch considers the low risk nature of the T&D companies in Texas an offsetting factor to support the current rating.

APCo

Large Deferred Fuel Balances: APCo has experienced significant increases in deferred fuel and purchased power costs in both its Virginia and West Virginia jurisdictions. The increases are the result of the high natural gas prices experienced over parts of the last two years and the inability to pass along the costs on a timely basis. As of Dec. 31, 2022, APCO's Virginia deferred fuel regulatory asset is $407.9 million and West Virginia's is $288.5 million. In Virginia, APCo is awaiting an order on its proposal to recovery its deferred fuel balance over two years. The West Virginia Public Service Commission (WVPSC) issued an order in in February 2023 stating that the commission will not grant additional rate increases for fuel costs until the WVPSC staff completes a prudency review. On the positive side, WV is considering securitization as a way of lowering the bill impact of fuel cost recovery.

Virginia Utility Regulation Reform: Fitch considers Virginia utility regulation to generally be supportive of credit quality; however, Virginia has a history of codifying regulation with legislation. The state legislature recently passed legislation altering the current triennial review period to biennial. Additionally, the legislation authorizes the use of securitization for deferred fuel and purchased power costs. The governor has until March 27, 2023 to sign the legislation. Fitch considers the shorter time frame between rate cases as beneficial to APCo, given on going regulatory lag. As of LTM Dec. 31, 2022, APCo's earned ROE improved to 8.7% from 7.9% at LTM Dec. 31, 2021, but remains less than its authorized ROE.

Virginia Triennial Review: APCo received an order on Nov. 24, 2020 in its first legislatively mandated triennial review, which covers the 2017-2019 earnings test years. The Virginia State Corporation Commission (VSCC) order resulted in no gross revenue increase, and a net revenue decrease of $25.5 million, based upon 9.2% ROE and 50% equity capitalization. APCo challenged a certain aspect of the order, which ultimately resulted in an order on remand from the VSCC with a revised net revenue increase of $37 million. The company is expected to submit its next triennial review in March 2023 for the period 2020-2022.

In April 2020, the governor of Virginia signed the Virginia Clean Economy Act (VCEA) into law, which replaced the state's voluntary renewable energy portfolio with a mandatory program. The legislation mandates fossil-fuel plant retirements, deems renewable investments to be in the public interest and eligible for rider recovery, and increases thresholds for energy efficiency. Fitch expects APCo's capex to remain elevated, as it complies with VCEA's provisions.

Improving West Virginia Regulation: Fitch has considered the regulatory compact in West Virginia to be restrictive, owing to a history of lower than average ROEs and historic test years that exacerbate regulatory lag. However, Fitch views recent rate decisions in the state as more balanced from a credit perspective, including settled outcomes and use of riders for certain costs. The West Virginia Public Service Commission (WVPSC) approved the settlement agreement on Feb. 27, 2019, concluding APCo's first rate case in its West Virginia jurisdiction in over five years.

The settlement includes an annual base rate increase of $44 million, including $8 million for affiliate Wheeling Power Company (WPCo; not rated) based on a 9.75% return on common equity, 50.16% equity capitalization and $4.0 billion combined rate base. In June 2021, the WVPSC issued an order approving a recovery mechanism that will allow APCo, along with WPCo to recover investment expenditures made between rate cases. Fitch believes such investment recovery mechanisms are beneficial to reducing regulatory lag and supporting credit quality.

Reliance on Coal Shifting: APCo's approximately 64% coal generation, including PPAs, is the highest of the AEP integrated companies. As a result, the company is exposed to potentially higher expenditures as increasingly stringent environmental regulations are implemented. APCo continues to pursue clean energy resources. The company owns or has PPAs in place for approximately 21% of its generation mix.

Significant Capex Program. Fitch expects APCo to expand its rate base by almost 6% annually, with expenditures of $4.6 billion in 2023-2025 and five-year total of $6.7 billion. Spending will be focused on capacity expansion, reliability investments and fleet transformation. Over the five-year capital plan, APCo plans to invest $3.7 billion in transmission and distribution assets, and $1.8 billion in renewables.

Weaker Credit Metrics: Fitch expects that APCO's FFO leverage will be near its 4.8x downgrade metric over the near-term forecast period, but improve in the later years as the company's large deferred fuel and purchased power balances are recovered. Fitch considers the deferrals to be timing differences and excludes the cash flow impact from FFO, but includes the debt impact in

FFO leverage, which given APCo's large balances is significant. Fitch's treatment of the deferred balances anticipates favorable regulatory outcomes for recovery thereof.

IMPCo

Supportive Regulation: Fitch believes the regulatory regimes in Indiana (80% of rate base) and Michigan (20% of rate base) are supportive. In addition to slightly above average ROEs, both states utilize recovery riders for environmental upgrades, fuel costs, energy-efficiency programs and other costs.

In November 2021, a settlement was filed with Indiana Utility Regulatory Commission (IURC) in IMPCo's Indiana rate case, which was approved in February 2022. The agreement included a $61 million base rate increase based upon a 9.7% ROE. The revenue increase does not reflect the removal of $141 million of annual expenses for the Rockport power plant, for which IMPCo terminated the lease in December 2022. In IMPCo's smaller Michigan jurisdiction, the Michigan Public Service Commission (MPSC) authorized a $30 million net rate increase effective February 2020. The rate increase was based on a 9.86% ROE, 46.56% equity capitalization, 2020 forecast test year.

Reliance on Coal Shifting: IMPCo's approximately 46% coal generation, including PPAs, is the third-highest of the AEP integrated companies. IMPCo, along with AEGCo is a participant in the Rockport power plant, which consists of two 1,300MW coal-fired units. IMPCo is a 50% co-owner of Unit 1 and a 50% lessee of Unit 2, which was sold into a sale-leaseback transaction in 1989. IMPCo and AEGCo reached an agreement with the owner trustee on April 20, 2021 to buy out 100% of the equity interest in Rockport Unit 2 for $115 million. The transaction is expected to close in December 2022 and will allow for the flexibility to close both Rockport units by 2028, if not earlier.

IMPCo owns the 2,288MW D.C. Cook Nuclear Plant (Cook), which accounts for approximately 44% of the company's generation capacity and is the only nuclear asset in the AEP system. While Fitch considers nuclear generation to have higher operating risk, Cook has operated with a 90%-capacity factor over the last several years, roughly in line with the industry average, and is an important component of AEP's continued transition to a low-carbon environment.

Capex Program: Fitch expects IMPCo to expand its rate base by approximately 6% annually, with expenditures of $2.1 billion in 2023-2025 and $3.6 billion 2023-2027. Over the five-year capital plan, IMPCo plans to invest $347 million for the life extension of Cook, $1.6 billion in transmission and distribution assets, and $1.2 billion in renewables. About 70% of nuclear-related expenditures are attributable to Indiana, and recoverable almost contemporaneously through a rider mechanism.

Improved Credit Metrics: As a result of adequate rate relief, including the ability to utilize a forecast test year, IMPCo's credit metrics remained stable despite significant capex. IMPCo's FFO leverage is expected to be in the range of 3.5x-4.0x, which is consistent with an 'A-' integrated utility.

KPCo

FERC Approval Application Refiled: After initially being denied on Dec. 15, 2022, the parties to KPCo transaction have filed a new FERC merger application, requesting expedited treatment. FERC is allowing a condensed 45-day comment period. The delay in FERC approval may require the parties to extend the current contractual deadline of April 26, 2023. The merger has received clearance from CFIUS and under HSR. However, HSR clearance expired one year after approval, and was refiled in in February 2023 with an outcome expected in March 2023.

Constructive Regulatory Environment: Despite Kentucky Public Service Commission's previously stated concerns about KPCo's capex spending, Fitch views the regulatory compact in Kentucky as generally constructive. A variety of cost recovery mechanisms, including fuel, purchased power, environmental compliance and infrastructure replacement clauses are in place that mitigate the impact of regulatory lag. On Jan. 13, 2021, the KPSC granted KPCo a revenue increase of $52.4 million effective Jan. 14, 2021. The rate increase was based on a 9.30% ROE and 43.25% equity capitalization and a March 31, 2020 test year.

Challenged Service Territory: KPCo's service area is primarily driven by coal mining, which has seen significant contraction in recent years. KPCo's residential customer count has declined about 6% over the last decade, while large commercial and industrial customer numbers have declined almost 20%. Growth in oil and gas extraction mitigates some of the effects of the secular decline in the coal industry. However, Fitch remains concerned that lower sales volumes will continue to pressure metrics and earned returns in the medium term.

Weaker Credit Metrics: KPCo's credit metrics have weakened significantly over the past couple years due to capex, a prior rate freeze, effects of the coronavirus and continued service territory weakness. KPCo has been a perennially under earning asset, with 5.3% earned ROE as of LTM Dec. 31, 2022. Fitch expects that new ownership will likely trim KPCo's capex budget, which was $579 million in 2021-2023, a 5% increase from the prior three years. Additionally, KPCo's FFO leverage is expected to improve in 2023 with the expiration of Rockport PPA. Lower capex spending would benefit KPCo's credit metrics.

OPCo

Low-Risk Business Profile: OPCo owns and operates regulated electricity transmission and distribution networks in Ohio under cost of service-based regulatory frameworks. The company is regulated by the Public Utilities Commission of Ohio (PUCO) and FERC. Fitch estimates that approximately 65%-70% of the company's rate base is regulated by PUCO and approximately 30%-35% by FERC. The company has minimal direct exposure to commodity prices. OPCo is a 20% participant in Ohio Valley Electric Corporation (OVEC; BBB-/Stable) and currently recovers OVEC costs via a non-bypassable charge allocated to all electric distribution utilities in the state as per Ohio House Bill (H.B.) 6. Prior to the enactment of H.B. 6, OPCo recovered OVEC costs through a PUCO-approved PPA rider.

Supportive Regulatory Construct: The majority of OPCo's revenues are derived from rates established by PUCO under a multiyear electric security plan (ESP). OPCo reached a settlement in 2018 that was approved by the PUCO extending the current ESP until 2024. As required, the company filed a base rate case on June 1, 2020 to roll existing rider amounts into base rates. The net increase request was $41.0 million after giving effect to rider adjustments, based upon a 10.15% ROE and 54.43% equity capitalization.

The PUCO approved a settlement on Nov. 17, 2021 which resulted in a minimal change to current rates. The settlement provides for an increase in the residential monthly customer charge to $10.00 from $8.40, discontinues revenue decoupling, and continues the distribution investment rider subject to specified annual revenue caps. The company filed an application in January 2023 for an ESP covering June 2024 through May 2030. This is the company's fifth ESP filing. Fitch expects a continuation of supportive regulation as it pertains to OPCo. The company's earned ROE as of LTM Dec. 31, 2022 was 9.7% and is consistently among the highest of AEP's subsidiaries.

Capex Program: OPCo's capex budget continues to increase due to customer growth and spending to improve grid reliability. Fitch expects the company to expand its rate base by about 7% annually 2020-2027 with expenditures of $2.9 billion in 2023-2025, which is a 20% increase than the prior three-year forecast.

Improving Credit Metrics: After a period of weaker credit metrics, OPCo's FFO leverage is expected to improve in 2023 to just at or slightly better than its downgrade threshold of 4.5x. Fitch expects OCPo will remain within its downgrade metrics, assuming continuation of supportive regulation and limited upstreaming of dividends. OPCo's weaker credit metrics over the last few years has been the result of significant capex, the flow back of excess deferred taxes, and in part, AEP's capital allocation decisions.

PSO

Recent Rate Case Filing: PSO filed its current rate case on Nov. 22, 2022. The company is requesting a net revenue increase of $103 based upon a 10.40% ROE and 54.62% adjusted equity capitalization. Among the items in the multi-faceted case, PSO seeks to roll the remaining North Central Wind assets from rider recovery into base rates as specified in a prior settlement. To reduce regulatory lag, PSO has requested several new or updated regulatory constructs, including a proposed pilot formula-based rate, more frequent resets to the fuel adjustment clause, changes to the Southwest Power Pool Transmission Cost tariff, and an updated distribution and safety rider, among other items.

As a result of regulatory lag, PSO's earned ROE for LTM Dec. 31, 2022 was only 7.1%. Rate cases in Oklahoma are adjudicated in 180 days. Fitch's rating on PSO is premised upon a constructive rate outcome. PSO's last rate case was resolved via settlement, resulting in a $51 million net annual revenue increase based upon 9.4% ROE and 53% equity capitalization.

Winter Storm Uri: PSO received $687 million in proceeds in September 2022 from the Oklahoma Development Finance Authority (ODFA). The ODFA issued securitization bonds for the purpose of reimbursing PSO for approximately $670 million of increased natural gas and purchase power expense as a result of Winter Storm Uri in February 2021. PSO had originally funded the additional expense with approximately $500 million in capital contributions from parent AEP and the remaining amount with debt. Fitch considers under or over collection of deferred fuel and purchased power costs to be a timing difference and as such excludes the amounts from FFO; however, includes the additional debt in its FFO calculation. The receipt of ODFA funds is expected to improve PSO's leverage metrics.

Favorable Generation Mix: PSO is the least coal-exposed of the AEP integrated utilities, with coal-fired generation accounting for only 8.0% of generating and capacity mix. The company owns 4,380 MW of generating capacity and has long-term PPAs on another 1,397 MW. The company continues to add renewable resources and has requested that the OCC make a determination of need and cost recovery for the purchase of three solar and three wind facilities totaling 995 MW.

Additionally, PSO is asking that that a renewable resources rider be put in place until cost recovery can be established in base rates. The total project costs are expected to be approximately $2.47 billion. The impact to rate payers will be greatly reduced by the elimination of fuel expense and ability to generate approximately $1 billion in production tax credits over the life of the assets as a result of the Inflation Reduction Act.

Capex Program: PSO's capex budget continues to increase significantly as it adds new renewable resources and improves grid reliability. Fitch expects the company to expand its rate base by about 13% annually 2020-2027 with expenditures of $3.2 billion in 2023-2025.

Pressured Credit Metrics: PSO's ongoing capex program coupled with regulatory lag has resulted in higher leverage metrics. In order to maintain current ratings, Fitch will look for the reasonable regulatory outcomes in the company's current rate proceedings. Additionally, Fitch expects AEP to manage its capital allocation policy as it pertains to PSO to support the subsidiary's authorized regulatory capital structure. PSO's FFO leverage is expected to improve in 2023 to just at or slightly better than its downgrade threshold of 4.8x.

SWEPCo

Mixed Regulatory Environment: SWEPCo operates in three state jurisdictions, Louisiana (approximately 38% of rate base), Texas (approximately 36% of rate base) and Arkansas (approximately 20% of rate base), as well as FERC (approximately 6% of rate base). Fitch views the regulatory construct for integrated utilities in Louisiana as balanced, while Texas and Arkansas are more challenging. SWEPCo's earned ROE was 8.2% as of the LTM ended Dec. 31, 2021, behind AEP's consolidated earned ROE of 9.1% for the same period, but an improvement from the company's 6.8% earned ROE for LTM ended Dec. 31, 2019. The company's low ROE reflects the ongoing lack of recovery of the Arkansas portion of the Turk coal plant, which accounts for approximately 110bps of ROE drag.

Recent Rate Case Activity: Fitch expects SWEPCo to continue to pursue rate relief as required in its jurisdictions. Constructive outcomes, including ability to earn a regulated return on the remaining Turk plant, could result in improved credit metrics. In January 2022, the PUCT issued a final order in SWEPCo's Texas jurisdiction approving an annual net revenue increase of $23 million based upon 9.25% ROE and 49.4% equity capitalization. The company supported a net revenue increase of $73 million based upon 10.35% ROE and 49.4% equity capitalization.

In Louisiana, the Louisiana Public Service Commission (LPSC) approved a settlement providing for an annual net revenue increase of $27 million based upon 9.5% ROE and 51% equity capitalization. The company's supported a net revenue increase of $73 million based upon 10.35% ROE and 51% equity capitalization. Importantly, the resolution of the Louisiana base rate case will allow SWEPCo to reactive the formula rate plan for the jurisdiction.

SWEPCo received a final order in Arkansas in May 2022, approving $28 million net revenue increase based upon a 9.5% ROE and 45% equity capitalization. The company originally requested a net revenue increase of $56 million based upon 10.35% ROE and 51.3% equity capitalization. In September 2022, SWEPCo made an initial filing requesting the remaining 88 MW Arkansas jurisdictional share of the Turk Plant be put into rates.

Revised Fuel Cost Recovery Mechanisms: Over the last two years, severe winter storms and volatile commodity prices have resulted in large deferrals for fuel and purchased power expenses. Winter Storm URI in February 2021 resulted in deferred regulatory assets of $489 million related to natural gas fuel expense and electricity purchases from Feb. 9, 2021 to Feb. 20, 2021. SWEPCo has received rate orders in all three of its jurisdictions providing for recovery of the balance over a five or six year period depending on the jurisdiction and with with varying carrying costs. Separately, SWEPCo has been allowed to make adjustments in certain cases in Arkansas and Texas to the existing fuel cost mechanisms to allow for expedited recovery and/or lessen impact on customer bills related to deferred fuel and purchased power amounts.

Increased Capex Program: SWEPCo's capex budget continues to increase significantly as it adds new renewable resources and improves grid reliability. Fitch expects the company to expand its rate base by about 11% annually through 2020-2027 with expenditures of $4.3 billion in 2023-2025. Approximately 88% of SWEPCo's projected capex is expected to be allocated to wires and renewables. The company continues to add renewable resources and has requests in all three of its jurisdictions to add 999 MW of additional wind and solar resources in the amount of $2.2 billion. Decisions from the three state commissions are expected later this year.

Opportunity for improved Credit Metrics: After a period of limited rate relief, Fitch expects SWEPCo's credit metrics to improve despite the 25% increase in the company's capex program versus the previous forecast. The inclusion of rate based North Central Wind provides SWEPCo with additional cash flow and reduced the company's reliance on coal generation. Additionally, the projects were funded with a significant equity component that helped to alleviate the pressure on credit metrics from the large expenditure program. Assuming constructive rate case outcomes, Fitch expects that SWEPCo will stay well within Fitch's stated FFO leverage downgrade threshold of 5.5x over the forecast period.

## Derivation Summary

AEP compares favorably with other 'BBB' rated utility parent companies -- Emera Incorporated (Emera; BBB/Stable), CenterPoint Energy (CNP; BBB/Stable), CMS Energy Corp. (CMS;

BBB/Stable) and DTE Energy (DTE; BBB/Stable). All companies derive approximately 90%-95% of EBITDA from regulated assets. AEP is the largest of the aforementioned companies and has the most geographically diverse asset mix in the U.S., operating in 11 (soon to be 10) states; however, Emera also operates in Canada.

Fitch expects AEP's FFO leverage to average around 5.5x over the forecast period depending on the cadence of rate relief. AEPs FFO leverage is weaker than DTE's range of 5.1x-5.5x, CMS's 4.9x-5.0x and CNP's low 5x. Emera is expected to be more levered with FFO leverage at approximately 6.0x. AEP's parent level debt is expected to be approximately 20% over the forecast period. CNP, CMS and DTE parent level debt is expected to be 25%-30%. Emera's parent level debt is expected to be higher at 41%.

## Key Assumptions

Fitch's Key Assumptions Within the Rating Case for the Issuer:

--Consolidated capital expenditures of $25.5 billion over 2023-2025;

--Sale of KPCo competed 2Q23, after tax proceeds of approximately $1.2 billion used to offset equity needs;

--Sale of unregulated contracted renewables portfolio completed in 2Q23 with $1.2 billion cash proceeds used for short term debt reduction;

--Common dividends of $1.7 billion in 2023, $1.9 billion in 2024, $2.1 billion in 2025 as per managements publicly stated forecast;

--Equity Issuances of $100 million in 2023, $600 million in 2024 and $700 million in 2025 as per managements publicly stated forecast;

--Conversion of $850 million equity units in 2023;

--Constructive resolutions to base rate filings over the forecast period;

--Recovery of deferred fuel and purchased power expenses with minimal disallowances.

## RATING SENSITIVITIES

AEP

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Sustained FFO leverage at or below 4.8x;

--Continued balanced jurisdictional rate regulation across AEP's service territory;

--Continued strategic focus on relatively low risk utility and transmission businesses.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Sustained FFO leverage exceeding 5.8x on a sustained basis;

--Renewed emphasis on non-regulated or uncontracted investments;

--Significant unexpected regulatory developments at any of the regulated operating companies.

AEPTX

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Sustained FFO leverage at or below 5.0x;

--Continued balanced jurisdictional rate regulation.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Sustained FFO leverage exceeding 6.5x on a sustained basis;

--Unexpected regulatory development.

APCo, PSO

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Sustained FFO leverage at or below 4.0x;

--Continued balanced jurisdictional rate regulation.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Sustained FFO leverage exceeding 4.8x on a sustained basis;

--Unexpected regulatory development.

KPCo, SWEPCo

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Sustained FFO leverage at or below 4.5x;

--Continued balanced jurisdictional rate regulation.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Sustained FFO leverage exceeding 5.5x on a sustained basis;

--Unexpected regulatory development.

IMPCo, OPCo

Factors that could, individually or collectively, lead to positive rating action/upgrade:

--Sustained FFO leverage at or below 3.5x and an upgrade of AEP;

--Continued balanced jurisdictional rate regulation.

Factors that could, individually or collectively, lead to negative rating action/downgrade:

--Sustained FFO leverage exceeding 4.5x on a sustained basis;

--A downgrade of one notch or more at AEP;

--Unexpected regulatory development.

## Best/Worst Case Rating Scenario

International scale credit ratings of Non-Financial Corporate issuers have a best-case rating upgrade scenario (defined as the 99th percentile of rating transitions, measured in a positive direction) of three notches over a three-year rating horizon; and a worst-case rating downgrade scenario (defined as the 99th percentile of rating transitions, measured in a negative direction) of four notches over three years. The complete span of best- and worst-case scenario credit ratings for all rating categories ranges from 'AAA' to 'D'. Best- and worst-case scenario credit ratings are based on historical performance. For more information about the methodology used to determine sector-specific best- and worst-case scenario credit ratings, visit https://www.fitchratings.com/site/re/10111579.

## Liquidity and Debt Structure

Adequate Liquidity: AEP has a $4.0 billion committed revolving credit facility maturing in March 2027 and a $1 billion committed facility maturing in March 2024, both of which serve as a backstop for AEP's CP program and LOC. AEP must maintain a ratio of debt/total capitalization that does not exceed 67.5%, under the covenants to its credit agreement. This contractually defined percentage was 59.1% as of Sept. 30, 2022. As of Dec. 31, 2022, AEP had $2.138 billion total available on its revolving credit facilities (giving effect for CP issuance) and cash of $509 million. AEP has parent level corporate maturities as follows: $1.900 billion in 2023, $1.104 billion in 2024 and $450 million in 2025.

AEP has $850 million of equity units issued in 2020 for which Fitch does not give equity credit. The 2020 units will be remarketed in 2023. As part of the remarketing of the equity units, the interest rate will reset at the then current market rate and forward equity purchase contract associated with the units will be settled with the issuance of equity. If the remarketing is unsuccessful, investors have the right to put their notes to AEP at a price equal to the principal. Fitch assumes a successful remarketing for the equity units.

AEP's regulated subsidiaries use a pool of corporate borrowing to meet short-term funding needs. The money pool operates according to regulators' approved terms and conditions, and includes maximum authorized borrowing limits for individual companies.

## Issuer Profile

AEP is a utility holding company of regulated electric utility subsidiaries serving portions of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Additionally, the company has significant investments in FERC regulated transmission assets.

## Summary of Financial Adjustments

As of Dec. 31, 2022, Fitch has made the following adjustments:

--$491.6 million of securitized debt has been removed from Fitch's AEP consolidated debt calculation;

--$317.4 million of securitized debt has been removed from Fitch's AEPTX debt calculation;

--$174.2 million of securitized debt has been removed from Fitch's APCo debt calculation.

AEP debt is adjusted by assigning 50% equity credit to AEP's $750 million 3.875% Fixed-to-Fixed Reset Rate Junior Subordinated Debentures due 2062.

## REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

## ESG Considerations

Unless otherwise disclosed in this section, the highest level of ESG credit relevance is a score of '3'. This means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. For more information on Fitch's ESG Relevance Scores, visit www.fitchratings.com/esg.

RATING ACTIONS

Entity / Debt
Rating
Prior
American Electric Power Company, Inc.
LT IDR
BBB
Affirmed
BBB

- senior unsecured

LT
BBB
Affirmed
BBB

- senior unsecured

LT
BBB
New Rating

- junior subordinated

LT
BB+
Affirmed
BB+

- USD 750 mln Variable bond/note 15-Feb-2062 025537AU5

LT
BB+
Affirmed
BB+

- junior subordinated

LT
BBB-
Affirmed
BBB-

- USD 805 mln 2.031% bond/note 15-Mar-2024 025537AK7

LT
BBB-
Affirmed
BBB-
AEP Texas Inc.
LT IDR
BBB
Affirmed
BBB

- senior unsecured

LT
BBB+
Affirmed
BBB+
Appalachian Power Company
LT IDR
BBB+
Affirmed
BBB+
Page
of 3

VIEW ADDITIONAL RATING DETAILS

Additional information is available on www.fitchratings.com

## PARTICIPATION STATUS

The rated entity (and/or its agents) or, in the case of structured finance, one or more of the transaction parties participated in the rating process except that the following issuer(s), if any, did not participate in the rating process, or provide additional information, beyond the issuer's available public disclosure.

## APPLICABLE CRITERIA

- Corporate Hybrids Treatment and Notching Criteria (pub. 12 Nov 2020)
- Corporates Recovery Ratings and Instrument Ratings Criteria - Effective from 9 April 2021 to 13 October 2023 (pub. 09 Apr 2021) (including rating assumption sensitivity)
- Parent and Subsidiary Linkage Rating Criteria - Effective from 1 December 2021 to 16 June 2023 (pub. 01 Dec 2021)
- Sector Navigators: Addendum to the Corporate Rating Criteria - Effective from 28 October 2022 to 12 May 2023 (pub. 28 Oct 2022)
- Corporate Rating Criteria - Effective from 28 October 2022 to 3 November 2023 (pub. 28 Oct 2022) (including rating assumption sensitivity)

## APPLICABLE MODELS

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

- Corporate Monitoring & Forecasting Model (COMFORT Model), v8.1.0 (1)

## ADDITIONAL DISCLOSURES

- Dodd-Frank Rating Information Disclosure Form
- Solicitation Status
- Endorsement Policy

## ENDORSEMENT STATUS

| | |
|---|---|
| AEP Texas Inc. | EU Endorsed, UK Endorsed |
| American Electric Power Company, Inc. | EU Endorsed, UK Endorsed |
| Appalachian Power Company | EU Endorsed, UK Endorsed |
| Indiana Michigan Power Company | EU Endorsed, UK Endorsed |
| Kentucky Power Company | EU Endorsed, UK Endorsed |
| Ohio Power Company | EU Endorsed, UK Endorsed |
| Public Service Company of Oklahoma | EU Endorsed, UK Endorsed |
| Southwestern Electric Power Company | EU Endorsed, UK Endorsed |

## DISCLAIMER & DISCLOSURES

All Fitch Ratings (Fitch) credit ratings are subject to certain limitations and disclaimers. Please read these limitations and disclaimers by following this link: https://www.fitchratings.com/understandingcreditratings. In addition, the following

Read More

### Solicitation Status

The ratings above were solicited and assigned or maintained by Fitch at the request of the rated entity/issuer or a related third party. Any exceptions follow below.

### Endorsement Policy

Fitch's international credit ratings produced outside the EU or the UK, as the case may be, are endorsed for use by regulated entities within the EU or the UK, respectively, for regulatory purposes, pursuant to the terms of the EU CRA Regulation or the UK Credit Rating Agencies (Amendment etc.) (EU Exit) Regulations 2019, as the case may be. Fitch's approach to endorsement in the EU and the UK can be found on Fitch's Regulatory Affairs page on Fitch's website. The endorsement status of international credit ratings is provided within the entity summary page for each rated entity and in the transaction detail pages for structured finance transactions on the Fitch website. These disclosures are updated on a daily basis.

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_18** | Provide the dates of each Major Event Day (MED) for the years 2021 through 2023. Indicate if deferral accounting was sought for each MED indicated on the list. |

**RESPONSE**

The Company sought deferral accounting for each MED experienced during the time period 2021 through 2023. Please see the following table for the requested information, which includes all Major Event Days experienced by the Company from 2021 through 2023 and the corresponding case number in which the Commission approved deferral of the applicable major storm expense. This information corresponds to information included as part of Figure SDB-6 in Company Witness Blankenship's Direct Testimony in this proceeding.

| Deferral Approved in Case No. | Storm Dates |
|---|---|
| 2020-00368 | January 11, 2020 |
| | April 8-9, 2020 |
| | April 12, 2020 |
| 2021-00135 | December 24-25, 2020 |
| 2021-00129 | February 10-11, 2021 |
| | February 15-16, 2021 |
| | February 17, 2021 |
| 2021-00402 | February 28, 2021 |
| 2022-00293 | June 17, 2022 |
| | July 26, 2022 |
| 2023-00137 | March 3, 2023 |
| | March 25, 2023 |
| | April 1, 2023 |

Witness: Everett G. Phillips

Witness: Stephen D. Blankenship

Witness: Heather M. Whitney

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

## DATA REQUEST

**KPSC PHDR_19** Provide the "After Action Report" for each the eleven major storm events for which Kentucky Power has requested and received deferral accounting.

## RESPONSE

Please see the following table and corresponding attachments for the requested information. After Action Reports (AAR) are completed on a case-by-case basis.

<table>
<tr><th>Storm Dates</th><th>After Action Report (AAR) Information</th></tr>
<tr><td>January 11, 2020</td><td>No AAR was conducted, as no Mutual Assistance was needed for the storm.</td></tr>
<tr><td>April 8-9, 2020</td><td rowspan="2">See KPCO_R_PHDR_19_Attachment1 for the AAR for the April 8-9, 2020 and April 12, 2020 storms.</td></tr>
<tr><td>April 12, 2020</td></tr>
<tr><td>December 24-25, 2020</td><td>No AAR was conducted, as ICS was not activated and no Mutual Assistance was needed for the storm.</td></tr>
<tr><td>February 10-11, 2021</td><td rowspan="4">See KPCO_R_PHDR_19_Attachment2 for the AAR for the February 10-11, 2021, February 15-16, 2021, February 17, 2021, and February 28, 2021 storms.</td></tr>
<tr><td>February 15-16, 2021</td></tr>
<tr><td>February 17, 2021</td></tr>
<tr><td>February 28, 2021</td></tr>
<tr><td>June 17, 2022</td><td>No AAR was conducted for this storm, as the amount of weather-related events (2 major, 4 minor) from June through early August precluded completing an AAR. Included in this timeframe was the flood event.</td></tr>
<tr><td>July 26, 2022</td><td>See KPCO_R_PHDR_19_Attachment3 for the AAR for the July 26, 2022 storm.</td></tr>
<tr><td>March 3, 2023</td><td rowspan="3">See KPCO_R_PHDR_19_Attachment4 for the AAR for the March 3, 2023, March 25, 2023, and April 1, 2023 storms.</td></tr>
<tr><td>March 25, 2023</td></tr>
<tr><td>April 1, 2023</td></tr>
</table>

Witness: Stephen D. Blankenship

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_20** | Refer to the Hearing Testimony of Scott Bishop. Provide the referenced market potential study. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_20_Attachment1.

Witness: Scott E. Bishop

GDS Associates, Inc.
ENGINEERS & CONSULTANTS
gdsassociates.com

*prepared for*

Kentucky Power Company

KENTUCKY POWER
An AEP Company

# 2023 POTENTIAL STUDY

## FINAL REPORT

June 2023

*prepared by*

GDS ASSOCIATES INC
BRIGHTLINE GROUP

# 1 EXECUTIVE SUMMARY

## 1.1 BACKGROUND & STUDY SCOPE

Kentucky Power Company ("Kentucky Power") commissioned GDS Associates ("GDS") and Brightline Group, collectively "the GDS Team", to assess energy savings potential in the Kentucky Power service area to help inform future planning efforts. Separate estimates of electric energy efficiency and distributed energy resource ("DER") potential were developed.

In addition, Kentucky Power also requested that GDS conduct limited primary market research to help inform key inputs in the market potential analysis. The desired final research focused on 1) collecting updated equipment penetration, saturation, and efficiency characteristics, 2) site conditions related to distributed energy resources, and 3) customer willingness to participate ("WTP")[1] in program offerings across select end-uses/measures.

## 1.2 TYPES OF POTENTIAL ANALYZED

This potential study provides a roadmap for both policy makers and Kentucky Power as they develop strategies and programs for energy efficiency ("EE") and distributed energy resources in the Kentucky Power service area. In addition to technical and economic potential estimates, the development of achievable and program potential estimates for a range of feasible measures is useful for program planning and modification purposes. Unlike achievable and program potential estimates, technical and economic potential estimates do not include customer acceptance considerations for measures, which are often among the most important factors when estimating the likely customer response to new programs. For this study, the GDS Team produced the following estimates of demand side management potential:

- Technical potential
- Economic potential
- Achievable potential
    - Maximum achievable potential ("MAP")
    - Realistically achievable potential ('RAP")
- Program potential
    - Based off of RAP

## 1.3 APPROACH SUMMARY

The purpose of this market potential study is to provide a foundation for the continuation of utility-administered energy efficiency, and determine the remaining opportunities for cost-effective energy savings, demand savings, and distributed energy resources for the Kentucky Power service area. This study has examined a full array of technologies, programs, and energy efficient building practices that are technically achievable.

The GDS Team used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial sector, the GDS Team utilized a top-down modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load. A top-down approach is preferred for the commercial sector because of the heterogeneous make-up of the sales forecast (wide variety of end-uses and business types). Bottom-up approaches were also used in the DER analyses for all sectors.

[1] See Appendix A for a Glossary of terms and acronyms.

## 1.4 STUDY LIMITATIONS AND CAVEATS

As with any assessment of potential, this study necessarily builds on various assumptions and data sources, including the following:

- Energy efficiency measure lives, savings, and costs (total measure costs, incremental costs, and incentive costs)
- Projected penetration rates for energy efficiency measures
- Projections of energy avoided costs
- Future known changes to codes and standards
- End-use saturations and fuel shares

While the GDS Team has sought to use the best and most current data available (including the use of new primary market research in key market subsegments of interest based on stakeholder feedback) there are often reasonable alternative assumptions which would yield slightly different results. For instance, the analysis assumes that many existing measures, regardless of their current efficiency levels, can be eligible for future installation and savings opportunities. Other studies may select a narrower viewpoint, limiting the amount of potential from equipment that is already considered to be energy efficient. Additionally, the models used in this analysis must make several assumptions regarding program delivery and the timing of equipment replacement that may ultimately occur more rapidly (or more slowly) than currently forecasted.

Furthermore, while the lists of energy efficiency measures examined in this study analysis represent technologies available in the market today as well as a limited number of emerging technologies not currently offered in Kentucky Power's service territory, these measure lists may not be exhaustive. The GDS Team acknowledges that new efficient technologies may become available over the course of the 20-year study timeframe that could produce efficiency gains and costs at different levels than those currently assumed.

Last, where possible, the GDS Team and Kentucky Power collaborated to ensure consistency with assumptions and methodological considerations that are expected to be employed during the program planning process. However, final program designs and implementation strategies may need additional flexibility to target specific or underserved markets, address equity concerns, or react to changing customer preferences.

## 1.5 POTENTIAL SAVINGS OVERVIEW

The following several sub-sections provide an overview of the energy efficiency potential as well as a summary of distributed energy resource potential. Chapters 4 through 6 of this report provide additional summary data and methodological considerations and descriptions.

### *1.5.1 Market Research Summary*

Primary market research activities were focused on collecting updated equipment penetration, saturation, and efficiency characteristics; and customer willingness to participate in program offerings across select end-uses/measures. The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and develop expected long-term adoption rates for energy efficiency, demand response, and distributed energy resources over the study horizon. This data flowed through technical, economic and achievable potential analyses, as well as the program design analysis.

### *1.5.2 Energy Efficiency Potential for Residential Customers*

Figure 1-1 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The cumulative annual 3-year technical potential is 11% of forecasted sales, and the economic potential is 9% of forecasted sales. The cumulative annual 3-year MAP is 1.8% and the RAP is 1.1%, as a percentage of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 39% and 32% of forecasted sales, respectively. This indicates that a large portion of the technical potential is cost-effective. The MAP and RAP rise respectively to 17% and 11% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 1-1: OVERVIEW OF RESIDENTIAL POTENTIAL

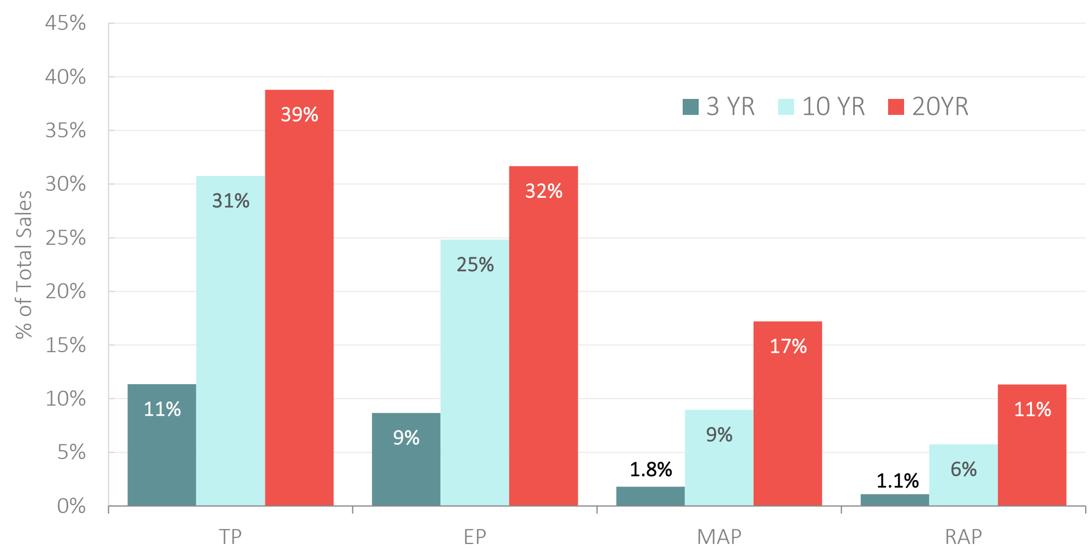



Table 1-1 provides cumulative annual technical and economic potential results across the 2024-2028 (Years 1-5) timeframe, as well as for 2033 (10th-year) and 2043 (20th-year). The technical potential is more than 331,000 MWh by 2028 and rises to more than 666,000 MWh by 2043. Economic potential rises to more than 257,000 MWh by 2028. Technical potential summer peak demand savings reaches 244 MW by 2043 and winter peak demand savings reaches approximately 92 MW by 2043.

TABLE 1-1 TECHNICAL & ECONOMIC RESIDENTIAL POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | | |
| **Technical** | 80,471 | 149,002 | 214,554 | 273,966 | 331,832 | 553,739 | 666,952 |
| **Economic** | 62,376 | 113,778 | 164,098 | 211,339 | 257,585 | 446,652 | 544,564 |
| **Summer Demand (MW)** | | | | | | | |
| **Technical** | 29.6 | 57.2 | 84.1 | 105.9 | 127.3 | 213.3 | 243.9 |
| **Economic** | 20.9 | 40.0 | 58.9 | 75.4 | 91.6 | 159.9 | 185.2 |
| **Winter Demand (MW)** | | | | | | | |
| **Technical** | 10.8 | 20.0 | 28.8 | 36.8 | 44.5 | 73.6 | 91.6 |
| **Economic** | 8.4 | 15.2 | 21.8 | 27.9 | 33.8 | 57.6 | 72.2 |

### *1.5.3 Energy Efficiency Potential for Commercial Customers*

Figure 1-2 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The cumulative annual 3-year technical potential is 8% of forecasted commercial sales, and the economic potential is 6% of forecasted commercial sales. The cumulative annual 3-year MAP is 3.0% and the RAP is 2.3%, as a percentage of forecasted commercial sales. Over the duration of the study timeframe the technical rises to 28% and economic potential rises to 20% of forecasted commercial sales.[2] The MAP and RAP rise respectively to 15% and 12% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 1-2: OVERVIEW OF COMMERCIAL POTENTIAL

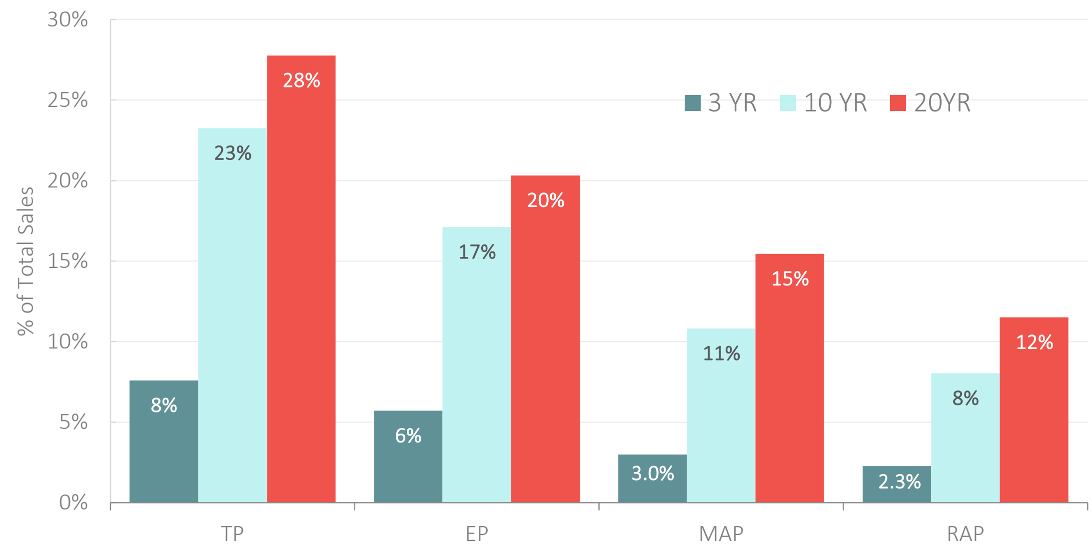



Table 1-2 provides cumulative annual technical and economic potential results across the 2024-2028 (Years 1-5) timeframe, as well as for 2033 (10th-year) and 2043 (20th-year). The technical potential is just above 232,000 MWh by 2028 and rises to more than 490,000 MWh by 2043. Economic potential rises to more than 358,000 MWh by 2043. Technical potential summer peak demand savings reaches 101 MW by 2043 and winter peak demand savings reaches approximately 48 MW by 2043.

TABLE 1-2 TECHNICAL & ECONOMIC COMMERCIAL POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | | |
| **Technical** | 43,541 | 90,256 | 138,295 | 186,119 | 232,533 | 416,505 | 490,105 |
| **Economic** | 32,833 | 67,950 | 103,914 | 139,507 | 173,783 | 306,552 | 358,764 |
| **Summer Demand (MW)** | | | | | | | |
| **Technical** | 7.7 | 16.3 | 25.3 | 34.6 | 43.7 | 83.1 | 101.4 |
| **Economic** | 4.8 | 9.9 | 15.3 | 20.8 | 26.1 | 47.2 | 55.8 |
| **Winter Demand (MW)** | | | | | | | |
| **Technical** | 4.5 | 9.3 | 14.2 | 19.0 | 23.6 | 41.4 | 47.9 |
| **Economic** | 3.7 | 7.7 | 11.7 | 15.7 | 19.6 | 34.5 | 40.6 |

[2] The savings as a percentage of sales noted for the commercial sector here and throughout the report are indicative of the MWh savings as a percentage of the eligible sales forecast (i.e. ineligible sales associated with customers forecasted to opt-out of energy efficiency programs are not included in the denominator). The 20-yr RAP of 12% of commercial sales drops to 5.8% as a percentage of all commercial and industrial sales.

### 1.5.4 Distributed Energy Resource Potential for All Customers

Table 1-3 and Table 1-4 summarize the solar photovoltaic ("PV") potential for the residential and non-residential sectors, respectively. It is notable that the non-residential sector potential sector is significantly less than residential potential. This difference is largely due to National Renewable Energy Laboratory ("NREL") coefficients.

**TABLE 1-3 SUMMARY OF SOLAR PV DC CAPACITY MARKET POTENTIAL (RESIDENTIAL)**

| Year | Scenario | Single-Family (MW) | Mobile Home (MW) | Multifamily (MW) |
|---|---|---|---|---|
| **2027** | Technical | 3.0 | 0.1 | 0.0 |
| **2033** | Technical | 27.3 | 0.7 | 0.4 |
| **2043** | Technical | 447.0 | 10.8 | 2.5 |
| **2027** | BAU[3] | 1.6 | 0.0 | 0.0 |
| **2033** | BAU | 5.9 | 0.1 | 0.0 |
| **2043** | BAU | 34.6 | 0.8 | 0.2 |

**TABLE 1-4 SUMMARY OF SOLAR PV DC CAPACITY MARKET POTENTIAL (NON-RESIDENTIAL)**

| Year | Scenario | Non-Residential (MW) |
|---|---|---|
| **2027** | Technical | 0.1 |
| **2033** | Technical | 0.4 |
| **2043** | Technical | 5.9 |
| **2027** | BAU | 0.0 |
| **2033** | BAU | 0.0 |
| **2043** | BAU | 0.1 |

Table 1-5 and Table 1-6 summarize the solar PV potential above in energy metrics. The 2043 technical market potential for solar PV represents 9.0% of the 2043 energy sales forecast for all sectors. 2043 technical market potential for solar PV in the residential sector represents 27.0% of the 2043 energy sales forecast for the residential sector.

**TABLE 1-5 SUMMARY OF SOLAR PV ENERGY MARKET POTENTIAL (RESIDENTIAL)**

| Year | Scenario | Single-Family (MWh) | Mobile Home (MWh) | Multifamily (MWh) |
|---|---|---|---|---|
| **2027** | Technical | 2,982 | 130 | 44 |
| **2033** | Technical | 27,000 | 1,175 | 386 |
| **2043** | Technical | 441,655 | 19,227 | 2,757 |
| **2027** | BAU | 1,617 | 70 | 15 |
| **2033** | BAU | 5,865 | 255 | 53 |
| **2043** | BAU | 34,235 | 1,490 | 227 |

[3] Business-as-Usual. See Section 6.1.3 for more details.

TABLE 1-6 SUMMARY OF SOLAR PV ENERGY MARKET POTENTIAL (NON-RESIDENTIAL)

| Year | Scenario | Non-Residential (MWh) |
|---|---|---|
| **2027** | Technical | 17,526 |
| **2033** | Technical | 162,771 |
| **2043** | Technical | 6,464,382 |
| **2027** | BAU | 1,235 |
| **2033** | BAU | 4,710 |
| **2043** | BAU | 43,715 |

### *1.5.5 Program Design Recommendations Summary*

The GDS Team conducted research and analysis to provide a recommendation for Kentucky Power to consider as potential improvements to their electric energy efficiency program portfolio. The primary objective is to expand energy efficiency for all customers with specific emphasis on low and moderate level income residential customers. The GDS Team combined market research of regional peer electric energy efficiency programs with the realistic potential outcomes from the marker potential assessment, in addition to current industry trends and best practices.

Figure 1-3 and Figure 1-4 summarize the proposed program potential budgets and expected energy savings.

FIGURE 1-3: FIVE-YEAR ENERGY EFFICIENCY PORTFOLIO BUDGET EXPENDITURE FORECAST

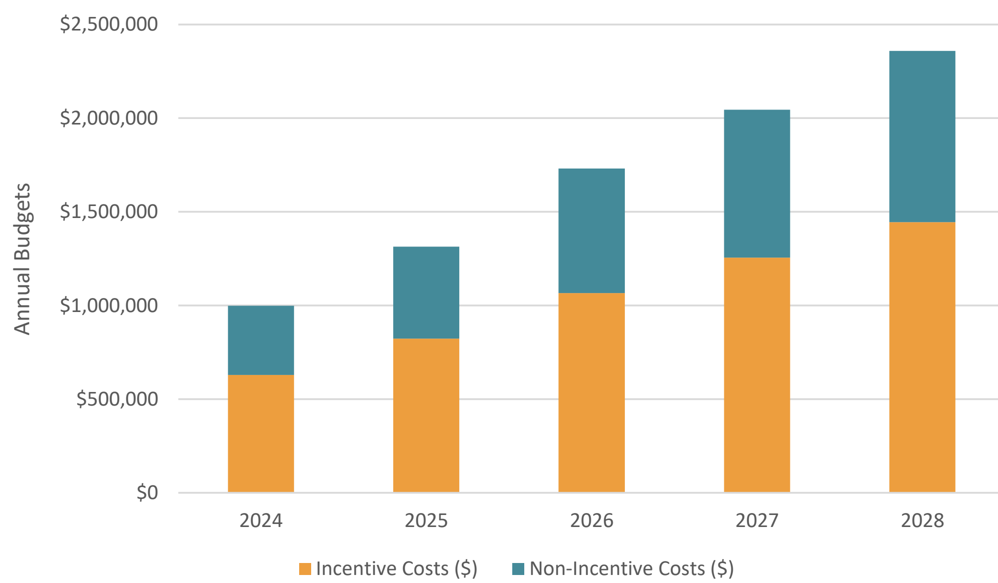


FIGURE 1-4: FIVE-YEAR ENERGY EFFICIENCY PORTFOLIO ENERGY SAVINGS (NET) FORECAST

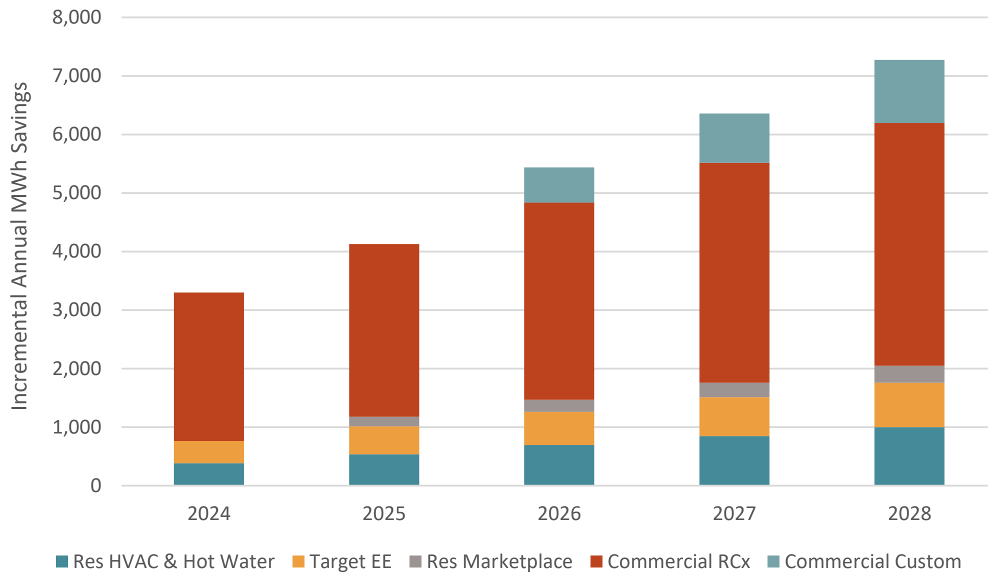



Table 1-7 below provides a comparison of the incremental annual savings and budgets in the MAP, RAP, and program potential scenarios. The Program Potential savings are on average about 29% of the RAP savings, and the Program Potential budgets are on average about 17% of the RAP budgets.

TABLE 1-7 SAVINGS AND BUDGETS COMPARISON – ACHIEVABLE AND PROGRAM POTENTIAL SCENARIOS

| | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | |
| **MAP** | 25,329 | 28,959 | 31,136 | 33,529 | 35,618 |
| **RAP** | 17,771 | 20,221 | 21,662 | 23,089 | 24,528 |
| **Program** | 3,297 | 4,121 | 5,431 | 6,349 | 7,267 |
| **Summer Demand (MW)** | | | | | |
| **MAP** | 5.0 | 5.8 | 6.2 | 7.2 | 7.6 |
| **RAP** | 3.0 | 3.5 | 3.8 | 4.3 | 4.6 |
| **Program** | 0.4 | 0.6 | 1.0 | 1.3 | 1.6 |
| **Budgets** | | | | | |
| **MAP** | $14,743,927 | $17,356,129 | $19,032,236 | $21,452,626 | $23,375,497 |
| **RAP** | $7,443,314 | $8,926,621 | $9,886,231 | $11,093,144 | $12,225,682 |
| **Program** | $1,025,012 | $1,330,769 | $1,749,654 | $2,067,654 | $2,386,309 |

The program design recommendations include the following four programs:

- **<u>Targeted Energy Efficiency Program</u>** – This is a program dedicated to low-income Kentucky Power customers which are eligible for Weatherization Assistance Program. Measures include air source heat pumps, efficient water heaters and other building shell and water heating retrofit measures. The Targeted Energy Efficiency program should increase spending in the next few years, seeking to double funding by program year three through the following actions: increase payment amounts for completed energy audits with the intention to increase the number of completed audits and increase the comprehensiveness of energy audits; increase incentives for replaced and upgraded HVAC equipment. It is understood that the Targeted Energy Efficiency program has operated for several years with consistent funding. There should be modest expectation on program growth with additional funds as program operations are not directly within Kentucky Power's influence.

- **Home Energy Improvement Program** – This program will promote energy efficiency improvements in existing homes and provide financial incentives and assessments for implementing eligible energy efficiency measures. The program provides customers, remodelers, and property owners with individual improvement options for HVAC and weatherization technologies.

- **Marketplace Program** – This is an on-line and easy-to-reach shopping platform for energy efficiency technologies found in customer homes and small businesses, such as thermostats, smart plug strips, and potentially small appliances. The Marketplace program is slated to begin in 2025.

- **Commercial Prescriptive Program** – This program provides incentives to reduce the incremental cost to upgrade to high-efficiency lighting equipment and controls over standard efficiency options for new and existing commercial customers. The program includes equipment with easily calculated savings and provides straightforward and easy participation for customers. A variety of measures are eligible for an incentive, including LEDs, lighting controls, smart thermostats, and air source heat pumps.

- **Commercial Custom Program** - This program provides a platform for comprehensive energy efficiency projects in existing and new facilities that go beyond discrete measures and common, measure-level efficiency practices. The Commercial Custom Program provides incentives for efficiency improvements not included in the Commercial Prescriptive Program. It is anticipated that this program will be introduced in the third year of the portfolio (2026) due to additional complexity.

# 2 MARKET RESEARCH

The initial step in the assessment of future potential is to develop a clear understanding of the current market segments, as well as a clear understanding of the market research data available in the Kentucky Power service area. In 2022 Kentucky Power requested the GDS Team to conduct market research that would inform critical elements of the market potential study. The research objectives were developed in coordination with Kentucky Power and the potential study team. Primary market research activities were focused on collecting updated equipment penetration, saturation, and efficiency characteristics; and customer willingness to participate in program offerings across select end-uses/measures.

The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and develop expected long-term adoption rates for energy efficiency, demand response, and DERs over the study horizon. The GDS Team conducted surveys of business and residential customers during December of 2022 and January of 2023 with the objectives of gathering primary data on the following topics:

- Willingness to participate in a variety of energy efficiency, demand response and distributed energy resource program scenarios.
- Baseline / Saturation of energy-using equipment
- Barriers

Survey results served as inputs for the market potential model, enabling the market potential analysis to take into consideration the specific market conditions that exist in Kentucky Power's service territory. Data collection results specific to the Kentucky Power service area are provided below.

## 2.1 PRIMARY DATA COLLECTION

The following subsections provide an overview of the primary data collection activities conducted by the GDS Team to support the market potential analysis of energy efficiency, demand response, and DER potential. The GDS Team conducted survey research in the residential and non-residential sectors.

### *2.1.1 Survey Administration*

Surveys were administered in an online format through SurveyMonkey, with email recruitment followed by one reminder email. Due to a lower than ideal response rate on the residential surveys, a second sample group was emailed for both residential surveys.

Respondents who completed the survey were entered into a drawing to win an electronic gift card. $100 gift cards were awarded to twenty randomly selected residential survey respondents (10 for the baseline survey and 10 for the WTP survey) and $200 gift cards were awarded to ten randomly selected business survey respondents. Winners were given the choice of an electronic or physically mailed gift card.

### *2.1.2 Sampling Approach*

The team developed a sampling approach with an objective of achieving industry-standard statistical significance (90% confidence, 10% relative precision, or 90/10) at the strata level for all questions. Overall, the response outcomes were positive, and the survey effort produced a robust set of primary data. The team set aggressive sampling targets, with a goal of having high levels of statistical significance for detailed sub-groups within the population. Table 2-1 sampling targets and response outcomes.

The business survey was split into two different groups, with one group seeing the baseline questions first and the other group seeing the WTP questions first, to ensure that incomplete surveys did not affect one group of questions more than another.

**TABLE 2-1 SURVEY SAMPLING TARGETS AND RESPONSE SUMMARY[4]**

| State | Target Completes | Completes (Entire Survey) | Completes (Baseline Questions) | Completes (WTP Questions) |
|---|---|---|---|---|
| **Nonresidential Customer Survey** *Stratification: Tariff Group* | | | | |
| **Commercial** | **70** | **102** | 110 | 119 |
| **Residential Customer Survey** *Stratification: single family / multifamily / mobile home, and income-qualified / market rate* | | | | |
| Single Family | **70** | 213 | 112 | 101 |
| Multi-Family | 36 | 68 | 44 | 24 |
| Mobile Home | 70 | 186 | 95 | 91 |
| Total | 210 | 467 | 251 | 216 |

### *2.1.3 Residential Online Survey*

The residential customer research targeted homeowners and tenants in the following key segments: income-eligible and market-rate customers, and customers occupying single family, multifamily, and mobile homes. Income-eligible was defined by household size as 200% of the federal poverty threshold.

A residential online customer survey collected home characteristics, equipment penetration for key end-uses/building characteristics, including heating, cooling, water heating, insulation, smart appliances, thermostats, major appliances, and electric vehicles – and information on barriers and willingness to adopt a range of energy efficient measures at varying incentive levels. Table 2-2 provides the targeted and completed residential online surveys.

**TABLE 2-2 TARGETED AND COMPLETED RESIDENTIAL SECTOR ONLINE SURVEYS**

| Strata | Target Sample Size | Total Completed |
|---|---|---|
| Single Family – Market Rate | 35 | 156 |
| Multifamily – Market Rate | 18 | 52 |
| Mobile Home – Market Rate | 35 | 117 |
| Single Family – IQ | 35 | 57 |
| Multifamily – IQ | 18 | 16 |
| Mobile Home - IQ | 35 | 69 |

### *2.1.4 Business Sector Online Survey*

Primary data collection was also conducted in the nonresidential sector via an online survey with business customers. The survey collected business and facility characteristics, as well as equipment penetrations for key end-uses, such as lighting, heating, cooling, water heating, refrigeration, thermostats, ventilation, data centers, smart strips, EMS, and on-site generation (including solar PV systems). The nonresidential online survey also collected information on barriers to energy efficiency and willingness-to-adopt energy efficient measures

[4] The survey was split into two groups, one which saw the baseline questions first, and one that saw the WTP questions first. Within each group, some respondents completed just the baseline questions, some completed just the WTP questions, and some completed both. This explains why the number of completes for baseline and WTP are each individually higher than the number of completes for the entire survey.

under various incentive offerings. In total, GDS collected survey data from 238 commercial customers, with 102 fully completing the survey. GDS examined the annual energy consumption data from the survey participants and developed a weighting adjustment based on the sample's customer type relative to the Kentucky Power population.

## 2.2 RESIDENTIAL MARKET DATA

The tables below provide some key home and equipment characteristics by market segment. The results have been weighted to align the sample distribution with that of the overall residential population home types for Kentucky Power.

Table 2-3 presents some key household and equipment characteristics for the residential sector by Kentucky Power housing type and income type. The data presented below includes the average number of units per household for occupants, water devices, plug load controls, and key appliances.

**TABLE 2-3: KEY HOUSEHOLD AND EQUIPMENT CHARACTERISTICS (AVG # PER HOUSEHOLD)**

| | Total | Single Family | Multi-Family | Mobile Home | Market Rate | Income Qualified |
|---|---|---|---|---|---|---|
| **Household Characteristics** | | | | | | |
| Avg. # of Occupants | 2.3 | 2.3 | 1.8 | 2.4 | 2.4 | 2.2 |
| Avg # of Dishwashers | 0.5 | 0.6 | 0.3 | 0.4 | 0.3 | 0.6 |
| Avg # of EnergyStar Dishwashers | 0.4 | 0.5 | 0.2 | 0.2 | 0.2 | 0.4 |
| Avg # of Smart Plugs/Outlets | 0.3 | 0.3 | 0.3 | 0.2 | 0.2 | 0.3 |
| Avg # of Refrigerators | 1.2 | 1.3 | 1.0 | 1.1 | 1.2 | 1.2 |
| Avg # of EnergyStar Refrigerators | 0.8 | 0.9 | 0.6 | 0.7 | 0.7 | 0.8 |
| Avg # of Stand-Alone Freezers | 0.6 | 0.7 | 0.3 | 0.5 | 0.5 | 0.6 |
| Avg # of EnergyStar Stand-Alone Freezers | 0.3 | 0.4 | 0.2 | 0.3 | 0.3 | 0.3 |
| Avg # of Thermostats | 0.9 | 1.0 | 0.8 | 0.8 | 0.8 | 0.9 |

Table 2-4 provides example summary data by market segment for major residential end-uses. These data points of electric heating, water heating, and central air conditioning equipment penetrations help quantify the proportion of the population with electricity consuming major equipment types by market segment. In addition, the research also provided recent market conditions for remaining efficiency opportunities, such as the penetration of smart thermostats, which does not exceed 14% for any market segment.

**TABLE 2-4: SELECT RESIDENTIAL MARKET RESEARCH RESULTS FOR KEY END-USES**

| End-Use | Equipment | Total | Single Family | Multi-Family | Mobile Home | Market Rate | Income Qualified |
|---|---|---|---|---|---|---|---|
| Water Heating | Electric Water Heating | 81% | 77% | 73% | 89% | 83% | 80% |
| | Heat Pump Water Heater *(as a % of electric Water Heating)* | 18% | 17% | 33% | 16% | 30% | 15% |

| End-Use | Equipment | Total | Single Family | Multi-Family | Mobile Home | Market Rate | Income Qualified |
|---|---|---|---|---|---|---|---|
| Heating | Fuel - Electricity | 70% | 66% | 80% | 75% | 75% | 70% |
| | Fuel - Natural Gas | 20% | 28% | 17% | 8% | 9% | 22% |
| | Fuel - Other | 10% | 7% | 2% | 17% | 16% | 8% |
| | Type - Non-Electric Furnace | 7% | 10% | 2% | 3% | 3% | 7% |
| | Type - Heat Pump | 48% | 53% | 35% | 45% | 44% | 48% |
| | Type - Electric Furnace | 18% | 13% | 24% | 26% | 24% | 18% |
| | Type - Other | 26% | 24% | 39% | 26% | 29% | 27% |
| Cooling | Have Central AC | 74% | 80% | 87% | 63% | 60% | 80% |
| Thermostats | Have Smart/Wi-Fi Thermostat | 10% | 14% | 2% | 5% | 4% | 10% |
| DER | Electric Vehicle | 1% | 0% | 2% | 1% | 0% | 1% |

## 2.3 BUSINESS MARKET DATA

Table 2-5 provides select demographic information in the business sector.

TABLE 2-5 COMMERCIAL BUILDING CHARACTERISTICS

| | Total |
|---|---|
| **Own** | 80% |
| **Lease** | 17% |
| | |
| **Manage Building (Lease Only)** | 51% |
| **Do Not Manage Building (Lease Only)** | 44% |
| | |
| **% of Facilities Built Before 2001** | 49% |
| **Average Size of Facility (Sq. Ft)** | 3,145 |
| **Occupy Building Year-Round** | 81% |

The penetration of different lighting fixtures in Kentucky Power businesses is shown in Table 2-6. The table also includes the % of facilities with different lighting control types as well as % of lighting that is controlled. Table 2-7 provides example summary data for major end-uses.

TABLE 2-6: COMMERCIAL SECTOR LIGHTING END-USE CHARACTERISTICS

| End Use | Equipment | Total |
|---|---|---|
| Lighting *(% of all Lighting)* | **Linear Fluorescent** | 39% |
| | **Linear LED** | 33% |
| | **Nonlinear LED** | 11% |
| | **CFL** | 4% |
| | **HID** | 2% |
| | **Incandescent or Halogen** | 11% |
| Lighting Controls | **Occupancy Sensors** | 10% |
| | *% of Lighting Controlled* | 5% |
| | **Daylight Dimming** | 4% |

| End Use | Equipment | Total |
|---|---|---|
| | *% of Lighting Controlled* | 1% |
| | **Time Controls** | 7% |
| | *% of Lighting Controlled* | 3% |
| | **Advanced Lighting Controls** | 7% |
| | *% of Lighting Controlled* | 5% |

TABLE 2-7 COMMERCIAL SECTOR EQUIPMENT PENETRATION ACROSS KEY END-USES

| End Use | Equipment | Penetration |
|---|---|---|
| | | Total |
| Heating | Boiler | 1% |
| | Furnace | 15% |
| | Heat Pump | 33% |
| | Electric Resistance | 5% |
| | Unit Heater | 11% |
| | Infrared | 5% |
| Cooling | Packaged System AC | 32% |
| | Split System AC | 18% |
| | Heat Pump (Ducted) | 28% |
| | Heat Pump (Ductless) | 6% |
| | Window or Wall AC | 11% |
| Thermostats | Smart Thermostats | 9% |
| | % of Space Controlled by Smart Thermostat | 58% |
| Ventilation | Demand Controlled Ventilation | 26% |
| | Vent Hoods | 20% |
| | Vent Hoods with Demand Controlled Vent. | 44% |
| Smart Strips | Smart Strips (% of All Strips) | 45% |
| Water Heating | Electric WH | 75% |
| On-Site Generation | Renewable Energy Generation | 0% |
| | Emergency/Backup Generation | 100% |

## 2.4 ADOPTION CURVE MARKET DATA

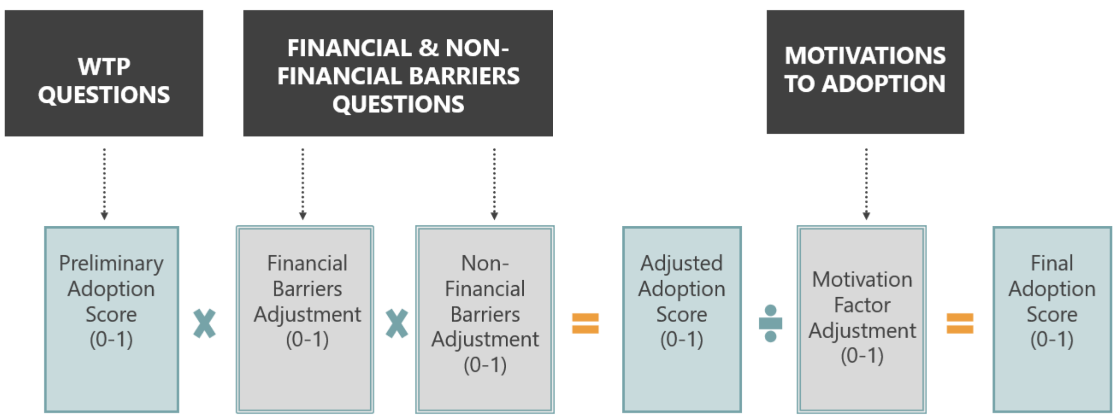
In addition to new primary research on building and energy-consuming equipment characteristics in the Kentucky Power service area, one of the major objectives of the primary research was to develop survey research that could be utilized to develop measure/program adoption curves for estimates of achievable potential. Table 2-8 describes the end-uses or categories in which adoption rate estimates were developed for energy efficiency, demand response programs, or distributed energy resources by the GDS Team.

**TABLE 2-8 ADOPTION RATE CATEGORIES ANALYZED**

| Willingness to Participate | EE End Uses | DR Programs | DER |
|---|---|---|---|
| **Residential Customers** | Heating/CAC<br>Water Heating<br>Major Appliances<br>Insulation/Air Sealing | Thermostat DR[5] | Solar PV (Purchase)<br>Electric Vehicles (EVs) |
| **Business Customers** | HVAC Equipment<br>Water Heating Equip.<br>Refrigeration<br>Lighting Equipment | N/A | Solar PV (Purchase and Lease) |

Adoption rate calculations were based on questions which assessed (1) the respondent's willingness to adopt energy efficiency technologies or participate in demand response programs in scenarios with varying levels of program support, (2) the magnitude of the respondent's financial and non-financial barriers to adoption/participation. Adoption rates were calculated based on the equation shown below.

**EQUATION 2-1 ADOPTION RATE FORMULA FOR FINAL ADOPTION SCORE**




Direct willingness-to-participate questions are the starting point of measure/program-specific adoption curve calculations. For each item, respondents were asked to rate the likelihood that they would purchase the energy efficient version of the equipment, or participate in the DR program, at various incentive levels, including no incentive and an incentive that covers the full incremental (or total) cost.

Responses to financial and non-financial barrier questions were then used to adjust the preliminary adoption score. If "cost" was a consideration to prevent customers from purchasing energy efficient equipment, GDS assumed a financial barrier adjustment. The 0% incentive level was reduced by 100%, the 25% incentive level was reduced by 80%, the 50% incentive level was reduced by 60%, the 75% incentive level was reduced by 40%, and the 100% incentive level was reduced by 20%.

If another reason (i.e., lack of knowledge, uncertainty about bill savings, etc.) was a consideration to prevent customers from purchasing energy efficient equipment, GDS assumed a non-financial barrier adjustment. The 0% incentive level was reduced by 50%, the 25% incentive level was reduced by 40%, the 50% incentive level

[5] Although the market research sought to understand customer attitudes and WTP in a thermostat DR program, subsequent estimates of potential focus on EE savings and do not include DR offerings.

was reduced by 30%, the 75% incentive level was reduced by 20%, and the 100% incentive level was reduced by 10%.

Last, if the respondent indicated a strong motivation for purchasing an efficient technology or participating in a demand response program (i.e. bill savings, progress towards sustainability goals, etc.) then the adjusted adoption score was increased. The 0% incentive was increased by 25%, the adjusted adoption rate at the 25% incentive level was increased by 66%, the 50% incentive level by 150%. Respondents who indicated a strong motivation factor were typically assigned a 100% adoption score at the 75% and 100% incentive levels.

### 2.4.1 Residential Sector Final Adoption Scores

Table 2-9 presents the adjusted adoption scores (after financial and non-financial adjustments) for residential customers. In general, residential customers indicated a willingness to participate close to 70% to 80% at 100% incentive levels, and even some modest level of willingness to participate with 0% incentives.

TABLE 2-9 RESIDENTIAL FINAL ADOPTION SCORES BY INCENTIVE LEVEL

| | Annual Incentive (% of incremental measure cost) | | | | |
|---|---|---|---|---|---|
| | 0% | 25% | 50% | 75% | 100% |
| HVAC | 18% | 36% | 52% | 66% | 80% |
| Water Heat | 15% | 26% | 39% | 54% | 76% |
| Insulation/Air Sealing | 14% | 23% | 36% | 50% | 74% |
| Appliances | 19% | 32% | 50% | 63% | 80% |
| Thermostat DR* | 21% | 33% | 47% | 58% | 64% |
| Solar Purchase | 6% | 14% | 29% | 50% | 75% |
| EVs | 4% | 8% | 22% | 35% | 52% |

**Thermostat DR has incentive levels of $10, $25, $50, $75 and $100/season.*

### 2.4.2 Business Sector Final Adoption Scores

Table 2-10 presents the adjusted adoption scores (after financial and non-financial adjustments) for Kentucky Power nonresidential customers across several end-uses.

In contrast to the residential sector energy efficiency WTP research, the nonresidential WTP survey questions incentives were described in the form of payback periods to better align with how purchasing decisions are likely to considered.

TABLE 2-10 NONRESIDENTIAL FINAL ADOPTION SCORES BY INCENTIVE LEVEL AND INVESTMENT TYPE

| | Payback Performance (after incentive) | | | | |
|---|---|---|---|---|---|
| | 10 Years | 5 Years | 3 Years | 1 Year | 0 Years |
| HVAC | 24% | 38% | 50% | 60% | 66% |
| Lighting | 27% | 43% | 52% | 64% | 73% |
| Refrigeration | 31% | 38% | 44% | 53% | 58% |
| Water Heat | 30% | 37% | 46% | 55% | 62% |
| Solar Purchase | 21% | 33% | 46% | 56% | 62% |
| Solar Lease* | 12% | 29% | 46% | 55% | 61% |

**Solar Lease did not use payback period. Instead, an estimation of the monthly lease cost was given based upon monthly average use ranges and related solar capacity sizes.*

Table 2-11 provides the final adoption scores for solar PV purchasing and/or leasing in the business sector.

**TABLE 2-11 NONRESIDENTIAL DER FINAL ADOPTION SCORES**

| Purchased Solar | Payback Years | | | | |
|---|---|---|---|---|---|
| | 10 YR | 5 YR | 3 YR | 1 YR | 0 YR |
| **Business** | 21% | 33% | 46% | 56% | 62% |
| **Solar Lease** | | | | | |
| | 0% | 25% | 50% | 75% | 100% |
| **Business** | 12% | 29% | 46% | 55% | 61% |

# 3 BASELINE FORECAST

The load forecast is a critical input into Kentucky Power's 2023 DSM Market Potential Study, having various uses in estimation of residential and business sector potential. Therefore, GDS reviewed Kentucky Power's most recently completed load forecast results and documentation to produce the various forecast components necessary as inputs into this analysis. This chapter describes the various ways in which the study uses the forecast and presents the baseline forecast and segmentation of the C&I classes and describes the methodology and data sources used by GDS for the purposes of generating the load forecasts that were used in the potential analysis.

## 3.1 ADJUSTMENTS TO THE KENTUCKY POWER LOAD FORECAST

Before assessing the future potential for energy efficiency, demand response, or distributed energy resources in the Kentucky Power service area, a few modifications to Kentucky Power's June 2022-vintage forecast were necessary to create an adjusted baseline forecast. These modifications are addressed in more detail below.

### *3.1.1 Reclassification of Load*

The 2022 Kentucky Power C&I sector customer database designates commercial and industrial rate code based on current tariff definition. Only using the account type/tariff definition to classify customers caused several manufacturing type premises to be classified as commercial (i.e. customers that are commercial rate codes but based on their description are manufacturing facilities), and several customers that GDS typically classifies as commercial to be classified as industrial, (i.e. a retail service building coded as an industrial account).

Additionally, the customer dataset identified each business by Standard Industry Code ("SIC"). The SIC was utilized to reclassify Kentucky Power C&I sector data. GDS mapped SIC's to a specified building type and then classified the building type as either commercial or industrial. Customers with a building type classified as "Industrial Manufacturing" were coded as Industrial customers. All other building types were coded as Commercial. While the goal for this analysis is to determine the actual amount of energy sales attributable to the commercial and industrial customer classes as a whole, it is only achievable by analyzing individual customer data. The result of this reclassification was a shift of approximately 4.5% of industrial sector sales, or 119,569 MWh, to the commercial sector. This 4.5% shift was then applied to the Kentucky Power base case forecasted sales for the commercial and industrial classes. It is important to have accurate energy sales by customer class so that specific DSM/EE programs have the correct amount of energy sales eligible for savings.

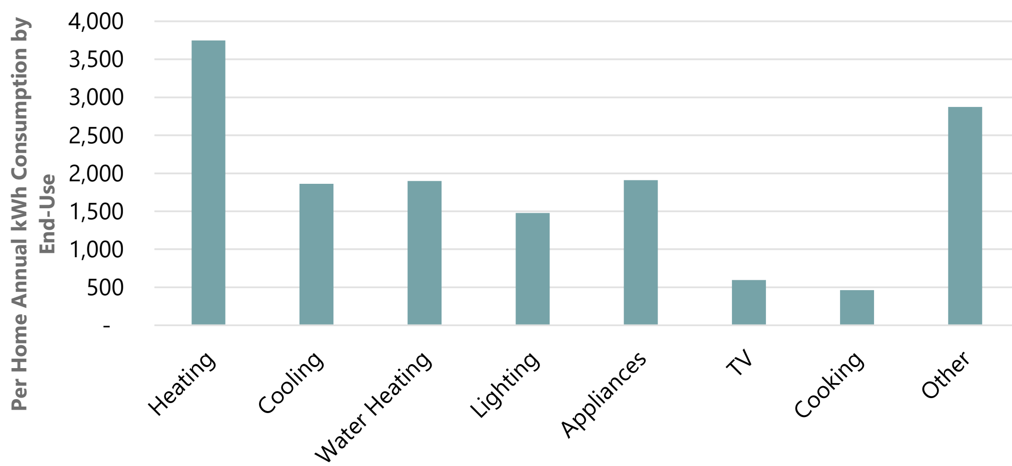
## 3.2 LOAD FORECAST DISAGGREGATION

The baseline forecasts represent projected total energy sales by class. For the potential studies, it is useful to have the class forecasts disaggregated in several different ways. This section presents the forecast disaggregation scenarios used by GDS to determine intensity by end-use.

### *3.2.1 Residential Sector*

The residential electric calibration effort led to an end-use intensity breakdown as shown below in Figure 3-1. Overall, the GDS Team estimated per home consumption to be 14,827 kWh per year. The "Heating" end use is the leading end-use, followed by the "Other" end use, which includes plug loads such as electronics and miscellaneous small appliances. The large share of the "Other" end use reflects the increasing prominence of electronics and other plug-in load devices within homes.

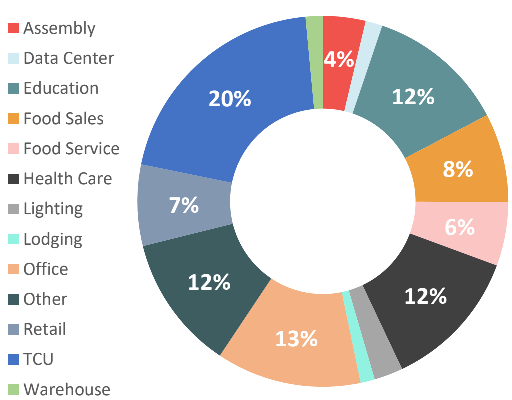
FIGURE 3-1 RESIDENTIAL ELECTRIC END-USE BREAKDOWN

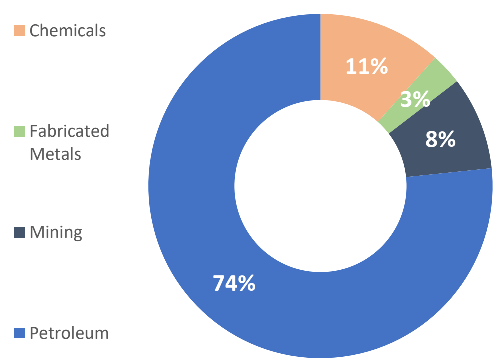



### *3.2.2 C&I Sector*

In the C&I sector, disaggregated forecast data provides the foundation for the development of energy efficiency potential estimates. GDS received a base case sales forecast from Kentucky Power for the residential, commercial and industrial sectors. As noted above, the C&I forecast was adjusted from the base case by using SIC information from Kentucky Power to reclassify usage as commercial or industrial. SIC information from Kentucky Power, along with Commercial Buildings Energy Consumption Survey ("CBECS") building type consumption tables, was then used to segment the forecast into building types. The forecast was further segmented into end-uses by building type using CBECS 2012 end-use survey data. Figure 3-2 provides a breakdown of commercial electric sales by building type and industrial sales by sector.[6] The industrial sector chart includes industry types with more than 1% of total electric sales, while the remaining 3% of sales not included in the chart are spread across a myriad of industries.

FIGURE 3-2: COMMERCIAL AND INDUSTRIAL ELECTRIC SALES BREAKDOWN BY BUILDING TYPE

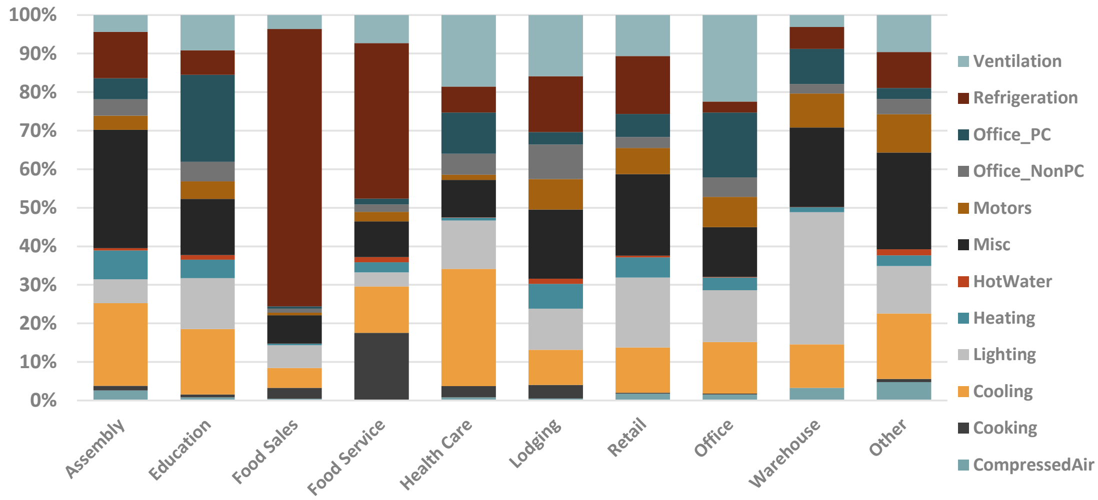



6 "Other" commercial building types include buildings that engage in several different activities, a majority of which are commercial (e.g. retail space), though the single largest activity may be industrial or agricultural; "other" also includes miscellaneous buildings that do not fit into any other category.

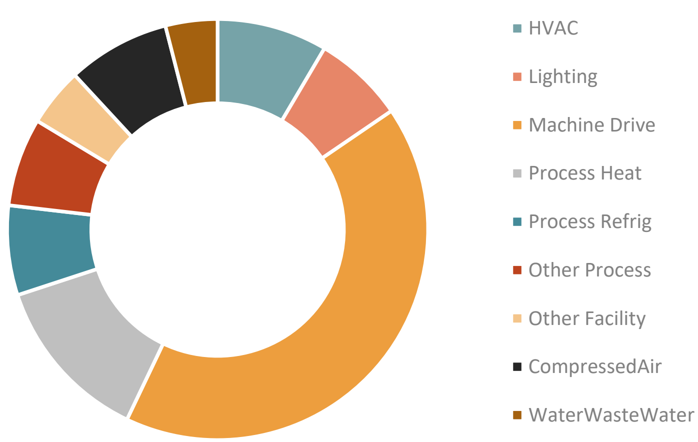
Figure 3-3 provides an illustration of the leading end-uses across all building types in the commercial sector. Lighting, space cooling, and ventilation are the primary end-uses with a significant share of load across most building types. Shares of refrigeration and office/computing are often dependent on the type of building, with refrigeration loads greatest in food sales and food service while office/computing loads are greatest in offices and education.

FIGURE 3-3: COMMERCIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE[7]




Industrial sales were also segmented by end-use based on the overall distribution of sales by industry type and EIA Manufacturing Energy Consumption Survey ("MECS") data on end-use consumption by industrial segment. Figure 3-4 provides a breakdown of the sales by end-use. Overall, the weighted average industrial sales by end-use in the Kentucky Power service area was roughly 42% Machine Drive, 13% Process Heat, 9% HVAC, 8% Compressed Air, 7% Lighting, and 7% Process Refrigeration. The remaining 15% was split between Other Process and Other Facility loads.

FIGURE 3-4: INDUSTRIAL ELECTRIC END-USE BREAKDOWN BY BUILDING TYPE




[7] Data labels for segments that contribute less than 5% of the total sector sales were removed to improve figure readability.

# 4 ENERGY EFFICIENCY POTENTIAL ANALYSIS

## 4.1 ANALYSIS APPROACH

This section describes the overall methodology utilized to assess the electric energy efficiency potential in the Kentucky Power service area. The main objectives of the energy efficiency potential analysis were to estimate the technical, economic, maximum, and realistic achievable potential savings from energy efficiency in the Kentucky Power service territory; and to quantify these estimates of potential in terms of MWh and MW savings, for each level of energy efficiency potential.

### *4.1.1 Overview of Approach*

For the residential sector, GDS utilized a bottom-up approach to the modeling of energy efficiency potential, whereby measure-level estimates of costs, savings, and useful lives were used as the basis for developing the technical, economic, and achievable potential estimates. The measure data was used to build-up the technical potential, by applying the data to each relevant market segment. The measure data allowed for benefit-cost screening to assess economic potential, which was in turn used as the basis for achievable potential, taking into consideration incentives and estimates of annual adoption rates. For the C&I sector, GDS employed a bottom-up/top-down approach. GDS first used a bottom-up approach to estimate measure-level savings, costs, and cost-effectiveness, and then converted to a top-down approach by applying measure savings (on a percent-basis) to all applicable shares of disaggregated energy load.

### *4.1.2 Market Characterization*

The initial step in the analysis was to gather a clear understanding of the current market segments in the Kentucky Power service area. The GDS Team coordinated with Kentucky Power to gather utility sales, customer data and existing market research to define appropriate market sectors, market segments, vintages, saturation data and end uses. This information served as the basis for completing a forecast disaggregation and market characterization of both the residential and nonresidential sectors.

#### *4.1.2.1 Forecast Disaggregation*

As noted in Chapter 3, through the development of the baseline forecasts, the GDS Team produced disaggregated forecasts by sector and end-use. The resulting aggregate baseline forecasts were disaggregated by sector and then further segmented as follows:

- ***Residential.*** The residential forecast was broken out by housing type between existing income qualified and market-rate customers as well as new construction.
- ***Commercial.*** Typically based on major EIA CBECS business types: retail, warehouse, food sales, office, lodging, health, food service, education, assembly, and miscellaneous.
- ***Industrial.*** As determined by actual load consumption shares and major industry types as defined by EIA's MECS data.

The segmentation analysis was performed by applying Kentucky Power-specific segment and end-use consumption shares, derived from Kentucky Power's customer database and industry code analysis (building segmentation), and by EIA Annual Energy Outlook (AEO) and MECS data (end-use segmentation) to forecast year sales. Within the residential, commercial, and industrial market segments, the sector level disaggregated forecasts were further segmented by the major end uses shown in Table 4-1.

TABLE 4-1: ELECTRIC END-USE LOADS

| | C&I | |
|---|---|---|
| **Residential** | **Commercial** | **Industrial** |
| Heating | Interior Lighting | Lighting |
| Cooling | Exterior Lighting | HVAC |
| Water Heating | Refrigeration | Machine Drive |
| Cooking | Space Cooling | Process Heat |
| Refrigerator | Space Heating | Process Cool / Refrigeration |
| Freezer | Ventilation | Other Process |
| Dishwasher | Water Heating | Process – Machine Drive |
| Clothes Washer | Plug Loads / Office Equipment | Other Facility |
| Dryer | Cooking | Compressed Air |
| TV | Other | Water / Wastewater |
| Light | Whole Building / Behavioral | Whole Building / Behavior |
| Miscellaneous | | |
| | | |
| | | |

#### *4.1.2.2 Eligible Opt-Out Customers*

In Kentucky Power's service territory, industrial customers are assumed to be eligible to opt-out of utility funded electric energy efficiency programs. As a result, GDS removed industrial sector customers and sales in the assessment of technical, economic, and achievable potential reflected in this report. As a sensitivity (included in the appendix), GDS examined the full potential in the C&I sector if these customers were no longer able to opt-out of utility-funded electric energy efficiency programs.

#### *4.1.2.3 Building Stock/Equipment Saturation*

To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary.

##### 4.1.2.3.1 Residential Sector

For the residential sector, GDS relied on the primary research efforts noted in Chapter 2 of this report. The GDS-led market research results allowed for the GDS Team to characterize the baseline and efficiency saturations of the residential sector using housing-type specific data. Other data sources included ENERGY STAR unit shipment data, and the EIA Residential Energy Consumption Survey data from 2020. The ENERGY STAR unit shipment data filled data gaps related to the increased saturation of energy efficient equipment across the U.S. in the last decade.

##### 4.1.2.3.2 Business Sector

For the commercial sector, building stock and equipment saturation data was informed from a combination of secondary data from available regional and/or national data, as well as limited primary market research (online surveys noted in Section 2). The survey data helped inform select equipment saturation characteristics, primarily related to lighting and controls.

EIA regional data, as well as national studies on commercial energy consumption were used to inform consumption and equipment stock saturation levels.[8] These sources typically informed estimates of base equipment saturation for cooking, refrigeration, water heating, plug loads, and other miscellaneous end-uses.

[8] Examples of secondary research include: Energy Savings Potential RD&D Opportunities for Commercial Building Appliances. 2016. DOE and Energy Star Shipment Data.

For the industrial sector sensitivity, the analysis employed a top-down analysis at the end-use level. Accordingly, it was not critical to disaggregate the industrial sales at a measure-level. Instead, measures were developed to estimate savings at a total end-use level.

#### *4.1.2.4 Remaining Factor*

The remaining factor is the proportion of a given market segment that is not yet efficient and can still be converted to an efficient alternative. It is the inverse of the saturation of an energy efficient measure, prior to any adjustments. In this study, two key adjustments were made to recognize that the energy efficient saturation does not always fully represent the state of market transformation. First, while a percentage of installed measures may already be efficient, some customers may backslide (i.e. revert to standard technologies, or otherwise less efficient alternatives in the future, based on considerations like measure cost, availability and customer preferences).

Second, for measures categorized as market opportunity (i.e. replace-on-burnout), the GDS Team assumed that in some instances in which an efficient measure is already installed, the burnout or failure of those measures would be eligible for inclusion in the estimate of future savings potential. This adjustment assumes that some of the market is transformed, and no future savings potential exists, whereas there is also some portion of the market which is not transformed and could backslide without the intervention of a Kentucky Power program and an incentive.

### *4.1.3 Measure Characterization*

#### *4.1.3.1 Measure Lists*

The study's sector-level energy efficiency measure lists were informed by a range of sources including the Michigan Energy Measures Database ("MEMD"), the Illinois and Indiana technical reference manuals ("TRMs"), current Kentucky Power program offerings, and commercially viable emerging technologies, among others. Measure list development was a collaborative effort in which GDS developed draft lists that were shared with Kentucky Power and stakeholders. The final measure lists ultimately included in the study reflected the informed comments and considerations from the parties that participated in the measure list review process.

In total, GDS considered 303 measure types for this study. Several measures were included with multiple permutations to account for different specific market segments, such as different building types, efficiency levels, and replacement options. In total, GDS developed 2,067 measure permutations for this study. Each permutation was screened for cost-effectiveness under the Total Resource Cost ("TRC") Test. The parameters for cost-effectiveness under the TRC Test are discussed in detail later in Section 4.1.6.

**TABLE 4-2: NUMBER OF ELECTRIC MEASURES CONSIDERED FOR THE STUDY**

| | # of Measures | Total # of Measure Permutations |
|---|---|---|
| **Kentucky Power** | | |
| **Residential** | 154 | 811 |
| **Commercial** | 123 | 1,230 |
| **Industrial/Ag** | 26 | 26 |
| ***Total*** | ***303*** | ***2,067*** |

#### *4.1.3.2 Emerging Technologies*

GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart TVs, heat pump dryers and smart vents/sensors. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include building integrated energy management systems, advanced rooftop controls, variable refrigerant flow heat pumps, ozone commercial laundry, Q-Sync motors for refrigeration, advanced lighting controls, power distribution equipment upgrades, server virtualization, and escalator motor controls. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.

In addition to these specific technologies, GDS acknowledges that there could be future opportunities for new technologies as equipment standards improve and market trends occur. While this analysis does not make any explicit assumption about unknown future technologies, the methodology assumes that subsequent equipment replacement that occurs over the course of the 20-year study timeframe, and at the end of the initial equipment's useful life, will continue to achieve similar levels of energy savings, relative to improved baselines, at similar incremental costs.

#### *4.1.3.3 Assumptions & Sources*

A significant amount of data is needed to estimate the electric savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors. GDS utilized data specific to Kentucky Power to the extent possible. GDS used the most recent Kentucky Power program planning documents, the Michigan Energy Measures Database, and the Indiana and Illinois technical reference manuals for a large amount of the data requirements. Additional source documents included American Council for an Energy-Efficient Economy (ACEEE) research reports covering topics like emerging technologies.

***Measure Savings:*** GDS relied on the Illinois TRM and the MEMD to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. For custom measures and measures not included in the MEMD, GDS estimated savings from a variety of sources, including:

- IN TRM, and other regional/state TRMs
- Secondary sources such as the ACEEE, Department of Energy (DOE), EIA, ENERGY STAR©, and other technical potential studies

***Measure Costs:*** Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time.

GDS obtained measure cost estimates primarily from the Illinois TRM and the MEMD. GDS also used the following supplementary data sources:

- IN TRM, and other regional/state TRMs
- Secondary sources such as the ACEEE, ENERGY STAR, and NREL

Costs and savings for new construction and replace on burnout measures were calculated as the incremental difference between the code minimum equipment and the energy efficiency measure. This approach was utilized because the consumer must select an efficiency level that is at least the code minimum equipment when purchasing new equipment. The incremental cost is calculated as the difference between the cost of high efficiency and standard efficiency (code compliant) equipment. However, for retrofit or direct install measures, the measure cost was the "full" cost of the measure, as the baseline scenario assumes the consumer would not make energy efficiency improvements in the absence of a program. In general, the savings for retrofit measures are calculated as the difference between the energy use of the removed equipment and the energy use of the new high efficiency equipment (until the removed equipment would have reached the end of its useful life).

***Measure Life:*** Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the Illinois TRM and the MEMD, as well as:

- IN TRM, and other regional/state TRMs
- Manufacturer data
- Savings calculators and life-cycle cost analyses

All measure savings, costs, and useful life assumption sources are documented in the Appendices volume of this report.

#### *4.1.3.4 Treatment of Codes & Standards*

By law, the DOE is expected to review each national appliance standard every six years and publish either a proposed rule to update the standard or determine that no change to the existing standard is needed. The analysis is not intended to predict how or when energy codes and standards will change over time. Therefore, there are only limited known improvements to federal codes and standards to reasonably account for in this analysis.

#### *4.1.3.5 Net to Gross*

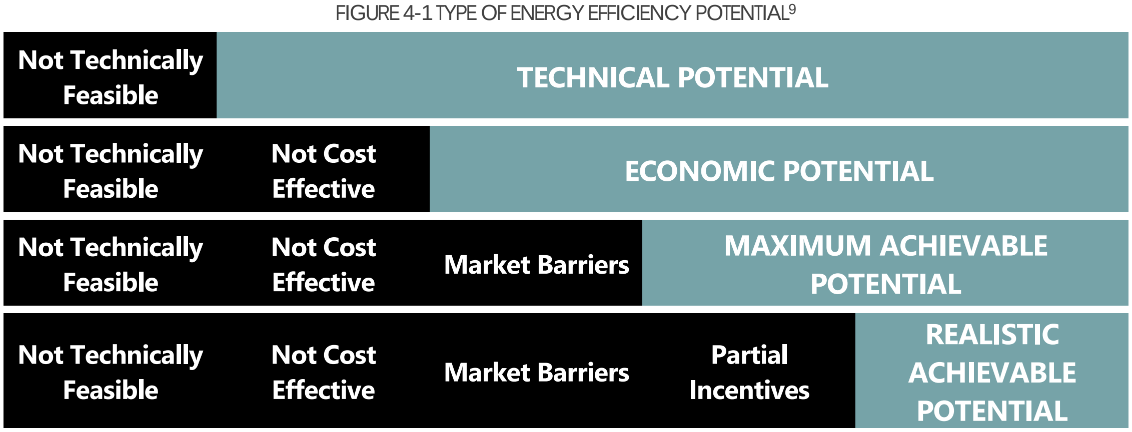
All estimates of technical, economic, and achievable potential, as well as measure level cost-effectiveness screening were conducted in terms of gross savings to reflect the absence of program design considerations in these phases of the analysis. The impacts of free-riders (participants who would have installed the high efficiency option in the absence of the program) and spillover customers (participants who install efficiency measures due to program activities, but never receive a program incentive) were considered in the development of program potential (Chapter 5).

### *4.1.4 Types of Potential*

This section reviews the types of potential analyzed in this report, as well as some key methodological considerations in the development of technical, economic, and achievable potential.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings can be realistically achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 4-1 illustrates the types of energy efficiency potential considered in this analysis.

FIGURE 4-1 TYPE OF ENERGY EFFICIENCY POTENTIAL[9]




9 Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1. Modified to depict the additional levels of achievable and program potential included in this study.

### *4.1.5 Technical Potential*

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Rather, retrofit opportunities were assumed to be replaced incrementally until 100% of stock was converted to the efficient measure over a period of no more than 15 years.

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 4-1 below. The C&I sector employs a similar analytical approach.

**EQUATION 4-1 CORE EQUATION FOR RESIDENTIAL SECTOR TECHNICAL POTENTIAL**

TECHNICAL POTENTIAL OF EFFICIENT MEASURES = *Total Number of Households* X *Base Case End Use Intensity (kWh/unit)* X *Saturation Share* X *Remaining Factor* X *Feasibility Factor* X *Savings Factor*

**Where…**

**Base Case Equipment End-Use Intensity** = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

**Saturation Share** = the fraction of the end-use electrical energy that is applicable for the efficient technology in a given market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

**Remaining Factor =** the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.

**Feasibility Factor** = (also functions as the applicability factor) the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install heat pump water heaters in all homes because of space limitations).

**Savings Factor** = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

#### *4.1.5.1 Competing Measures & Interactive Effects Adjustments*

GDS prevents double-counting of savings, and accounts for competing measures and interactive savings effects, through three primary adjustment factors:

***Baseline Saturation Adjustment.*** Competing measure shares are factored into the baseline saturation estimates. For example, nearly all homes can receive insulation. To account for this, GDS' analysis used multiple measure permutations that account for varying impacts of different heating/cooling combinations and baseline saturations were applied to reflect the proportions of households with each heating/cooling combination.

***Applicability Factor Adjustment.*** Combined measures into measure groups, where total applicability factor across measures is set to 100%. For example, homes cannot receive a programmable thermostat, connected thermostat, and smart thermostat. In general, the models assign the measure with the most savings the greatest applicability factor in the measure group, with competing measures picking up any remaining share.

***Interactive Savings Adjustment.*** As savings are introduced from select measures, the per-unit savings from other measures need to be adjusted (downward) to avoid over-counting. The analysis typically prioritizes market opportunity equipment measures (versus retrofit measures that can be installed at any time). For example, the savings from a smart thermostat are adjusted down to reflect the efficiency gains of installing an efficient air source heat pump.

### 4.1.6 Economic Potential

Economic potential refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC Test) as compared to conventional supply-side energy resources.

#### 4.1.6.1 TRC Test & Incentive Levels

The economic potential assessment included a screen for cost-effectiveness using the TRC Test at the measure level. In the Kentucky Power territory, the TRC Test considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and either incremental or full measure cost as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness.[10]

Apart from the low-income segment of the residential sector, all measures were required to have a TRC benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.

In the residential sector, incentives by program ranged from 50% to 100%. In the non-residential sector, incentives were assumed to represent 40% of the incremental measure cost. These incentive levels were selected so that the estimated incentive costs aligned with benchmarked data from EIA Form 861 reports filed by other national utilities related to incentive and non-incentive spending, as well as general industry experience.

#### 4.1.6.2 Avoided Costs

Avoided energy supply costs are used to assess the value of energy savings. Avoided cost values for electric energy, electric capacity, and avoided T&D were provided by Kentucky Power as part of an initial data request. Electric energy is based on an annual system marginal cost. For years outside of the avoided cost forecast timeframe, future year avoided costs are escalated by the rate of inflation.

Kentucky Power provided the GDS Team with monthly on and off-peak avoided energy costs. GDS used this data to create 8,760 avoided cost values for each forecast year. GDS then applied these avoided costs to the 8,760 savings from each measure based on assigned end-use load shapes[11] to determine the value of measures that save more energy during peak periods than those that might saving during off-peak periods. In addition, the avoided capacity and T&D avoided costs were applied to the estimated coincident peak demand savings for each measure.

### 4.1.7 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial,

[10] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. *Note: Non-incentive delivery costs are included in the assessment of achievable potential.*

[11] End-use load shapes were derived from building energy simulation models created by housing type and building type, specific to the KPCo service area.

customer awareness and WTP in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated three achievable potential scenarios:

- *MAP* estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.[12]
- *RAP* estimates achievable potential with Kentucky Power paying incentive levels (as a percentage of incremental measure costs) that are consistent with industry standard levels but is not constrained by any previously determined spending levels.
- *Program potential* provides an estimate of the savings potential that could be achieved with potential improvements to the existing electric energy efficiency program portfolio. The scenario leverages the RAP estimates as well as additional program design considerations.[13]

#### *4.1.7.1 Market Adoption Rates*

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific maximum adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

The initial step was to assess the long-term market adoption potential for energy efficiency technologies. Due to the wide variety of measures across multiple end-uses, GDS employed varied measure and end-use-specific ultimate adoption rates versus a singular universal market adoption curve. These long-term market adoption estimates were based on Kentucky Power-specific WTP market research. The Kentucky Power-specific research included questions to residential homeowners and nonresidential facility managers regarding their perceived willingness to purchase and install energy efficient technologies across various end uses and incentive/payback performance levels. This research is discussed in additional detail in Section 2.4.

One caveat to this approach is that the WTP adoption score is a simple function of incentive levels and/or payback performance. There are other factors that may influence a customer's willingness to purchase an energy efficiency measure. For example, increased marketing and education programs can have a critical impact on the success of energy efficiency programs. To recognize that the maximum achievable potential could increase current program awareness, we included an awareness adjustment factor to increase (by 15%) the estimated long-term adoption levels compared to the realistic achievable potential.

GDS utilized likelihood and willingness-to-participate data to estimate the long-term market adoption potential for both the maximum and realistic achievable scenarios. Table 4-3 presents the long-term market adoption rates at varied incentive levels used for the residential sector. Most end-uses are based on the WTP primary market research. Last, GDS adjusted the Kentucky Power-specific adoption curves to reflect observed differences in WTP between the income-qualified and market-rate customers.

**TABLE 4-3 RESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE INCENTIVE LEVELS**

| End Use | 0% Incentive | 25% Incentive | 50% Incentive | 75% Incentive | 100% Incentive |
|---|---|---|---|---|---|
| Heat/Cool Equip | 18% | 36% | 52% | 66% | 80% |
| Water Heat | 15% | 26% | 39% | 54% | 76% |
| Shell (insulation/sealing) | 14% | 23% | 36% | 50% | 74% |

[12] ibid.

[13] See Chapter 5 for more information about Program Potential

| End Use | 0% Incentive | 25% Incentive | 50% Incentive | 75% Incentive | 100% Incentive |
|---|---|---|---|---|---|
| Appliances | 19% | 32% | 50% | 63% | 80% |
| Thermostat DR | 21% | 33% | 47% | 58% | 64% |
| Solar | 6% | 14% | 29% | 50% | 75% |
| EVs | 4% | 8% | 22% | 35% | 52% |

Table 4-4 presents the long-term market adoption rates used in the nonresidential sector. Again, the adoption scores were primarily informed by the Kentucky Power-specific WTP research. GDS included a 20-year payback performance level to reflect reduced adoption rates for measures with extremely long payback performance levels. The 20-year payback performance was set to 2/3rd of the 10-year level. All remaining end-uses were typically mapped to the HVAC and/or Lighting end-uses.

**TABLE 4-4 NONRESIDENTIAL LONG-TERM MARKET ADOPTION RATES AT DISCRETE PAYBACK INTERVALS**

| End-Use | 20 Year Payback Period | 10 Year Payback Period | 5 Year Payback Period | 3 Year Payback Period | 1 Year Payback Period | 0 Year Payback Period |
|---|---|---|---|---|---|---|
| Lighting | 18% | 27% | 43% | 52% | 64% | 73% |
| HVAC | 16% | 24% | 38% | 50% | 60% | 66% |
| Refrigeration | 20% | 31% | 38% | 44% | 53% | 58% |
| Water Heat | 20% | 30% | 37% | 46% | 55% | 62% |
| Other | 18% | 27% | 43% | 52% | 64% | 73% |

GDS then estimated initial year adoption rates by reviewing the current saturation levels of efficient technologies and (if necessary) calibrating the estimates of 2023 annual potential to recent historical levels achieved by Kentucky Power's current DSM portfolio.

#### *4.1.7.2 Non-Incentive Costs*

Consistent with National Action Plan for Energy Efficiency (NAPEE) guidelines[14], utility non-incentive costs were included in the overall assessment of cost-effectiveness at the RAP scenario. Non-incentive costs were levels and set at:

- $0.0641 to $0.43 per first year kWh saved for non-low-income measures
- $0.95 per first year kWh saved for low-income program measures
- $0.080 per first year kWh saved for Commercial & Prescriptive Programs

Non-incentive costs were then escalated annually at the rate of inflation.[15]

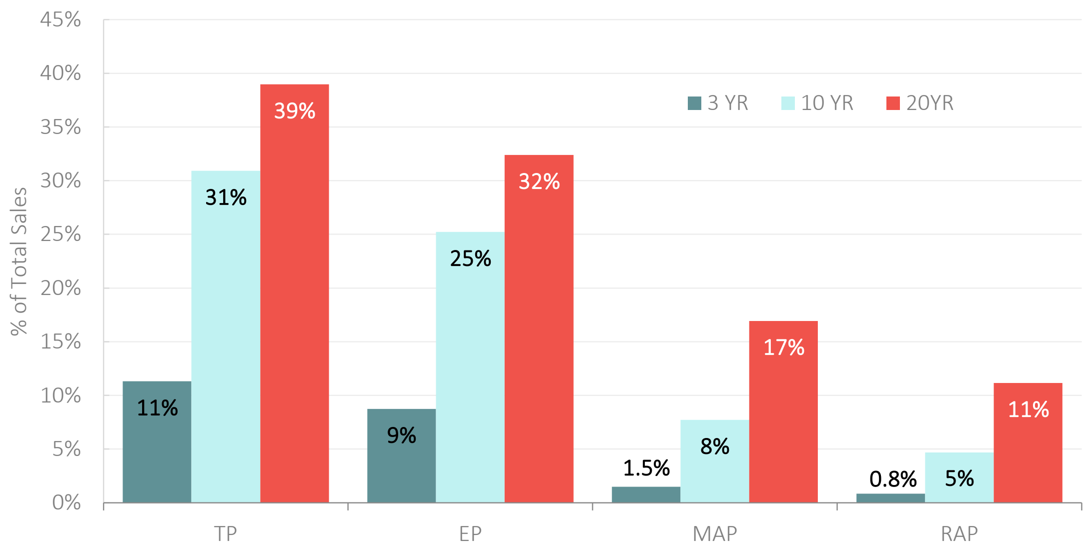
## 4.2 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL FINDINGS

Figure 4-2 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The cumulative annual 3-year technical potential is 11% of forecasted sales, and the economic potential is 9% of forecasted sales. The cumulative annual 3-year MAP is 1.8% and the RAP is 1.1%, as a

[14] National Action Plan for Energy Efficiency (2007). Guide for Conducting Energy Efficiency Potential Studies. Prepared by Optimal Energy. This study notes that economic potential only considers the cost of efficiency measures themselves, ignoring programmatic costs. Conversely, achievable potential should consider the non-measures costs of delivering programs. Pg. 2-4.
[15] As noted earlier in the report, measure costs and utility incentives were not escalated over the 20-year analysis timeframe to keep those costs constant in nominal dollars.

percentage of forecasted sales. Over the duration of the study timeframe the technical and economic potential rise to 39% and 32% of forecasted sales, respectively. This indicates that a large portion of the technical potential is cost-effective. The MAP and RAP rise respectively to 17% and 11% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 4-2: OVERVIEW OF RESIDENTIAL POTENTIAL




### *4.2.1 Technical/Economic Potential*

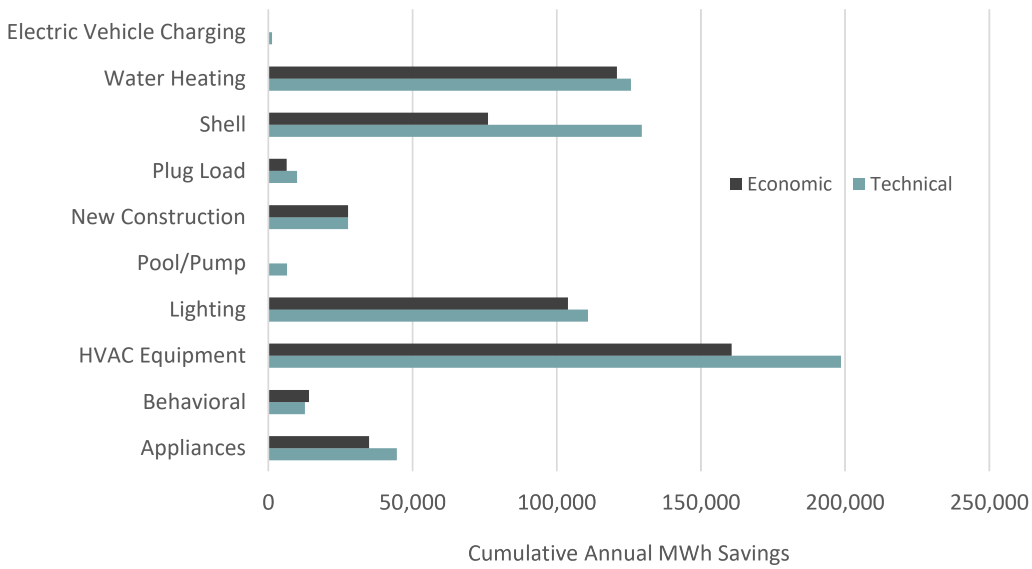
Table 4-5 provides cumulative annual technical and economic potential results across the 2024-2028 (Years 1-5) timeframe, as well as for 2033 (10th-year) and 2043 (20th-year). The technical potential is more than 331,000 MWh by 2028 and rises to more than 666,000 MWh by 2043. Economic potential rises to more than 257,000 MWh by 2028. Technical potential summer peak demand savings reaches 244 MW by 2043 and winter peak demand savings reaches approximately 92 MW by 2043.

TABLE 4-5 TECHNICAL & ECONOMIC RESIDENTIAL POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | | |
| **Technical** | 80,186 | 148,426 | 213,737 | 273,226 | 331,127 | 556,225 | 669,750 |
| **Economic** | 62,830 | 114,649 | 165,380 | 213,193 | 259,990 | 453,759 | 556,751 |
| **Summer Demand (MW)** | | | | | | | |
| **Technical** | 27.5 | 52.9 | 77.8 | 97.9 | 117.6 | 197.4 | 224.5 |
| **Economic** | 19.1 | 36.6 | 53.8 | 68.8 | 83.6 | 146.2 | 169.7 |
| **Winter Demand (MW)** | | | | | | | |
| **Technical** | 11.2 | 20.8 | 30.0 | 38.4 | 46.6 | 78.1 | 96.3 |
| **Economic** | 8.9 | 16.2 | 23.3 | 29.9 | 36.3 | 62.5 | 77.9 |

Figure 4-3 shows a comparison of the technical and economic potential (20-year) by end use. HVAC Equipment is the leading end-use among technical and economic potential, followed by Water Heating, Lighting, Building Shell and Appliances.

**FIGURE 4-3: 20-YR RESIDENTIAL TECHNICAL & ECONOMIC POTENTIAL, BY END-USE**




### *4.2.2 Achievable Potential*

Figure 4-4 provides the MAP and RAP across the 20-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The blue and orange lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual sales. The MAP rises to 17% by 2043, and the RAP rises to 11%.

**FIGURE 4-4: OVERVIEW OF RESIDENTIAL POTENTIAL – RAP 2043**

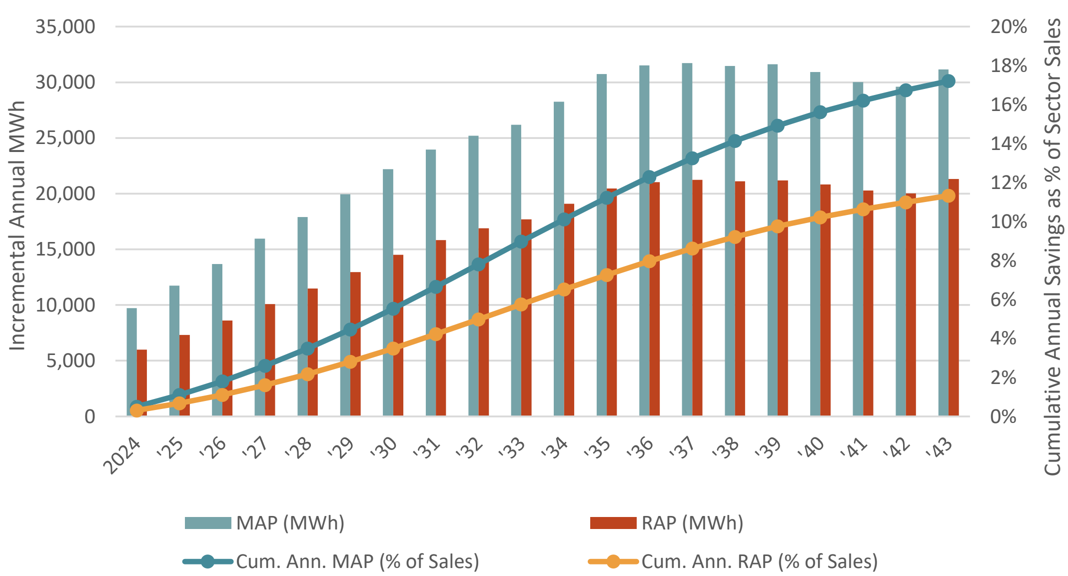



Figure 4-5 provides a breakdown of the RAP potential in 2043 across end-uses and home type/income type segments. HVAC Equipment is the leading end-use, accounting for 27% of the total. Water Heating, Shell, Lighting, Appliances, and Behavioral account for an additional 71% of the RAP. Among home types/income types, 29% of the potential is from the single-family ("SF") non-low-income ("NLI") segment, with an additional

35% of the potential from the SF-LI segment. The remaining 36% of the potential comes from the mobile home ("MH") and multifamily ("MF") segments across both all income types.

FIGURE 4-5: RESIDENTIAL POTENTIAL BY END-USE AND HOME/INCOME TYPE – RAP 2043

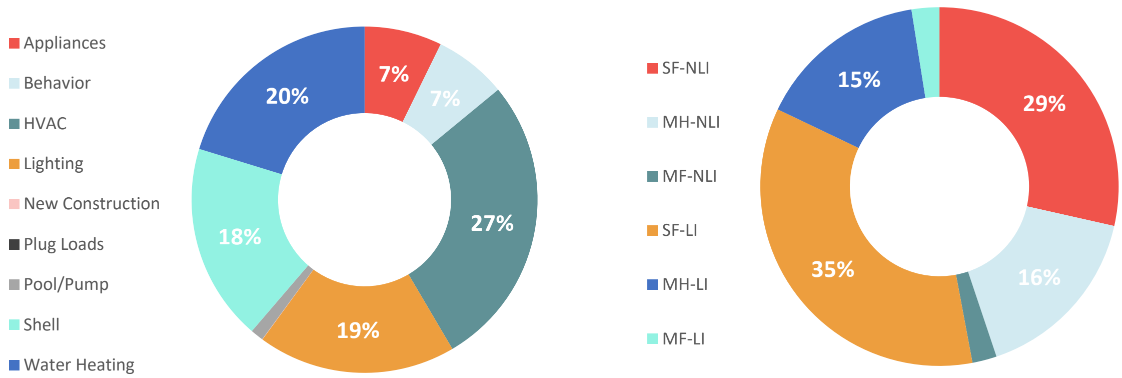



Table 4-6 provides incremental and cumulative annual energy and demand savings for MAP and RAP across the next five years as well as over the 10-yr and 20-yr time horizons. Incremental RAP energy savings range from 6,0600 MWh in 2024 to 21,000 MWh by 2043, and cumulative RAP energy savings rise to more than 194,000 MWh by 2043. Cumulative annual RAP summer peak demand reaches 68 MW by 2043 and cumulative annual RAP winter peak demand reaches 28 MW by 2043.

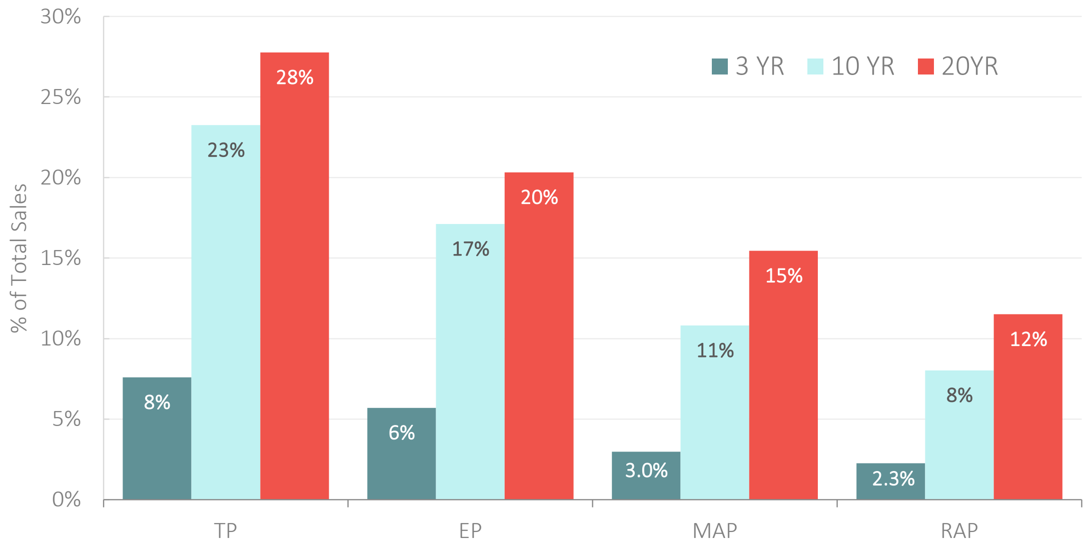
TABLE 4-6 RESIDENTIAL MAP & RAP POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2038 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Incremental Annual Energy (MWh)** | | | | | | | |
| **MAP** | 9,726 | 11,750 | 13,671 | 15,955 | 17,910 | 26,192 | 31,144 |
| **RAP** | 6,006 | 7,315 | 8,603 | 10,097 | 11,483 | 17,688 | 21,330 |
| **Incremental Annual Summer Peak Demand (MW)** | | | | | | | |
| **MAP** | 3.2 | 3.9 | 4.4 | 5.3 | 5.8 | 8.6 | 10.0 |
| **RAP** | 2.0 | 2.5 | 2.8 | 3.4 | 3.7 | 5.6 | 6.5 |
| **Incremental Annual Winter Peak Demand (MW)** | | | | | | | |
| **MAP** | 1.4 | 1.8 | 2.1 | 2.4 | 2.7 | 4.0 | 4.5 |
| **RAP** | 0.9 | 1.1 | 1.2 | 1.5 | 1.7 | 2.5 | 2.9 |
| **Cumulative Annual Energy (MWh)** | | | | | | | |
| **MAP** | 9,726 | 20,965 | 33,922 | 48,559 | 64,779 | 161,403 | 295,799 |
| **RAP** | 6,006 | 12,907 | 20,941 | 30,121 | 40,408 | 103,490 | 194,722 |
| **Cumulative Annual Summer Peak Demand (MW)** | | | | | | | |
| **MAP** | 3.2 | 7.1 | 11.4 | 16.2 | 21.5 | 53.6 | 100.3 |
| **RAP** | 2.0 | 4.4 | 7.2 | 10.3 | 13.7 | 35.3 | 67.9 |
| **Cumulative Annual Winter Peak Demand (MW)** | | | | | | | |
| **MAP** | 1.4 | 3.1 | 5.1 | 7.3 | 9.8 | 24.4 | 44.2 |
| **RAP** | 0.9 | 1.9 | 3.0 | 4.4 | 5.9 | 15.0 | 27.5 |

## 4.3 COMMERCIAL ENERGY EFFICIENCY POTENTIAL

Figure 4-6 provides the technical, economic, MAP and RAP results for the 3-year, 10-year, and 20-year timeframes. The cumulative annual 3-year technical potential is 8% of forecasted commercial sales, and the economic potential is 6% of forecasted commercial sales. The cumulative annual 3-year MAP is 3.0% and the RAP is 2.3%, as a percentage of forecasted commercial sales. Over the duration of the study timeframe the technical rises to 28% and economic potential rises to 20% of forecasted commercial sales. The MAP and RAP rise respectively to 15% and 12% of forecasted sales over the study timeframe. The gap between economic potential and MAP/RAP represents market barriers to prospective program participants, both financial and non-financial, to achieving the full amount of economic potential.

FIGURE 4-6: OVERVIEW OF COMMERCIAL POTENTIAL




### 4.3.1 Technical/Economic Potential

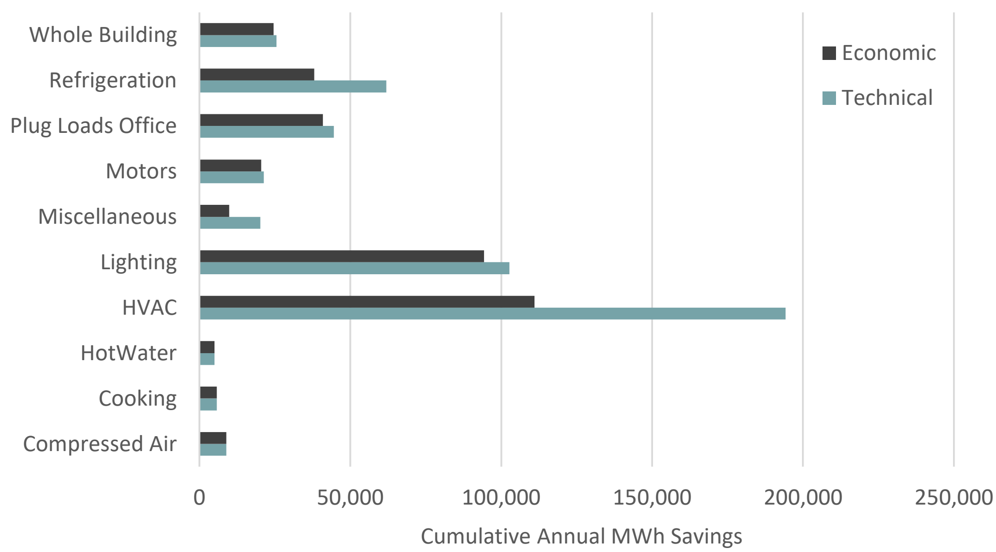
Table 4-7 provides cumulative annual technical and economic potential results across the 2024-2028 (Years 1-5) timeframe, as well as for 2033 (10th-year) and 2043 (20th-year). The technical potential is just above 230,000 MWh by 2028 and rises to more than 490,000 MWh by 2043. Economic potential rises to nearly 360,000 MWh by 2043 as well. Summer peak demand savings associated with technical potential reaches 101 MW by 2043 and winter peak demand savings reach approximately 48 MW by 2043.

TABLE 4-7 TECHNICAL & ECONOMIC COMMERCIAL POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2028 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Energy (MWh)** | | | | | | | |
| **Technical** | 43,541 | 90,256 | 138,295 | 186,119 | 232,533 | 416,505 | 490,105 |
| **Economic** | 32,833 | 67,950 | 103,914 | 139,507 | 173,783 | 306,552 | 358,764 |
| **Summer Demand (MW)** | | | | | | | |
| **Technical** | 7.7 | 16.3 | 25.3 | 34.6 | 43.7 | 83.1 | 101.4 |
| **Economic** | 4.8 | 9.9 | 15.3 | 20.8 | 26.1 | 47.2 | 55.8 |
| **Winter Demand (MW)** | | | | | | | |
| **Technical** | 4.5 | 9.3 | 14.2 | 19.0 | 23.6 | 41.4 | 47.9 |
| **Economic** | 3.7 | 7.7 | 11.7 | 15.7 | 19.6 | 34.5 | 40.6 |

Figure 4-7 shows a comparison of the technical and economic potential (20-year) by end use. HVAC and Lighting are the leading end-use among technical and economic potential. Plug Loads, Whole Building and Refrigeration savings also account for significant technical and economic potential.

**FIGURE 4-7: 20-YR COMMERCIAL TECHNICAL & ECONOMIC POTENTIAL, BY END-USE**




### *4.3.2 Achievable Potential*

Figure 4-8 provides the MAP and RAP across the 20-yr timeframe of the study. The green and red bars provide the respective incremental annual MAP and RAP in MWh per year energy savings. The green and orange lines provide the corresponding cumulative annual MAP and RAP as a percent of forecasted annual commercial sector sales. The MAP rises to 15% by 2043, and the RAP rises to 12% of forecasted commercial sales.

**FIGURE 4-8: OVERVIEW OF COMMERCIAL POTENTIAL – RAP 2043**

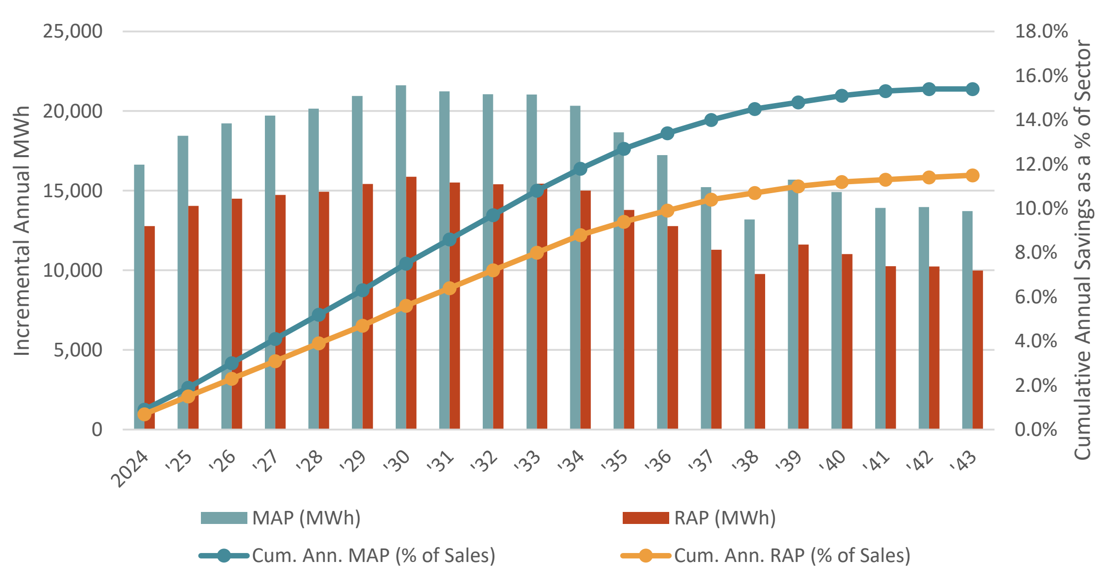


Figure 4-9 provides a breakdown of the RAP potential in 2043 across commercial end-uses and building type market segments.[16] In the RAP scenario, Lighting and HVAC account for over 50% of the potential. Across building types, Education (16%), Health (19%), Office (19%), and Retail (10%) account for about two-thirds of the potential. Assembly (3%), Food Sales (8%), Food Service (6%), Lodging (2%), and Warehouse (3%) combine for about one-quarter of the potential. The remaining "Other" building types represent 14% of the achievable potential.

FIGURE 4-9: COMMERCIAL POTENTIAL BY END-USE AND BUILDING TYPE – RAP 2043

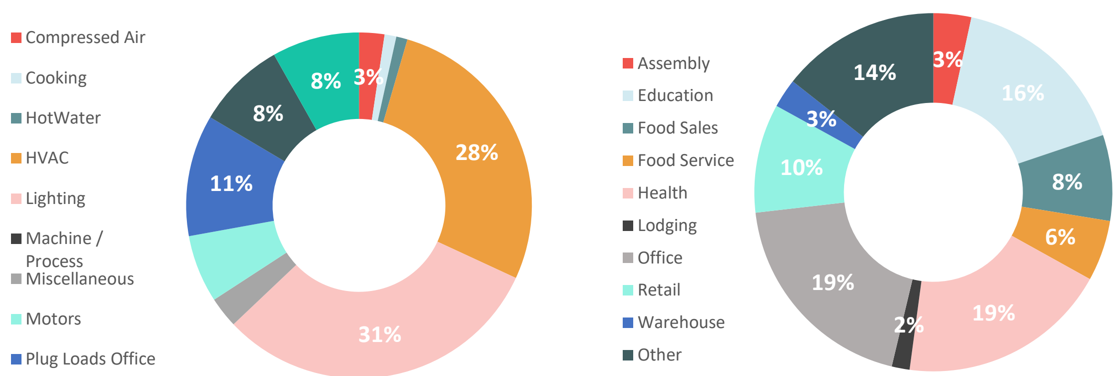



Table 4-8 provides incremental and cumulative annual commercial sector energy and demand savings for MAP and RAP across the next five years as well as over the 10-yr and 20-yr time horizons. Incremental RAP energy savings begin at roughly 12,800 MWh in 2024 followed by a steady increase over the remainder of the first decade of the timeframe, with savings trailing off in the second decade. Commercial lighting savings become increasingly difficult to sustain. Cumulative RAP energy savings rise to approximately 200,000 MWh by 2043. Cumulative annual RAP summer peak demand reaches 30 MW by 2043 and cumulative annual RAP winter peak demand reaches 23 MW by 2043.

TABLE 4-8 COMMERCIAL SECTOR MAP & RAP POTENTIAL

| | 2024 | 2025 | 2026 | 2027 | 2038 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Incremental Annual Energy (MWh)** | | | | | | | |
| **MAP** | 16,637 | 18,442 | 19,227 | 19,716 | 20,158 | 21,046 | 13,717 |
| **RAP** | 12,770 | 14,038 | 14,506 | 14,729 | 14,933 | 15,448 | 9,986 |
| **Incremental Annual Summer Peak Demand (MW)** | | | | | | | |
| **MAP** | 2.2 | 2.5 | 2.7 | 2.9 | 3.0 | 3.5 | 2.2 |
| **RAP** | 1.6 | 1.8 | 1.9 | 2.1 | 2.2 | 2.5 | 1.6 |
| **Incremental Annual Winter Peak Demand (MW)** | | | | | | | |
| **MAP** | 1.9 | 2.1 | 2.2 | 2.3 | 2.3 | 2.3 | 1.6 |
| **RAP** | 1.5 | 1.6 | 1.7 | 1.7 | 1.7 | 1.7 | 1.1 |
| **Cumulative Annual Energy (MWh)** | | | | | | | |
| **MAP** | 16,637 | 35,080 | 54,306 | 73,877 | 93,654 | 193,732 | 272,761 |
| **RAP** | 12,770 | 26,808 | 41,314 | 55,945 | 70,599 | 143,892 | 203,158 |

[16] Segments with less than 3% of total end-use or building type share do not display a data label (%) in pie-charts to improve readability of data.

| | 2024 | 2025 | 2026 | 2027 | 2038 | 2033 | 2043 |
|---|---|---|---|---|---|---|---|
| **Cumulative Annual Summer Peak Demand (MW)** | | | | | | | |
| **MAP** | 2.2 | 4.7 | 7.3 | 10.2 | 13.1 | 28.9 | 41.9 |
| **RAP** | 1.6 | 3.4 | 5.4 | 7.4 | 9.5 | 20.7 | 30.1 |
| **Cumulative Annual Winter Peak Demand (MW)** | | | | | | | |
| **MAP** | 1.9 | 4.0 | 6.3 | 8.5 | 10.8 | 22.1 | 31.0 |
| **RAP** | 1.5 | 3.1 | 4.8 | 6.5 | 8.2 | 16.6 | 23.4 |

# 5 PROGRAM DESIGN

The GDS Team conducted research and analysis to provide a recommendation for Kentucky Power to consider as potential improvements to their electric energy efficiency program portfolio. The primary objective is to expand energy efficiency for all customers with specific emphasis on low and moderate level income residential customers. The GDS Team combined market research of regional peer electric energy efficiency programs with the realistic potential outcomes from the marker potential assessment, in addition to current industry trends and best practices. This activity was not a comprehensive portfolio optimization analysis, instead priorities focused on energy efficiency offerings for all customers. There may be additional factors beyond the scope of this analysis that would make certain considerations presented here infeasible for Kentucky Power to pursue or concepts that need to be tested with actual market conditions.

## 5.1 ANALYSIS APPROACH

The GDS Team sought to gather insight into the latest industry trends and best practices by reviewing literature (e.g., industry association trends report, conference papers, government agency white papers, evaluation reports, and DSM plans), as well as data associated with the program portfolios offered by peer utilities. Outcomes from the MPS market research and initial modeling outputs, as well as input from prior Kentucky Power Commission Orders were considered in the analysis.

Guiding principles for the analysis were to:

- Identify cost-effective program opportunities (>1.0 TRC) that can deliver electric energy efficiency savings identified in the market potential study;
- Look for opportunities to shape a portfolio that exhibits characteristics identified as optimal for advancing the long-term success of energy efficiency markets; and
- Consider objectives Kentucky Power highlighted in its most recent DSM Plan filings.

### *5.1.1 Market Research*

As Kentucky Power's current program offerings are limited to a single residential low-income program coordinated through eastern Kentucky community action agencies, the GDS Team established a framework for determining new programs through industry best practices and benchmarking of regional energy-efficiency programs.

ACEEE's Utility Energy Efficiency Scorecard served as a key reference for identifying DSM program characteristics that look beyond the basic components of high impact energy savings and cost-effectiveness. ACEEE's Scorecard ranks DSM programs based on a variety of characteristics, recognizing that many factors shape the context for what a utility can offer, as well as the range of benefits a program may provide. Characteristics identified as important for utility energy efficiency portfolios include:[17]

- **Comprehensive** – serving the full spectrum of customer needs and end uses.
- **Responsive to market changes** - including emerging program areas and strategies that address major or growing end uses.
- **Innovative and engaging** - bringing in new technologies and strategies.
- **Simple, accessible, and hassle free** - to maximize customer participation.
- **Tailored** - to meet the unique needs of different customers and offering incentives at the most effective point in the supply chain for a given market.

[17] ACEEE 2020 Utility EE Scorecard, see "Practices of Leading Energy-Saving Utilities," p. 91.

The GDS Team selected several utilities for benchmarking comparison based on a combination of proximate geography and availability of granular measure-level data. For each of the comparison utilities, the GDS Team assembled data regarding program and measure offerings, incentives levels, and non-incentive program expenditures, as well as program cost-effectiveness. Data sources included DSM Plan filings, evaluation reports, program websites, and other sources where available. Energy-efficiency utility operated program research included:

- AEP Appalachian Power (West Virginia and Virginia)
- AEP Indiana Michigan (Indiana and Michigan)
- Duke Energy (Kentucky and North Carolina)
- East Kentucky Power Cooperative (Kentucky)
- Louisville Gas and Electric Company (Kentucky)
- First Energy West Penn Power (Pennsylvania)

The outcome of this market research was to identify candidate program archetypes with basic program go-to-market strategies and incentives, e.g. rebates, direct-install, marketplace, etc. for Kentucky Power's service territory.

### *5.1.2 Program Analysis*

The GDS Team utilized a program planning tool to construct a bottom-up portfolio to estimate savings forecasts, budgets, and cost effectiveness for the proposed Kentucky Power energy efficiency programs. Forecasts and parameters at the individual measure level are derived from the realistic achievable scenario outcomes including forecasted participation, energy savings, incremental costs, and incentives. Measures with a cost effectiveness results greater than 0.85 were identified as candidate measures for program archetype assignment. Individual measure permutations are bundled together prior to assignment to candidate program archetype. Program measure forecasts and incentives are reassessed within a program archetype. Program and portfolio cost effectiveness is assessed with final measures and expected program non-incentive costs. Budgets and participation are forecasted over five years. Additional considerations are given to non-administrative, or cross-cutting costs at the portfolio level when they cannot be attributed to a single program.

The program potential scenario simulates the expected program outcomes in forecasted years by including the following factors informed by best practice research:

- **Program Net-to-Gross values** (NTG)
    - Low-income programs utilize 1.0
    - New program offerings are defaulted to 0.8
- **Incentive levels and structures**
- **Program non-incentive costs (administrative)**
- **Historical participation and spending in the Targeted Energy Efficiency program**

The GDS Team recognizes the limitations of this secondary market research and analysis, understanding there could be factors which could limit the applicability of these considerations. The GDS Team would recommend that Kentucky Power gather program costs and measure details through detailed bottom-up labor estimates or market implementation contractors and vendors to validate these findings. Additionally, markets in the Kentucky Power service territory may not react immediately and/or the program may require time to mature operations; consequently, some of these forecasts should have cost effectiveness assessed after several years.

## 5.2 PROGRAM POTENTIAL RESULTS

Market research and accompanying analysis result in program potential as a subset of the cost-effective realistic achievable potential. Recommendations are based on general portfolio budget constraints, Kentucky Power applicable program concepts, and expected participation. A general 5-year portfolio plan was developed with focus on the three-year period 2024 – 2026, expecting to align with a regulatory DSM program filing period.[18]

### 5.2.1 Portfolio

Figure 5-1 and Figure 5-2 summarize the proposed program potential budgets and expected energy savings. It's notable that Kentucky Power's program budgets ranged between $250,000 - $300,000 from 2019 through 2022.

FIGURE 5-1: FIVE-YEAR ENERGY EFFICIENCY PORTFOLIO BUDGET EXPENDITURE FORECAST

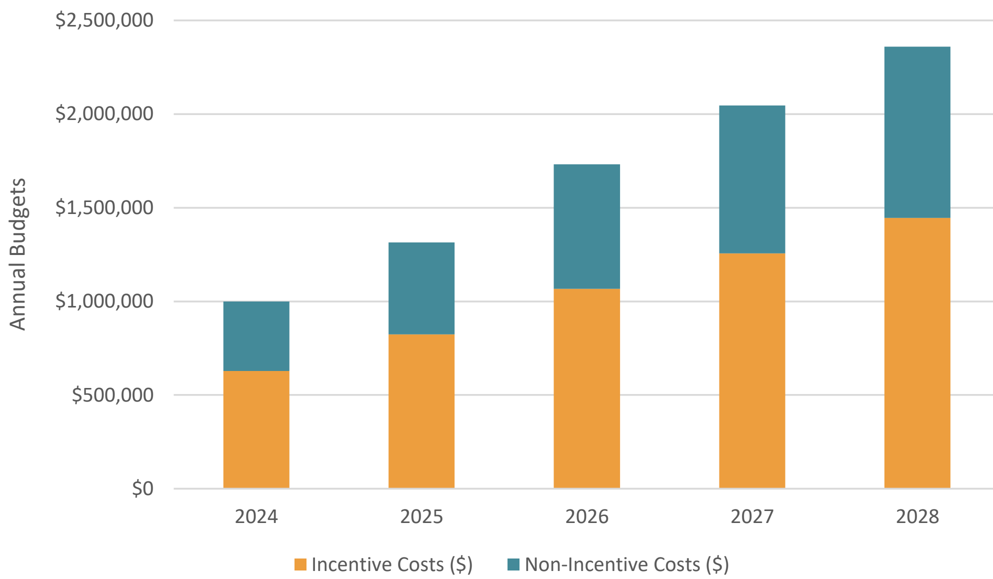
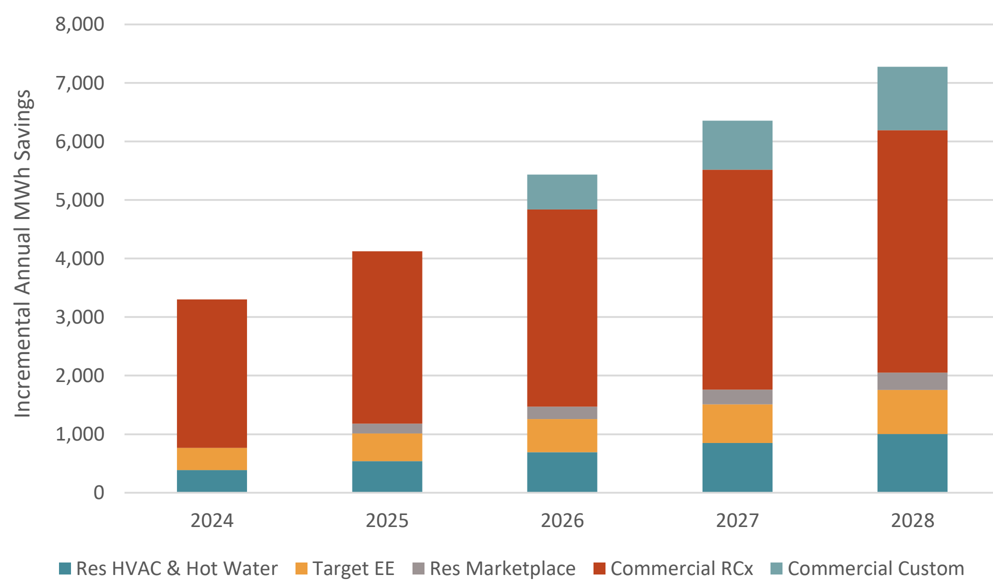



**FIGURE 5-2: FIVE-YEAR ENERGY EFFICIENCY PORTFOLIO ENERGY SAVINGS FORECAST**




[18] See Appendix E for annual participation data for each program.

Table 5-1 summarizes the forecasted three-year portfolio cost effectiveness outcomes.

**TABLE 5-1: THREE YEAR (2024-2026) PORTFOLIO COST EFFECTIVENESS SUMMARY**

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $9,883,554 |
| TRC Benefits | $16,799,884 |
| TRC Net Benefits ($) | $6,916,330 |
| TRC Net Benefits (Ratio) | 1.70[19] |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $6,271,880 |
| UCT Benefits | $13,529,965 |
| UCT Net Benefits ($) | $7,258,085 |
| UCT Net Benefits (Ratio) | 2.16 |

Where:

- **TRC Costs** = (Admin Costs) + (Incremental and O&M Costs)
- **TRC Benefits** = (Lifetime NPV Avoided Energy Costs) + (Tax Credits)

- **UCT Costs** = (Admin Costs) + (Incentive Payments); also could be considered program budget
- **UCT Benefits** = (Lifetime NPV Avoided Energy Costs)

### *5.2.2 Targeted Energy Efficiency Program*

The Targeted Energy Efficiency program is a program dedicated to low-income Kentucky Power customers which are eligible for Weatherization Assistance Program (WAP)[20] funds. The program promotes energy efficiency improvements in existing homes and provides financial incentives and assessments for implementing eligible energy efficiency measures. The program provides supplemental funding to the WAP for HVAC and other weatherization technologies through local community action agencies. Kentucky Power works with five (5) regional Community Action Programs as the company finds value in supporting the existing local energy-efficiency infrastructure and benefits associated with braiding United States Department of Energy (DOE) Weatherization Assistance Program (WAP) funds distributed through the Kentucky Housing Corporation (KHC)[21].

The Targeted Energy Efficiency program should increase spending in the next few years, seeking to double funding by program year three through the following actions:

- Increase payment amounts for completed energy audits with the intention to increase the number of completed audits and increase the comprehensiveness of energy audits.
- Increase incentives for replaced and upgraded HVAC equipment.

[19] Portfolio TRC cost-effectiveness reduces to 1.37 if tax-credits for residential technologies within the IRA are not considered.

[20] https://www.energy.gov/scep/wap/weatherization-assistance-program

[21] https://www.kyhousing.org/Partners/Developers/Single-Family/Weatherization-Assistance/Pages/default.aspx

It is understood that the Targeted Energy Efficiency program has operated for several years with consistent funding. There should be modest expectation on program growth with additional funds as program operations are not directly within Kentucky Power's influence.

**TABLE 5-2: THREE YEAR (2024-2026) TARGETED ENERGY EFFICIENCY COST EFFECTIVENESS SUMMARY**

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $2,187,452 |
| TRC Benefits | $1,809,509 |
| TRC Net Benefits ($) | ($377,943) |
| TRC Net Benefits (Ratio) | 0.83 |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $1,788,239 |
| UCT Benefits | $972,213 |
| UCT Net Benefits ($) | ($816,026) |
| UCT Net Benefits (Ratio) | 0.54 |

Included Measures:

- Air Source Heat Pump – replacement of furnace to SEER 14 heat pump,
- Air Source Heat Pump – efficiency SEER 16,
- Ductless Heat Pump – Energy Star compliant,
- Central Air Conditioner – minimum efficiency SEER 16
- Ductless Air Conditioner – Energy Star compliant,
- Energy and Home Audit reimbursement,
- Heat Pump Water Heater, and
- Incentive support for weatherization funds when not fully covered by WAP funds, including:
  - Attic Insulation
  - Hot Water Pipe Insulation, and
  - Air Sealing

### *5.2.3 Home Energy Improvement Program (HEIP)*

The Home Energy Improvement Program (HEIP) will promote energy efficiency improvements in existing homes and provide financial incentives and assessments for implementing eligible energy efficiency measures. The program provides customers, remodelers, and property owners with individual improvement options for HVAC and weatherization technologies. The program will largely offer incentives through rebates but may consider offering supplemental targeted energy audits. Additional funding towards audits can be considered starting in year 2 or year 3 to support program marketing and awareness and identify further potential savings opportunities. The HEIP will direct customers to the Targeted Energy Efficiency program when eligible customers seek whole-home renovations.

Included Measures:

- Air Source Heat Pump – efficient SEER 16 or greater,
- Ductless Heat Pump – Energy Star compliant,
- Air Conditioning only – efficient SEER 16 or greater,
- Smart Thermostats,

- Heat Pump Water Heater,
- Attic Insulation,
- Duct Insulation, and
- Air Sealing.

Table 5-3 summarizes the forecasted three-year portfolio cost effectiveness outcomes, with the three-year sum of annual incremental net energy savings at 1,618 MWh.

**TABLE 5-3: THREE-YEAR (2024-2026) HEIP COST EFFECTIVENESS SUMMARY**

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $1,765,704 |
| TRC Benefits | $4,692,105 |
| TRC Net Benefits ($) | $2,926,401 |
| TRC Net Benefits (Ratio) | 2.66[22] |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $1,334,223.55 |
| UCT Benefits | $2,384,465 |
| UCT Net Benefits ($) | $1,050,242 |
| UCT Net Benefits (Ratio) | 1.79 |

### *5.2.4 Marketplace Program*

The Marketplace Program is an on-line and easy-to-reach shopping platform for energy efficiency technologies found in customer homes, such as thermostats, smart plugs trips, and potentially small appliances. Kentucky Power anticipates operating this program with AEP and its subsidiary operating companies for a cost-effective program delivery approach. It is anticipated that this program will be introduced in the second year of the portfolio.

Included Measures:

- Smart Thermostats – wifi-enabled,
- Air Purifiers – Energy Star,
- Clothes Washers – Energy Star, and
- Plug Strips – Tier I and II (optional).

Table 5-4 summarizes the forecasted three-year portfolio cost effectiveness outcomes, with the three-year sum of annual incremental net energy savings at 375 MWh.

[22] Portfolio TRC cost-effectiveness reduces to 1.31 if tax-credits for residential technologies within the IRA are not considered.

TABLE 5-4: THREE-YEAR (2024-2026) MARKETPLACE COST EFFECTIVENESS SUMMARY

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $451,340 |
| TRC Benefits | $680,915 |
| TRC Net Benefits ($) | $229,575 |
| TRC Net Benefits (Ratio) | 1.51 |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $281,745 |
| UCT Benefits | $637,449 |
| UCT Net Benefits ($) | $355,704 |
| UCT Net Benefits (Ratio) | 2.26 |

### *5.2.5 Commercial Prescriptive Program*

Incentives offered through this program serve to reduce the incremental cost to upgrade to high-efficiency lighting equipment and controls over standard efficiency options for new and existing commercial customers. The program includes equipment with easily calculated savings, provides straightforward and easy participation for customers, and allows for reduced EM&V costs. The program should consider multiple participation options with energy audits and higher incentive levels available for small hard-to reach business customers.

Measure parameters may be refined during final program development, including establishing final eligibility criteria and measure-level project caps, if necessary. The incentive amounts for individual measures may be periodically adjusted to reflect current market conditions, changes in equipment costs or program economics, or to encourage participation during certain time periods, while maintaining the overall cost-effectiveness of the program. The structure of the Commercial Prescriptive Program also allows for straightforward expansion to incorporate additional cost-effective measures in the future with minimal design and implementation expenses.

Included Measures:

- LED Interior Fixtures,
- LED Exterior Fixtures,
- LED Linear Lamp Replacement,
- Lighting Controls,
- Smart Thermostats (year 2),
- Air Conditioning (year 2),
- Heat Pumps (year 2), and
- Energy Star Kitchen Equipment (year 3),

Table 5-5 summarizes the forecasted three-year portfolio cost effectiveness outcomes, with the three-year sum of annual incremental net energy savings at 8,851 MWh.

**TABLE 5-5: THREE-YEAR (2024-2026) COMMERCIAL PRESCRIPTIVE COST EFFECTIVENESS SUMMARY**

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $4,120,004 |
| TRC Benefits | $7,275,235 |
| TRC Net Benefits ($) | $3,155,230 |
| TRC Net Benefits (Ratio) | 1.77 |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $2,206,626 |
| UCT Benefits | $7,275,235 |
| UCT Net Benefits ($) | $5,068,608 |
| UCT Net Benefits (Ratio) | 3.30 |

### *5.2.6 Commercial Custom Program*

This program provides a platform for comprehensive energy efficiency projects in existing and new facilities that go beyond discrete measures and common, measure-level efficiency practices. The Commercial Custom Program provides incentives for efficiency improvements not included in the Commercial Prescriptive Program. It is anticipated that this program will be introduced in the third year of the portfolio due to additional complexity.

All program incentives should be based on the calculated, verified energy savings achieved for each project. The Commercial Custom Program does not define a specific list of eligible measures and bases participation on verifiable energy savings resulting from measures or system improvements implemented. Due to the complexity and variety of measures that could potentially be included, the Commercial Custom Program requires the applicant to submit calculations using industry-accepted methods for determining energy savings and appropriate baselines. These savings could be derived from capital improvements in equipment or from retro-commissioning (RCx).

Expected End-Uses:

- HVAC,
- Refrigeration, and
- Compressed Air.

Table 5-6 summarizes the forecasted three-year portfolio cost effectiveness outcomes, with the three-year sum of annual incremental net energy savings at 600 MWh assuming a start date in the third year.

TABLE 5-6: THREE-YEAR (2024-2026) NON-RESIDENTIAL CUSTOM COST EFFECTIVENESS SUMMARY

| Cost-effectiveness Parameter | Net Present Value (2023) |
|---|---|
| **Total Resource Cost (TRC)** | |
| TRC Costs | $1,359,053 |
| TRC Benefits | $2,342,120 |
| TRC Net Benefits ($) | $983,067 |
| TRC Net Benefits (Ratio) | 1.7 |
| **Utility Cost Test (UCT)** | |
| UCT Costs | $661,046 |
| UCT Benefits | $2,260,603 |
| UCT Net Benefits ($) | $1,599,557 |
| UCT Net Benefits (Ratio) | 3.42 |

### *5.2.7 Cross-Cutting Portfolio Items*

Finally, within the portfolio plan and considered within the cost-effectiveness outcomes listed above, the following cross-cutting costs should be and are included:

- Industry specific tracking, recording, and reporting information system
- A minimum of 5% for evaluation measurement and verification (EM&V) along with supporting planning activities. Within this portfolio recommendation, it is assumed that evaluation activities would occur within a three-cycle. Given the condition many programs will be new, it would be advisable to commence with process evaluation activities early in the program activity to identify improvement activities. Additionally, it would be advisable to conduct impact evaluation, included net-to-gross research, if appropriate, later in the three-year cycle to allow for program maturation.

## 5.3 KEY CONSIDERATIONS

The following considerations, developed with Kentucky Power, were instrumental in defining priorities for program and portfolio development and recommendations.

### *5.3.1 Support Community Action Groups*

Kentucky Power does not desire to de-fund or reduce funding to the regional Community Action Groups, as the company finds value in supporting the existing local energy-efficiency infrastructure. These action groups and associated contractors create benefits by braiding U.S. DOE Weatherization Assistance Program (WAP) funds with supporting funds from Kentucky Power. Additionally, Kentucky Power does not desire to create a competing or parallel DSM program that could create market confusion. Consequently, Kentucky Power will first increase funding for Community Action Group efficiency programs.

### *5.3.2 Expand Offerings for Low- and Moderate-Income Customers*

Additionally, it is recognized that additional funding for the Targeted Energy Efficiency program may not fully address the cost-effectiveness opportunity for low and moderate-income customers as program operations are not directly within Kentucky Power's influence. It is a priority to establish an easy-to-participate efficiency program directly supporting customers, remodelers, and property owners with individual improvement(s) options for HVAC and weatherization technologies. It is important for the program offering to address the large share of moderate-income residential customers that are marginally above the economic threshold for Weatherization funds. To reduce the opportunity for competition, the Home Energy Improvement Program (HEIP), should direct customers to the Targeted Energy Efficiency program when eligible customers seek whole-home renovations.

### 5.3.3 Add Offerings for Commercial Lighting

As noted earlier in this report, the commercial lighting end-use is the largest cost-effective opportunity for energy efficiency within Kentucky Power's service territory. A simple, easy to utilize, and cost-effective program archetype would be important to reach the largest program opportunity. Prescriptive programs have been and remain an important component of many DSM programs in North America with many of them having large shares of commercial lighting measures.

### 5.3.4 Monitor Inflation Reduction Act

Within the horizon of this study, it is expected that significant additional funding marked for energy efficiency and building electrification technologies for residential and non-residential customers will come through the Inflation Reduction Act[23] ("IRA"). As of the date of this report, many details of the IRA implementation are uncertain and unresolved. Of specific concern is a significant portion of funds are directed toward low-income customers (over $134 million in funds are allocated for low-income residential homes in Kentucky).[24] These funds are expected to be distributed through state energy offices, such as the Kentucky Housing Corporation, with the intention that customers can receive point-of-sale (POS) rebates. POS rebates are convenient for customers, but often introduce complexity for back-end tracking and validation systems. Additionally, all utility sponsored programs with incentives for overlapping technologies and measures will need to decide how to proceed in order to achieve maximum outcomes. In the best-case scenario, the added funds increase benefits for customers, contractors, and Kentucky Power. In worst case conditions, dual sources of incentives (Kentucky Power and IRA POS rebates) could create confusion, high free-ridership, and even fraudulent actions. It is recommended that KPCO monitor market conditions accordingly and adjust when prudent or practicable.

[23] https://www.irs.gov/inflation-reduction-act-of-2022

[24] https://www.energy.gov/articles/biden-harris-administration-announces-state-and-tribe-allocations-home-energy-rebate

# 6 DISTRIBUTED ENERGY RESOURCES POTENTIAL

As part of the overall potential modeling exercise, the GDS Team considered DERs as sources of behind-the-meter customer-sited solar photovoltaic generation. The DER potential study followed the same method as the energy efficiency potential study in that the DER analysis reviewed the opportunity for technical, economic, and achievable potential. We used the same forecast data as used in the energy efficiency study to assess DER potential. The analysis limited resources for this potential study to technologies that are behind-the-meter and owned by the customer and did not consider market potential for supply-side resources for the period 2024 to 2043.

## 6.1 APPROACH

The following section discusses the methods used to conduct the solar PV potential analysis. We detail approaches used to assess technical, economic, and achievable potential in the following steps:

- Technical and Economic Potential:
  - **Customer characterization/forecast disaggregation:** Using customer data, assess how many premises of each type and size exist in the Kentucky Power service territory. Using their historical energy usage and square footage, estimate the PV size/rooftop area capacity of each premise. Estimate how many solar PV systems are already installed in the Kentucky Power territory.
  - **Solar PV system modeling (technology):** Determine how much energy rooftop-mounted solar PV systems of different sizes and aspects generate in Kentucky, and at what times. Estimate system costs and benefits over the lifetime of the system.
- Achievable Potential:
  - **Scenarios:** Differentiate technical potential, business as usual, and a range of achievable scenarios according to varying incentive levels.
  - **Adoption rate modeling:** Based on the incentive levels and other attributes of market transformation, use Bass diffusion models to estimate the rate at which Kentucky Power customers would install solar PV systems under each scenario.

### *6.1.1 Technical Potential*

Photovoltaic systems utilize solar panels, a packaged collection of photovoltaic cells, to convert sunlight into electricity. A system is constructed with multiple solar panels, a DC/AC inverter(s), a racking system to hold the panels, and electrical system interconnections. These systems are often roof-mounted and face south-west, south, and/or, south-east.

The study analyzed the potential associated with roof-mounted systems installed on residential and non-residential sector buildings. For the non-residential sector, the analysis also estimated potential for ground mounted (or covered parking) systems for a few specific business types. The analysis included battery storage as an additional configuration with each solar PV system type; however, due to the uncertainty associated with battery dispatch schedules, potential battery generation is excluded from this analysis. As noted above, this study did not explore the market potential associated with utility-scale solar PV installations.

The approach to estimating technical potential required calculating the total square footage of suitable rooftop area within the Kentucky Power territory and calculating solar PV system generation based on building and regional characteristics. Technical potential is computed using Equation 6-1.

**EQUATION 6-1 SOLAR PV TECHNICAL POTENTIAL CALCULATION**

$$PV\ Technical\ Potential = \Sigma(Suitable\ Rooftop\ Square\ Footage\ \times PV\ System\ Generation\ per\ Sq.Ft.)$$

The two key parameters in Equation 6-1 were estimated based on multiple data sources relevant to eastern Kentucky. Methods for defining these parameters are discussed below. The GDS Team estimated total rooftop square footage using the forecast disaggregation analysis to characterize the residential and non-residential building stocks. The building stocks were characterized based on relevant parameters such as number of facilities, average number of floors, average premise consumption, and premise Energy Use Intensity (EUI). The GDS Team used these parameters to estimate the total rooftop square footage.

To estimate the fraction of the total roof area that is suitable for rooftop solar PV, the GDS Team relied on research completed by the Google Sunroof National Renewable Energy Laboratory (NREL). NREL has developed estimates of the portion of total rooftops across the country that are suitable for solar PV based on analysis of LIDAR data. NREL criteria for suitable roof area include:

- **Contiguous rooftop area size:** Rooftops with fewer than 10 square meters of contiguous roof area excluded.
- **Rooftop orientation (tilt and azimuth):** Northeast through northwest orientation and roof pitches greater than 60 degrees excluded.
- **Shading:** Roof areas that had a minimum solar exposure of less than 80% relative to an unshaded roof were excluded.

#### *6.1.1.1 Residential Premises*

Each residential customer account was classified into a premise type and size tier based on provided square footage where available and based on the average area for each premise type when square footage was unavailable. Three residential housing were modeled:

- Single Family Home
- Mobile Home
- Multifamily

Single Family houses accounted for 55% of annual energy use in 2022, with Mobile Homes accounting for another 31 percent. Table 6-1 summarizes how many accounts are in each premise type and how their size and energy use compare:

**TABLE 6-1 SUMMARY STATISTICS BY RESIDENTIAL PREMISE TYPE**

| Premise Type | Avg. Annual Energy Use (kWh) | Avg. Premise Size (sq. ft.) | Avg. Rooftop Usable Area (sq. ft.) |
|---|---|---|---|
| Single Family Houses | 15,834 | 1,433 | 1,447 |
| Mobile Home | 14,821 | 1,001 | 500 |
| Multifamily | 8,582 | 1,957 | 1,976 |
| **Total** | **14,879** | **1,340** | **1,190** |

#### *6.1.1.2 Non-Residential Premises*

Approximate square footage for each premise was derived by first mapping the SIC code for each account to the corresponding Commercial Buildings Energy Consumption Survey (CBECS) principal building activity. Then premise annual energy usage (kWh) was divided by the per-square-foot annual electricity consumption (energy use intensity, or EUI) estimated for each CBECS building type.

#### *6.1.1.3 Technologies*

The second key parameter – PV system generation – was estimated by developing standardized solar PV system configurations. These included system sizes for residential premises ranging from 3 to 25 kW (DC) and 5 to 2,000 kW (DC) for non-residential premises. Additionally, the GDS Team selected battery system sizes for each solar PV system size to dispatch energy for 2-4 hours.

The GDS Team relied on NREL's PVWatts[25] tools to estimate system generation for both residential and non-residential sited systems. These tools model PV power density based on site specific data from NREL's National Solar Renewable Database ("NSRDB") to estimate total solar irradiance in conjunction with PV system specifications. The PV system simulations were generated based on Ashland, Kentucky. The analysis assumptions are summarized in Table 6-2.

**TABLE 6-2 KEY ASSUMPTIONS IN SOLAR PV ANALYSIS**

| Parameter | Assumptions |
|---|---|
| Residential System Sizes (Nominal DC Capacity) | 3 kW, 5 kW, 7.5 kW, 10 kW, 25 kW |
| Non-Residential System Sizes (Nominal DC Capacity) | 5 kW, 10 kW, 15 kW, 20 kW, 25 kW, 50 kW, 100 kW, 250 kW, 500 kW, 1,000 kW, 2,000 kW |
| System Losses | 14.08% (NREL) |
| Tilt | 40° House / 25° Mobile Home / 15° Multi/Non-res |
| Azimuth | Varies by heading |
| Capacity Factor (weighted average) | House: 11.2% / Mobile: 20.3% / Multi/Non-res: 12.6% |
| DC to AC Size Ratio | 1.2 |
| Inverter Efficiency | 96% (micro-inverter) |
| Battery Round-Trip Efficiency | 85% |

For the residential sector, annual PV kWh estimates were developed for rooftops with each system size oriented to each of the four cardinal directions, then measures for each system were weighted by the orientation of actual rooftops in these zip codes. The estimated annual energy output, based on a weighted average of the values is 4,884 kWh for a 5 kW system installed in zip code 41102 (capacity factor = 11.2%). The same measure development process was used for all residential system sizes and premise types.

Five residential system sizes are included, ranging from 3-25 kW. Generation (kWh) for a given system is capacity (kW) multiplied by capacity factor for that system (based on location, aspect, tilt, and other key assumptions), multiplied by 8,760 hours. The smallest residential system modeled is 3 kW, which requires just over 200 sq. ft. of panel area, and the largest 25 kW, which requires about 1,681 sq. ft. of panel area. Each system is modeled with and without battery storage. Storage systems are limited to 5% of eligible premises based on technical feasibility. Mobile Home systems are limited to 3 and 5 kW, mounted at a 25-degree tilt, and do not include battery storage due to technical and space constraints.

Multifamily and non-residential solar PV systems were modeled similarly to residential systems with a few modifications for the typical attributes of these buildings. The 3 - 25 kW systems used in the residential sector

25 PVWatts estimates solar PV energy production and costs. Developed by the National Renewable Energy Laboratory. (NREL) http://pvwatts.nrel.gov/

are supplemented by larger system sizes up to 2 MW. Array tilt is 15 degrees due to mostly flat roofs present on commercial and industrial buildings.

### 6.1.2 Economic Potential

Economic potential represents the generation possible given full adoption of all cost-effective technologies. For the cost effectiveness analysis of solar PV, the GDS Team used a Total Resource Cost (TRC) hurdle of 1.0 to assess the TRC and relied on the same avoided energy and capacity costs used in the energy efficiency analysis. These avoided costs serve as the benefits while the costs are represented as the installation and O&M costs of the modeled solar technologies.

To estimate economic potential for solar PV, pertinent data on system costs were gathered along with calculated generation benefits to use in the benefit-cost analysis which was conducted at the measure level. The GDS Team relied on multiple data sources to determine the solar PV system costs for varying system sizes and configurations. System component costs are based on data included the NREL Q1 2021 Benchmarking report[26] which provided detailed cost information on modules, inverters (by technology), structural and electrical balance of system, supply chain, permitting-inspection-interconnection, marketing, overhead, and profit. Cost parameters adjusted these from a national level to Kentucky-specific values by using various market data provided by Energy Sage[27]. This analysis produced an estimated installation cost per watt installed which was applied to various system sizes to estimate total installed cost. Additionally, O&M costs were included that scale with system size. Finally, we included the impact of the federal investment tax credit (ITC) which is a base tax credit for commercial and residential systems starting in 2023.

In addition to modeling solar PV system costs, the GDS Team also estimated cost impacts for solar PV systems coupled with battery storage. As these systems are far less prevalent in both residential and commercial systems at the time of reporting, fewer published data on battery costs, balance of system costs, and maintenance were available. Moreover, the battery capacity is also variable based on the service need. Ultimately, multiple data sources were used to assume an overall capital cost per kWh based on a 3- or 4-hour battery for various measure permutations. O&M costs were largely defined by a ten-year amortized battery replacement cost.

**TABLE 6-3: ASSUMED SOLAR PV INSTALLATION COST (2023)**

| Sector | System Cost ($/ DC Watt) |
|---|---|
| Residential | $2.72 |
| Residential (Battery) | $3.20 - $6.70 |
| Business, roof mounted | $1.72 |
| Business, roof mounted (Battery) | $1.98 - $3.35 |
| Business, ground mounted | $1.72 |
| Business, ground mounted (Battery) | $1.84 |
| Operations & Maintenance | $16/kw/yr |
| Operations & Maintenance (with battery) | $29/kw/yr |

[26] U.S. Solar Photovoltaic System Cost Benchmark: Q1 2021. NREL, November 2021.
[27] Energysage Solar Marketplace Intel Report, H2 2021 – H1 2022.

### 6.1.3 Customer Adoption

While solar PV systems are not cost-effective according to the TRC test, Kentucky Power customers might install solar PV systems at their homes and businesses anyway. Consequently, a baseline, business-as-usual (BUA) forecast was developed for integration into the IRP modeling along with expected customer adoption for maximum and realistic potential for those system configurations and premise types where technologies could pass a cost-effectiveness threshold of TRC equal to 1.0 or greater.

Adoption rates are estimated using Bass diffusion modeling, whereby a simple differential equation is used to predict how a technology will be adopted in a market over time. Key assumptions include customer payback period, rates of innovation and imitation, along with the total eventual adopters or market size. The Bass diffusion model is provided below.

$$Nt = Nt\text{-}1 + p\,(m\text{-}Nt\text{-}1) + q\,Nt\text{-}1\,/m\,(m\text{-}Nt\text{-}1)$$

Where:

Nt = number of participants in a given year
p = coefficient of innovation
m = number of eventual adopters
q = coefficient of imitation

The parameters are based upon:
- Number of eventual adopters, willingness to participate, and market adoption data collected from Kentucky Power customers during this DSM Market Potential Study
- Coefficients are based upon the NREL dGen model[28] for the state of Kentucky, EIA DGPV interconnection and Census data

The three adoption scenarios for solar PV installations are described below:
- **Business-as-Usual ("BAU")**;
  - Systems are not incentivized beyond the existing income tax credit and continue at a pace similar to the rate of adoption in 2023
  - up to 6% market adoption for the residential sector
  - up to 5% market adoption for the non-residential sector
- **Realistic Achievable Potential**;
  - Adoption rate reflects a 50% incentive
  - up to 19% market adoption for the residential sector, and
  - up to 15% market adoption for the non-residential sector, and
- **Maximum Achievable Potential**;
  - Adoption rate reflects a 100% incentive
  - up to 68% market adoption for the residential sector, and
  - up to 26% market adoption for the non-residential sector, and

## 6.2 DER POTENTIAL FINDINGS

This section of the report presents the Technical, Economic, Achievable (MAP and RAP) potential for solar PV.

Table 6-4 summarizes the solar PV annual potential estimates for all sectors based on direct-current (DC) capacity while Table 6-5 and Table 6-6 summarize potential for the residential and non-residential sectors,

[28] https://www.nrel.gov/analysis/dgen/

respectively. It is notable that the non-residential sector potential sector is significantly less than residential potential. This difference is largely due to NREL coefficients.

TABLE 6-4 SUMMARY OF SOLAR PV DC CAPACITY MARKET POTENTIAL (ALL SECTORS)

| Year | Technical DC Capacity (MW) | Economic (MW) | MAP (MW) | RAP (MW) | BAU (MW) |
|---|---|---|---|---|---|
| 2027 | 3.2 | - | - | - | 1.7 |
| 2033 | 29.1 | - | - | - | 6.3 |
| 2043 | 475.8 | - | - | - | 36.4 |

TABLE 6-5 SUMMARY OF SOLAR PV DC CAPACITY MARKET POTENTIAL (RESIDENTIAL)

| Year | Scenario | Single-Family (MW) | Mobile Home (MW) | Multifamily (MW) |
|---|---|---|---|---|
| 2027 | Technical | 3.0 | 0.1 | 0.0 |
| 2033 | Technical | 27.3 | 0.7 | 0.4 |
| 2043 | Technical | 447.0 | 10.8 | 2.5 |
| 2027 | BAU | 1.6 | 0.0 | 0.0 |
| 2033 | BAU | 5.9 | 0.1 | 0.0 |
| 2043 | BAU | 34.6 | 0.8 | 0.2 |

TABLE 6-6 SUMMARY OF SOLAR PV DC CAPACITY MARKET POTENTIAL (NON-RESIDENTIAL)

| Year | Scenario | Non-Residential (MW) |
|---|---|---|
| 2027 | Technical | 0.1 |
| 2033 | Technical | 0.4 |
| 2043 | Technical | 5.9 |
| 2027 | BAU | 0.0 |
| 2033 | BAU | 0.0 |
| 2043 | BAU | 0.1 |

Table 6-7, Table 6-8, and Table 6-9 summarize solar PV potential above in energy metrics. The 2043 technical market potential for solar PV represents 9.0% of the 2043 energy sales forecast for all sectors. 2043 technical market potential for solar PV in the residential sector represents 27.0% of the 2043 energy sales forecast for the residential sector.

TABLE 6-7 SUMMARY OF SOLAR PV ENERGY MARKET POTENTIAL (ALL SECTORS)

| Year | Technical DC Capacity (MWh) | Economic (MWh) | MAP (MWh) | RAP (MWh) | BAU (MWh) |
|---|---|---|---|---|---|
| 2027 | 3,173 | - | - | - | 1,704 |
| 2033 | 28,724 | - | - | - | 6,179 |
| 2043 | 470,103 | - | - | - | 35,996 |

**TABLE 6-8 SUMMARY OF SOLAR PV ENERGY MARKET POTENTIAL (RESIDENTIAL)**

| Year | Scenario | Single-Family (MWh) | Mobile Home (MWh) | Multifamily (MWh) |
|---|---|---|---|---|
| **2027** | Technical | 2,982 | 130 | 44 |
| **2033** | Technical | 27,000 | 1,175 | 386 |
| **2043** | Technical | 441,655 | 19,227 | 2,757 |
| **2027** | BAU | 1,617 | 70 | 15 |
| **2033** | BAU | 5,865 | 255 | 53 |
| **2043** | BAU | 34,235 | 1,490 | 227 |

**TABLE 6-9 SUMMARY OF SOLAR PV ENERGY MARKET POTENTIAL (NON-RESIDENTIAL)**

| Year | Scenario | Non-Residential (MWh) |
|---|---|---|
| **2027** | Technical | 17,526 |
| **2033** | Technical | 162,771 |
| **2043** | Technical | 6,464,382 |
| **2027** | BAU | 1,235 |
| **2033** | BAU | 4,710 |
| **2043** | BAU | 43,715 |

Table 6-10 summarizes the cost effectiveness results for each technology and for the TRC cost-effectiveness perspective.

**TABLE 6-10 SUMMARY OF SOLAR PV COST-EFFECTIVENESS**

| Solar PV Technologies | TRC Test Range |
|---|---|
| Residential Roof-mounted (3 – 25 kW) | 0.6 |
| Residential Roof-mounted with Batteries (3 – 20 kW) | 0.4 – 0.5 |
| Non-residential Roof mounted (5 – 1,000 kW) | 0.8 |
| Non-residential Roof mounted with Batteries (5 – 1,000 kW) | 0.5 – 0.7 |

It is notable that no solar PV technologies pass cost-effectiveness screening under the TRC. This test is the primary cost-effectiveness criteria used to determine whether a utility sponsored program intervention is prudent. Low avoided costs serve as the primary driver behind the cost effectiveness results. At a technology level, the introduction of battery storage reduces cost effectiveness despite potential capacity benefit gains.

# APPENDIX A: GLOSSARY AND ACRONYMS

***ACEEE*** American Council for an Energy Efficient Economy

***Achievable Potential*** is the amount of energy that can realistically be saved given various market barriers.

***AMI*** Advanced metering infrastructure

***ASHP*** Air-source heat pump

***BAU*** Business-as-Usual

***Biz*** Business (used for potential modeling shorthand)

***CBECS*** Commercial Buildings Energy Consumption Survey

***C&I*** Commercial & industrial

***DER*** Distributed energy resources

***DOE*** Department of Energy

***DSM*** Demand-side Management

***EE*** Energy efficiency

***EIA*** Energy Information Administration

***Economic Potential*** refers to the subset of the technical potential that is economically cost-effective (based on screening with the TRC Test) as compared to conventional supply-side energy resources.

***ER*** Early replacement – describes a measure installed before the existing measure has failed.

***HEIP*** Home Energy Improvement Program

***HSPF*** Heating seasonal performance factor

***HVAC*** Heating, Ventilation and Air Conditioning

***kW*** kilowatt

***kWh*** kilowatt-hour

***LI*** low-income

***Maximum Achievable Potential*** achievable potential with 100% incentive levels

***MECS*** EIA Manufacturing Energy Consumption Survey

***MF*** multifamily home

***MH*** mobile/manufactured home

***MO*** Market opportunity – describes a measure installed when an existing technology has failed (used interchangeably with ROB)

***NLI*** Not-low-income

***NTG*** Net-to-gross ratio

***O&M*** Operation and maintenance

***Program Potential*** a subset of the cost-effective realistic achievable potential

***PV*** Photovoltaic

***RCx*** Retro-commissioning

***Realistic Achievable Potential*** achievable potential with incentive levels that are likely to be offered and optimistic long-term market adoption rates.

***Retro*** retrofit – describes a measure installed to improve the efficiency of the existing technology/condition

***ROB*** Replace-on-burnout – describes a measure installed when an existing technology has failed (used interchangeably with MO)

***SEER*** Seasonal energy efficiency ratio

***SF*** single-family home

***SIC*** Standard Industry Code

***Technical Potential*** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures.

***TRM*** Technical Reference Manual

***TRC*** Total Resource Cost (“TRC”) Test considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and either incremental or full measure cost as the cost.

***UCT*** Utility Cost Test

***WAP*** Weatherization Assistance Program

***WTP*** Willingness-to-Participate

# APPENDIX B: SENSITIVITIES

The GDS Team conducted sensitivity analyses on the base achievable scenario to assess the impacts of key input assumptions on the estimates of EE potential. The GDS Team coordinated with Kentucky Power to develop appropriate and reasonable sensitivity cases. The following were ultimately selected for the sensitivity analysis:

***Avoided Costs.*** Avoided costs are the primary benefit in assessing the cost-effectiveness of DSM measures. Higher avoided costs will likely result in additional measures passing the TRC cost-effectiveness screen, leading to greater savings potential, while lower avoided costs will decrease the cost-effectiveness of measures and lead to lower savings potential.

**High Sensitivities:** Increase avoided energy, generation capacity, and avoided T&D costs by 50%.
**Low Sensitivities**: Decrease avoided energy, generation capacity, and avoided T&D costs by 50%.
***Impacted Sectors:*** *Residential / Business*

***Large Customer Opt-Outs.*** The base case excludes sales and savings from all industrial customers as they are eligible to opt-out of contributing to Kentucky Power's energy efficiency funds. This sensitivity looks at the range of potential if all industrial customers were eligible to participate in future Kentucky Power C&I energy efficiency programs.

**High Sensitivity:** Include eligible industrial customers in analysis of future potential.
**Low Sensitivity**: n/a
***Impacted Sectors:*** *Business Only*

***Improved Technology Savings/Costs.*** This sensitivity was included to assess the impact of improved technology savings and/or reduced technology costs.

**High Sensitivity:** Assume program participation focuses on higher tier technologies regardless of current market acceptance; assume a 35% decrease in emerging technology/high tier equipment costs and incentives over the study horizon. For all other measures, reduced costs between 5%-20% based on current energy efficiency saturation assumptions. Shifted applicability to highest tier equipment (if cost-effective).
**Low Sensitivity**: n/a
***Impacted Sectors:*** *Residential / Business*

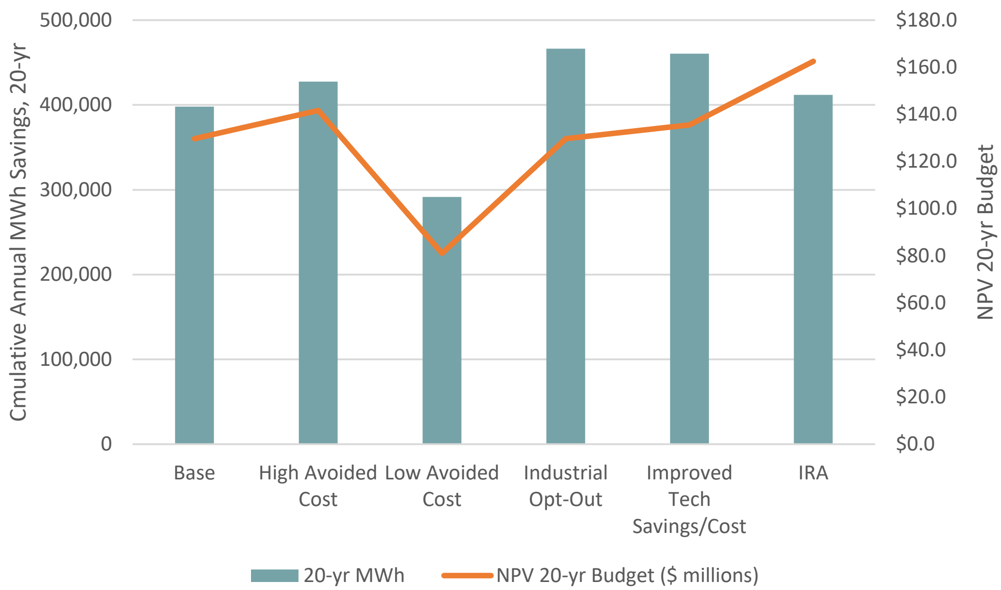
***Inflation Reduction Act.*** This sensitivity was included to assess the impact of an optimistic assumption regarding the widespread availability of tax credits associated with the Inflation Reduction Act.

**High Sensitivity:** Assume that every measure in the residential sector analysis for which there are relevant credits under the Inflation Reduction Act ("IRA") would receive the maximum amount available under the IRA. This credit acts as a benefit in the TRC Test calculation and allows more measures to pass the cost-effectiveness screening. The result is that additional HVAC, Building Shell and Water Heating measures pass the screening and are included in the potential.
**Low Sensitivity**: n/a
***Impacted Sectors:*** *Residential*

Figure A-1 provides the results of the sensitivity analysis compared to the base achievable potential scenario identified in the MPS. The blue bars show the 20-year cumulative annual MWh and the orange line provides the corresponding Net Present Value (NPV) of the 20-year budget (in $ millions).

The Low Avoided Cost sensitivity shows a significant drop in costs and savings compared to the Base Case. The high sensitivities are led by the Improved Tech Savings/Cost, followed by the Industrial Opt-Out, High Avoided Cost and Inflation Reduction Act sensitivities. These sensitivities help frame a proxy of the likely range of outcomes in the Realistic Achievable Scenario (Base Case).

**FIGURE B-1: SENSITIVITY RESULTS – SAVINGS AND NPV COSTS**



# APPENDIX C: NON-ENERGY BENEFITS

Non-energy Benefits (NEBs) are benefits that derive from energy efficiency beyond energy and cost savings. NEBs cover a wide range of possible impacts, including:

- Reduced environmental emissions,
- Water savings,
- Increased jobs or job skills,
- Indoor air quality health benefits,
- Increased safety,
- Reduced utility arrearages and shut offs,
- Improved comfort,
- Greater productivity,
- Reduced non-energy operating or maintenance costs,
- Increased energy resiliency.

NEBs may be an integral part of marketing energy efficiency, indicating that these benefits are meaningful to consumers. In other cases, the benefits may be to the utility system, environment, or general economy. Jurisdictions apply NEBs to cost-effectiveness tests, typically via an adder or multiplier to traditional energy and cost savings benefits.

In some cases, jurisdictions may quantify specific NEBs, while in others, a general multiplier is used to address hard-to-quantify NEBs or in cases where quantification research would be expensive. As examples, the State of Iowa uses a general 10 percent multiplier on energy benefits for its cost-effectiveness test, the State of Vermont includes an additional low-income benefits multiplier to capture additional value for low-income program participants, and Massachusetts spends considerable evaluation dollars to quantify specific dollar values for a variety of NEBs (e.g., health and safety NEBs for C&I energy efficiency, based on value per unit of energy savings).

The approach to energy efficiency cost-effectiveness may inform the types of NEBs that are appropriate to utilize. Under the Total Resource Cost (TRC) Test, NEBs considerations can impact a wide range of energy consumer and utility benefits, but do not extend to general societal benefits. The Societal Cost Test (SCT) expands the scope of NEBs to include TRC benefits and benefits that apply to society as a whole. The Utility Cost Test (UCT) would consider NEBs associated with a utility’s perspective. The Ratepayer Impact Measure (RIM) and Participant Cost Test (PCT) have narrow focuses, necessitating an inclusion of NEBs associated with their narrow perspectives.

**NEB Descriptions**

Below, we include brief descriptions of each type of NEB, starting with three quantifiable benefits, followed by others that are not as easily quantifiable.

*Reduced Environmental Emissions*

Energy efficiency reduces environmental emissions associated with energy consumption. These emissions may include carbon dioxide or emissions that fall under Clean Air Act regulations. NEB quantification could be based on avoiding the negative impacts of these emissions or on alternative compliance cost avoidance. In the Base Case, avoided environmental emissions include 5.6 million tons of $CO_2$, 7.5 million pounds of SOx, and 7.6 million pounds of NOx, over the lifetime of the measures installed during the study timeframe.

**TABLE C-1: AVOIDED ENVIRONMENTAL EMISSIONS BASED ON ACHIEVABLE POTENTIAL SCENARIOS**

| | Lifetime MWh | CO2 (tons) | SOx (lbs) | NOx (lbs) |
|---|---|---|---|---|
| MAP | 9,755,158 | 8,011,301 | 10,730,674 | 11,003,819 |
| RAP | 6,794,313 | 5,579,744 | 7,473,745 | 7,663,985 |
| Program | 3,051,455 | 2,505,969 | 3,356,601 | 3,442,042 |

*Water Savings*

For energy efficiency measures that save water, program participants may experience reduced water bills. Additionally, the water-energy nexus may allow for quantifying benefits to public water supply or treatment systems. Finally, in regions with water scarcity, water saving NEBs may provide benefits to society as a whole.

Total lifetime gallons of water saved associated with the cost-effective electric energy efficiency measures across the low, medium, and high scenarios ranged from 1.6 billion gallons to 6.1 billion gallons.

*Increased Jobs or Job Skills*

Implementation of energy efficiency programs creates jobs and job skills. This can be measured by the number of full-time equivalent ("FTE") employees needed to operate these programs. Using an estimated FTE cost of $150,000 in 2024, an annual inflation escalator across the study timeframe, and an assumption that 25% of non-incentive costs go towards education and outreach and other non-labor activities, we calculated an annual average of 2 FTEs in the Program Potential scenario, and an annual average of 24 FTEs and 35 FTEs in the RAP and MAP scenarios, respectively, across the 2024-2026 timeframe.

*Indoor Air Quality Health Benefits*

Energy efficiency measures that impact indoor air pollutants (e.g., improved ventilation or reduced infiltration, reduced carbon monoxide poisoning) can have a positive impact on participant health. NEBs related to improved health can impact the general quality of life, reduce employment absence, and reduce health care expenditures. Health and safety can also include reduced risks of heat or cold related injury or death.

*Increased Safety*

Energy efficiency measures can increase the safety of building occupants by avoiding potential injuries. One example is long-lived lighting measures that reduce risks associated with falling due to otherwise more frequent lamp replacement. Another example is avoiding risks associated with aging combustion equipment and fires or other negative health impacts. Additionally, new energy efficient equipment may be built to higher safety standards than older or base-standard equipment.

*Reduced Utility Arrearages or Shut-Offs*

By reducing energy costs, energy efficiency can make energy more affordable for limited-income households or struggling businesses. By reducing energy costs, utilities and ratepayers can avoid costs associated with arrearage management and shut-offs due to non-payment. The benefits for the program participant are maintaining valuable energy services and avoiding fees associated with arrearages and shut-offs.

*Improved Comfort*

Energy efficiency interventions can improve building occupant comfort, whether a home or business. While difficult to quantify the impact, home comfort has a linkage to health and general well-being and impacting the habitability and value of a home. Similar impacts to businesses can impact productivity, but generally improve employee morale and retention.

*Greater Productivity*

For C&I buildings or manufacturing plants, energy efficiency can improve productivity. Better lighting quality and improved comfort have an impact on employee productivity. For a manufacturing plant, energy efficient equipment can impact product quality, throughput, or innovation.

*Reduced Non-Energy Operating or Maintenance Costs*

The installation of new energy efficient equipment can reduce O&M costs associated with keeping equipment running. For example, an aging HVAC system may require more frequent servicing. An industrial plant may experience lower O&M or downtime.

*Increased Energy Resilience*

Energy efficiency can improve the resilience of communities faced with socioeconomic or natural disaster risk. Lowering energy demand can help maintain electric grid reliability to avoid or manage disruptions. Buildings may be better able to maintain building shell integrity or maintain occupant services during times of extreme weather.

While many of the above NEBs can be difficult to quantify for energy efficiency programs, some can be quantified. Those that are difficult to quantify can offer substantial value that may require assumptions regarding the relative value. The nature and scale of a NEB can vary from measure type to measure type, which can make direct application difficult. Nevertheless, there are policy options to allow for making assumptions to applying NEB values at a measure or portfolio level, allowing for capturing the value of NEBs in benefit-cost calculations.

# APPENDIX D: RESIDENTIAL ENERGY EFFICIENCY DETAIL

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1001 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | SF | NLI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 40% | PUR-1 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1002 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | SF | LI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 100% | PUR-2 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1003 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | MH | NLI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 40% | PUR-3 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1004 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | MH | LI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 100% | PUR-4 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1005 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | MF | NLI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 40% | PUR-5 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1006 | Appliances | ENERGY STAR Air Purifier | Residential Marketplace | MF | LI | MO | 533 | 57% | 303 | 0.03 | 9 | $92 | 100% | 100% | PUR-6 | 12% | 92% | 0.9 | 0.9 | 1.5 |
| 1007 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | SF | NLI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 40% | REF-1 | 100% | 70% | 0.8 | 0.8 | 0.8 |
| 1008 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | SF | LI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 100% | REF-2 | 100% | 70% | 0.8 | 0.8 | 0.8 |
| 1009 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | MH | NLI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 40% | REF-3 | 100% | 70% | 0.8 | 0.8 | 0.8 |
| 1010 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | MH | LI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 100% | REF-4 | 100% | 70% | 0.8 | 0.8 | 0.8 |
| 1011 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | MF | NLI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 40% | REF-5 | 100% | 58% | 0.7 | 0.7 | 0.8 |
| 1012 | Appliances | ENERGY STAR Refrigerator | Residential Marketplace | MF | LI | MO | 349 | 10% | 35 | 0.01 | 15 | $28 | 100% | 100% | REF-6 | 100% | 58% | 0.7 | 0.7 | 0.8 |
| 1013 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | SF | NLI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 40% | REF-1 | 100% | 70% | 0.8 | 0.8 | 0.3 |
| 1014 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | SF | LI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 100% | REF-2 | 100% | 70% | 0.8 | 0.8 | 0.3 |
| 1015 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | MH | NLI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 40% | REF-3 | 100% | 70% | 0.8 | 0.8 | 0.3 |
| 1016 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | MH | LI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 100% | REF-4 | 100% | 70% | 0.8 | 0.8 | 0.3 |
| 1017 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | MF | NLI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 40% | REF-5 | 100% | 58% | 0.7 | 0.7 | 0.3 |
| 1018 | Appliances | CEE Tier 2 Refrigerator | Residential Marketplace | MF | LI | MO | 349 | 15% | 52 | 0.01 | 15 | $112 | 100% | 100% | REF-6 | 100% | 58% | 0.7 | 0.7 | 0.3 |
| 1019 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | SF | NLI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 40% | REF-1 | 100% | 70% | 0.8 | 0.8 | 0.4 |
| 1020 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | SF | LI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 100% | REF-2 | 100% | 70% | 0.8 | 0.8 | 0.4 |
| 1021 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | MH | NLI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 40% | REF-3 | 100% | 70% | 0.8 | 0.8 | 0.4 |
| 1022 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | MH | LI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 100% | REF-4 | 100% | 70% | 0.8 | 0.8 | 0.4 |
| 1023 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | MF | NLI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 40% | REF-5 | 100% | 58% | 0.7 | 0.7 | 0.4 |
| 1024 | Appliances | CEE Tier 3 Refrigerator | Residential Marketplace | MF | LI | MO | 349 | 20% | 70 | 0.01 | 15 | $134 | 100% | 100% | REF-6 | 100% | 58% | 0.7 | 0.7 | 0.4 |
| 1025 | Appliances | Refrigerator Recycling | No program | SF | NLI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 40% | RR-1 | 21% | 0% | 0.7 | 0.3 | 1.9 |
| 1026 | Appliances | Refrigerator Recycling | No program | SF | LI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 100% | RR-2 | 21% | 0% | 0.8 | 0.6 | 1.9 |
| 1027 | Appliances | Refrigerator Recycling | No program | MH | NLI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 40% | RR-3 | 21% | 0% | 0.7 | 0.3 | 1.9 |
| 1028 | Appliances | Refrigerator Recycling | No program | MH | LI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 100% | RR-4 | 21% | 0% | 0.8 | 0.6 | 1.9 |
| 1029 | Appliances | Refrigerator Recycling | No program | MF | NLI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 40% | RR-5 | 4% | 0% | 0.6 | 0.2 | 1.9 |
| 1030 | Appliances | Refrigerator Recycling | No program | MF | LI | Recycle | 901 | 100% | 901 | 0.11 | 7 | $170 | 100% | 100% | RR-6 | 4% | 0% | 0.7 | 0.5 | 1.9 |
| 1031 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | SF | NLI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 40% | CW-1 | 100% | 73% | 0.8 | 0.8 | 1.0 |
| 1032 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | SF | LI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 100% | CW-2 | 100% | 73% | 0.8 | 0.8 | 1.0 |
| 1033 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | MH | NLI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 40% | CW-3 | 100% | 73% | 0.8 | 0.8 | 1.0 |
| 1034 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | MH | LI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 100% | CW-4 | 100% | 73% | 0.8 | 0.8 | 1.0 |
| 1035 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | MF | NLI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 40% | CW-5 | 67% | 49% | 0.6 | 0.6 | 1.0 |
| 1036 | Appliances | ENERGY STAR Clothes Washer | Residential Marketplace | MF | LI | MO | 590 | 24% | 140 | 0.02 | 14 | $87 | 100% | 100% | CW-6 | 67% | 49% | 0.7 | 0.6 | 1.0 |
| 1037 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | SF | NLI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 40% | CW-1 | 100% | 73% | 0.8 | 0.8 | 1.9 |
| 1038 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | SF | LI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 100% | CW-2 | 100% | 73% | 0.8 | 0.8 | 1.9 |
| 1039 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | MH | NLI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 40% | CW-3 | 100% | 73% | 0.8 | 0.8 | 1.9 |
| 1040 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | MH | LI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 100% | CW-4 | 100% | 73% | 0.8 | 0.8 | 1.9 |
| 1041 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | MF | NLI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 40% | CW-5 | 67% | 49% | 0.6 | 0.6 | 1.9 |
| 1042 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 2) | Residential Marketplace | MF | LI | MO | 590 | 43% | 255 | 0.03 | 14 | $85 | 100% | 100% | CW-6 | 67% | 49% | 0.7 | 0.6 | 1.9 |
| 1043 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | SF | NLI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 40% | CW-1 | 100% | 73% | 0.8 | 0.8 | 1.8 |
| 1044 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | SF | LI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 100% | CW-2 | 100% | 73% | 0.8 | 0.8 | 1.8 |
| 1045 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | MH | NLI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 40% | CW-3 | 100% | 73% | 0.8 | 0.8 | 1.8 |
| 1046 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | MH | LI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 100% | CW-4 | 100% | 73% | 0.8 | 0.8 | 1.8 |
| 1047 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | MF | NLI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 40% | CW-5 | 67% | 49% | 0.6 | 0.6 | 1.8 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1048 | Appliances | ENERGY STAR Clothes Washer (CEE Tier 3) | Residential Marketplace | MF | LI | MO | 590 | 47% | 276 | 0.04 | 14 | $99 | 100% | 100% | CW-6 | 67% | 49% | 0.7 | 0.6 | 1.8 |
| 1049 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | SF | NLI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 40% | DW-1 | 53% | 38% | 0.7 | 0.5 | 0.2 |
| 1050 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | SF | LI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 100% | DW-2 | 53% | 38% | 0.8 | 0.6 | 0.2 |
| 1051 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | MH | NLI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 40% | DW-3 | 53% | 38% | 0.7 | 0.5 | 0.2 |
| 1052 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | MH | LI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 100% | DW-4 | 53% | 38% | 0.8 | 0.6 | 0.2 |
| 1053 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | MF | NLI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 40% | DW-5 | 31% | 18% | 0.6 | 0.3 | 0.2 |
| 1054 | Appliances | ENERGY STAR Dishwasher | Residential Marketplace | MF | LI | MO | 307 | 12% | 37 | 0.00 | 11 | $76 | 100% | 100% | DW-6 | 31% | 18% | 0.7 | 0.5 | 0.2 |
| 1055 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | SF | NLI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 40% | DEH-1 | 25% | 38% | 0.7 | 0.5 | 7.1 |
| 1056 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | SF | LI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 100% | DEH-2 | 25% | 38% | 0.8 | 0.6 | 7.1 |
| 1057 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | MH | NLI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 40% | DEH-3 | 25% | 38% | 0.7 | 0.5 | 7.1 |
| 1058 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | MH | LI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 100% | DEH-4 | 25% | 38% | 0.8 | 0.6 | 7.1 |
| 1059 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | MF | NLI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 40% | DEH-5 | 25% | 18% | 0.6 | 0.3 | 7.2 |
| 1060 | Appliances | ENERGY STAR Dehumidifier | Residential Marketplace | MF | LI | MO | 1,095 | 12% | 134 | 0.03 | 10 | $10 | 100% | 100% | DEH-6 | 25% | 18% | 0.7 | 0.5 | 7.2 |
| 1061 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | SF | NLI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 40% | DEH-1 | 25% | 38% | 0.7 | 0.5 | 1.3 |
| 1062 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | SF | LI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 100% | DEH-2 | 25% | 38% | 0.8 | 0.6 | 1.3 |
| 1063 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | MH | NLI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 40% | DEH-3 | 25% | 38% | 0.7 | 0.5 | 1.3 |
| 1064 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | MH | LI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 100% | DEH-4 | 25% | 38% | 0.8 | 0.6 | 1.3 |
| 1065 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | MF | NLI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 40% | DEH-5 | 25% | 18% | 0.6 | 0.3 | 1.3 |
| 1066 | Appliances | ENERGY STAR Most Efficient Dehumidifier | Residential Marketplace | MF | LI | MO | 1,095 | 25% | 188 | 0.04 | 10 | $75 | 100% | 100% | DEH-6 | 25% | 18% | 0.7 | 0.5 | 1.3 |
| 1067 | Appliances | Dehumidifier Recycling | No program | SF | NLI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 40% | DR-1 | 6% | 0% | 0.7 | 0.3 | 16.3 |
| 1068 | Appliances | Dehumidifier Recycling | No program | SF | LI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 100% | DR-2 | 6% | 0% | 0.8 | 0.6 | 16.3 |
| 1069 | Appliances | Dehumidifier Recycling | No program | MH | NLI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 40% | DR-3 | 6% | 0% | 0.7 | 0.3 | 16.3 |
| 1070 | Appliances | Dehumidifier Recycling | No program | MH | LI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 100% | DR-4 | 6% | 0% | 0.8 | 0.6 | 16.3 |
| 1071 | Appliances | Dehumidifier Recycling | No program | MF | NLI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 40% | DR-5 | 6% | 0% | 0.6 | 0.2 | 16.4 |
| 1072 | Appliances | Dehumidifier Recycling | No program | MF | LI | Recycle | 1,000 | 100% | 1,000 | 0.00 | 7 | $20 | 100% | 100% | DR-6 | 6% | 0% | 0.7 | 0.5 | 16.4 |
| 1073 | Appliances | ENERGY STAR Freezer | Residential Marketplace | SF | NLI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 40% | FREEZER-1 | 59% | 28% | 0.7 | 0.4 | 5.5 |
| 1074 | Appliances | ENERGY STAR Freezer | Residential Marketplace | SF | LI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 100% | FREEZER-2 | 59% | 28% | 0.8 | 0.6 | 5.5 |
| 1075 | Appliances | ENERGY STAR Freezer | Residential Marketplace | MH | NLI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 40% | FREEZER-3 | 59% | 28% | 0.7 | 0.4 | 5.5 |
| 1076 | Appliances | ENERGY STAR Freezer | Residential Marketplace | MH | LI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 100% | FREEZER-4 | 59% | 28% | 0.8 | 0.6 | 5.5 |
| 1077 | Appliances | ENERGY STAR Freezer | Residential Marketplace | MF | NLI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 40% | FREEZER-5 | 27% | 22% | 0.6 | 0.4 | 5.5 |
| 1078 | Appliances | ENERGY STAR Freezer | Residential Marketplace | MF | LI | MO | 311 | 10% | 31 | 0.01 | 21 | $5 | 100% | 100% | FREEZER-6 | 27% | 22% | 0.7 | 0.5 | 5.5 |
| 1079 | Appliances | Freezer Recycling | No program | SF | NLI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 40% | FR-1 | 10% | 0% | 0.7 | 0.3 | 1.7 |
| 1080 | Appliances | Freezer Recycling | No program | SF | LI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 100% | FR-2 | 10% | 0% | 0.8 | 0.6 | 1.7 |
| 1081 | Appliances | Freezer Recycling | No program | MH | NLI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 40% | FR-3 | 10% | 0% | 0.7 | 0.3 | 1.7 |
| 1082 | Appliances | Freezer Recycling | No program | MH | LI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 100% | FR-4 | 10% | 0% | 0.8 | 0.6 | 1.7 |
| 1083 | Appliances | Freezer Recycling | No program | MF | NLI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 40% | FR-5 | 10% | 0% | 0.6 | 0.2 | 1.7 |
| 1084 | Appliances | Freezer Recycling | No program | MF | LI | Recycle | 722 | 100% | 722 | 0.09 | 8 | $170 | 100% | 100% | FR-6 | 10% | 0% | 0.7 | 0.5 | 1.7 |
| 1085 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | SF | NLI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 40% | DRYER-1 | 99% | 64% | 0.7 | 0.7 | 0.6 |
| 1086 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | SF | LI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 100% | DRYER-2 | 99% | 64% | 0.8 | 0.7 | 0.6 |
| 1087 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | MH | NLI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 40% | DRYER-3 | 99% | 64% | 0.7 | 0.7 | 0.6 |
| 1088 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | MH | LI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 100% | DRYER-4 | 99% | 64% | 0.8 | 0.7 | 0.6 |
| 1089 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | MF | NLI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 40% | DRYER-5 | 64% | 49% | 0.6 | 0.6 | 0.6 |
| 1090 | Appliances | ENERGY STAR Clothes Dryer | Residential Marketplace | MF | LI | MO | 769 | 21% | 160 | 0.02 | 11 | $152 | 100% | 100% | DRYER-6 | 64% | 49% | 0.7 | 0.6 | 0.6 |
| 1091 | Appliances | Heat Pump Dryer | Residential Marketplace | SF | NLI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 40% | DRYER-1 | 99% | 64% | 0.7 | 0.7 | 0.6 |
| 1092 | Appliances | Heat Pump Dryer | Residential Marketplace | SF | LI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 100% | DRYER-2 | 99% | 64% | 0.8 | 0.7 | 0.6 |
| 1093 | Appliances | Heat Pump Dryer | Residential Marketplace | MH | NLI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 40% | DRYER-3 | 99% | 64% | 0.7 | 0.7 | 0.6 |
| 1094 | Appliances | Heat Pump Dryer | Residential Marketplace | MH | LI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 100% | DRYER-4 | 99% | 64% | 0.8 | 0.7 | 0.6 |
| 1095 | Appliances | Heat Pump Dryer | Residential Marketplace | MF | NLI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 40% | DRYER-5 | 64% | 49% | 0.6 | 0.6 | 0.6 |
| 1096 | Appliances | Heat Pump Dryer | Residential Marketplace | MF | LI | MO | 769 | 49% | 378 | 0.14 | 11 | $405 | 100% | 100% | DRYER-6 | 64% | 49% | 0.7 | 0.6 | 0.6 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2001 | Behavioral | Home Energy Reports | Home Energy Reports | SF | NLI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 40% | HER-1 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2002 | Behavioral | Home Energy Reports | Home Energy Reports | SF | LI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 100% | HER-2 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2003 | Behavioral | Home Energy Reports | Home Energy Reports | MH | NLI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 40% | HER-3 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2004 | Behavioral | Home Energy Reports | Home Energy Reports | MH | LI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 100% | HER-4 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2005 | Behavioral | Home Energy Reports | Home Energy Reports | MF | NLI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 40% | HER-5 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2006 | Behavioral | Home Energy Reports | Home Energy Reports | MF | LI | MO | 14,827 | 1% | 148 | 0.02 | 1 | $0 | 100% | 100% | HER-6 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2007 | Behavioral | Home Energy Management System | No program | SF | NLI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 40% | HEMS-1 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2008 | Behavioral | Home Energy Management System | No program | SF | LI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 100% | HEMS-2 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2009 | Behavioral | Home Energy Management System | No program | MH | NLI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 40% | HEMS-3 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2010 | Behavioral | Home Energy Management System | No program | MH | LI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 100% | HEMS-4 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2011 | Behavioral | Home Energy Management System | No program | MF | NLI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 40% | HEMS-5 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2012 | Behavioral | Home Energy Management System | No program | MF | LI | MO | 14,827 | 3% | 476 | 0.05 | 5 | $90 | 100% | 100% | HEMS-6 | 100% | 0% | 0.9 | 0.7 | 1.4 |
| 2013 | Behavioral | AMI Data Portal | No program | SF | NLI | MO | 14,827 | 1% | 148 | 0.03 | 1 | $0 | 100% | 40% | AMI-1 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2014 | Behavioral | AMI Data Portal | No program | SF | LI | MO | 14,827 | 2% | 148 | 0.03 | 1 | $0 | 100% | 100% | AMI-2 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2015 | Behavioral | AMI Data Portal | No program | MH | NLI | MO | 14,827 | 2% | 148 | 0.03 | 1 | $0 | 100% | 40% | AMI-3 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2016 | Behavioral | AMI Data Portal | No program | MH | LI | MO | 14,827 | 2% | 148 | 0.03 | 1 | $0 | 100% | 100% | AMI-4 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2017 | Behavioral | AMI Data Portal | No program | MF | NLI | MO | 14,827 | 2% | 148 | 0.03 | 1 | $0 | 100% | 40% | AMI-5 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 2018 | Behavioral | AMI Data Portal | No program | MF | LI | MO | 14,827 | 2% | 148 | 0.03 | 1 | $0 | 100% | 100% | AMI-6 | 100% | 0% | 0.9 | 0.7 | 1.0 |
| 3001 | HVAC Equipment | ASHP Tune Up | No program | SF | NLI | Retrofit | 5,508 | 5% | 289 | 0.14 | 3 | $225 | 100% | 40% | HP TUNE-1 | 49% | 49% | 0.7 | 0.6 | 0.3 |
| 3002 | HVAC Equipment | ASHP Tune Up | Low Income | SF | LI | Retrofit | 5,508 | 5% | 474 | 0.50 | 3 | $225 | 100% | 100% | HP TUNE-2 | 49% | 49% | 0.8 | 0.6 | 0.5 |
| 3003 | HVAC Equipment | ASHP Tune Up | No program | MH | NLI | Retrofit | 5,508 | 5% | 474 | 0.50 | 3 | $225 | 100% | 40% | HP TUNE-3 | 49% | 49% | 0.7 | 0.6 | 0.5 |
| 3004 | HVAC Equipment | ASHP Tune Up | Low Income | MH | LI | Retrofit | 5,508 | 5% | 474 | 0.50 | 3 | $225 | 100% | 100% | HP TUNE-4 | 49% | 49% | 0.7 | 0.6 | 0.5 |
| 3005 | HVAC Equipment | ASHP Tune Up | No program | MF | NLI | Retrofit | 2,018 | 5% | 289 | 0.14 | 3 | $225 | 100% | 40% | HP TUNE-5 | 36% | 49% | 0.6 | 0.6 | 0.3 |
| 3006 | HVAC Equipment | ASHP Tune Up | Low Income | MF | LI | Retrofit | 2,018 | 5% | 289 | 0.14 | 3 | $225 | 100% | 100% | HP TUNE-6 | 36% | 49% | 0.6 | 0.6 | 0.3 |
| 3007 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 12% | 639 | 0.28 | 16 | $438 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3008 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 12% | 639 | 0.28 | 16 | $438 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.2 |
| 3009 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 12% | 639 | 0.28 | 16 | $438 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3010 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 12% | 639 | 0.28 | 16 | $438 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3011 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 19% | 389 | 0.20 | 16 | $438 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.8 |
| 3012 | HVAC Equipment | Air Source Heat Pump 16 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 19% | 389 | 0.20 | 16 | $438 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.8 |
| 3013 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 15% | 827 | 0.41 | 16 | $724 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.0 |
| 3014 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 15% | 827 | 0.41 | 16 | $724 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.0 |
| 3015 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 15% | 827 | 0.41 | 16 | $724 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.0 |
| 3016 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 15% | 827 | 0.41 | 16 | $724 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.0 |
| 3017 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 31% | 633 | 0.27 | 16 | $724 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3018 | HVAC Equipment | Air Source Heat Pump 17 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 31% | 633 | 0.27 | 16 | $724 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3019 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 22% | 1,200 | 0.49 | 16 | $963 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.0 |
| 3020 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 22% | 1,200 | 0.49 | 16 | $963 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.0 |
| 3021 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 22% | 1,200 | 0.49 | 16 | $963 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.0 |
| 3022 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 22% | 1,200 | 0.49 | 16 | $963 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.0 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3023 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 34% | 677 | 0.34 | 16 | $963 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.6 |
| 3024 | HVAC Equipment | Air Source Heat Pump 18 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 34% | 677 | 0.34 | 16 | $963 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.6 |
| 3025 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 23% | 1,268 | 0.66 | 16 | $1,204 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3026 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 23% | 1,268 | 0.66 | 16 | $1,204 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.9 |
| 3027 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 23% | 1,268 | 0.66 | 16 | $1,204 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3028 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 23% | 1,268 | 0.66 | 16 | $1,204 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3029 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 36% | 717 | 0.40 | 16 | $1,204 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.5 |
| 3030 | HVAC Equipment | Air Source Heat Pump 19 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 36% | 717 | 0.40 | 16 | $1,204 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.5 |
| 3031 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 24% | 1,344 | 0.68 | 16 | $1,444 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.8 |
| 3032 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 24% | 1,344 | 0.68 | 16 | $1,444 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.8 |
| 3033 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 24% | 1,344 | 0.68 | 16 | $1,444 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.8 |
| 3034 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 24% | 1,344 | 0.68 | 16 | $1,444 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.8 |
| 3035 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 37% | 752 | 0.45 | 16 | $1,444 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.5 |
| 3036 | HVAC Equipment | Air Source Heat Pump 20 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 37% | 752 | 0.45 | 16 | $1,444 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.5 |
| 3037 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 34% | 1,869 | 0.88 | 16 | $1,690 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3038 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 34% | 1,869 | 0.88 | 16 | $1,690 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.9 |
| 3039 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 34% | 1,869 | 0.88 | 16 | $1,690 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3040 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 34% | 1,869 | 0.88 | 16 | $1,690 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.9 |
| 3041 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 39% | 784 | 0.50 | 16 | $1,690 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.4 |
| 3042 | HVAC Equipment | Air Source Heat Pump 21 SEER - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 39% | 784 | 0.50 | 16 | $1,690 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.4 |
| 3043 | HVAC Equipment | Ground Source Heat Pump 20 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 16% | 896 | 0.53 | 25 | $11,871 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3044 | HVAC Equipment | Ground Source Heat Pump 20 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 16% | 896 | 0.53 | 25 | $11,871 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.1 |
| 3045 | HVAC Equipment | Ground Source Heat Pump 20 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 16% | 896 | 0.53 | 25 | $11,871 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3046 | HVAC Equipment | Ground Source Heat Pump 20 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 16% | 896 | 0.53 | 25 | $11,871 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3047 | HVAC Equipment | Ground Source Heat Pump 21.5 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 23% | 1,286 | 0.64 | 25 | $11,871 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3048 | HVAC Equipment | Ground Source Heat Pump 21.5 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 23% | 1,286 | 0.64 | 25 | $11,871 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.1 |
| 3049 | HVAC Equipment | Ground Source Heat Pump 21.5 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 23% | 1,286 | 0.64 | 25 | $11,871 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3050 | HVAC Equipment | Ground Source Heat Pump 21.5 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 23% | 1,286 | 0.64 | 25 | $11,871 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.1 |
| 3051 | HVAC Equipment | Ground Source Heat Pump 23.5 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 30% | 1,640 | 0.76 | 25 | $11,871 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.2 |
| 3052 | HVAC Equipment | Ground Source Heat Pump 23.5 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 30% | 1,640 | 0.76 | 25 | $11,871 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.2 |
| 3053 | HVAC Equipment | Ground Source Heat Pump 23.5 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 30% | 1,640 | 0.76 | 25 | $11,871 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.2 |
| 3054 | HVAC Equipment | Ground Source Heat Pump 23.5 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 30% | 1,640 | 0.76 | 25 | $11,871 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.2 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3055 | HVAC Equipment | Ground Source Heat Pump 29 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 38% | 2,068 | 1.02 | 25 | $11,871 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 0.2 |
| 3056 | HVAC Equipment | Ground Source Heat Pump 29 SEER - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 38% | 2,068 | 1.02 | 25 | $11,871 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 0.2 |
| 3057 | HVAC Equipment | Ground Source Heat Pump 29 SEER - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 38% | 2,068 | 1.02 | 25 | $11,871 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 0.2 |
| 3058 | HVAC Equipment | Ground Source Heat Pump 29 SEER - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 38% | 2,068 | 1.02 | 25 | $11,871 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 0.2 |
| 3059 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 9% | 485 | 0.25 | 15 | $267 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.5 |
| 3060 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 9% | 485 | 0.25 | 15 | $267 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.5 |
| 3061 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 9% | 485 | 0.25 | 15 | $267 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.5 |
| 3062 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 9% | 485 | 0.25 | 15 | $267 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.5 |
| 3063 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 9% | 187 | 0.17 | 15 | $267 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3064 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 9% | 187 | 0.17 | 15 | $267 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3065 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 12% | 653 | 0.44 | 15 | $267 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 2.2 |
| 3066 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 12% | 653 | 0.44 | 15 | $267 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 2.2 |
| 3067 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 12% | 653 | 0.44 | 15 | $267 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 2.2 |
| 3068 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 12% | 653 | 0.44 | 15 | $267 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 2.2 |
| 3069 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 13% | 269 | 0.30 | 15 | $267 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 1.0 |
| 3070 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 13% | 269 | 0.30 | 15 | $267 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 1.0 |
| 3071 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 17% | 960 | 0.60 | 15 | $533 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.6 |
| 3072 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 17% | 960 | 0.60 | 15 | $533 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.6 |
| 3073 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 17% | 960 | 0.60 | 15 | $533 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.6 |
| 3074 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 17% | 960 | 0.60 | 15 | $533 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.6 |
| 3075 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 19% | 388 | 0.40 | 15 | $533 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3076 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 19% | 388 | 0.40 | 15 | $533 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.7 |
| 3077 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 5,508 | 19% | 1,072 | 0.73 | 15 | $820 | 100% | 40% | HP-1 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3078 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | Low Income | SF | LI | MO | 5,508 | 19% | 1,072 | 0.73 | 15 | $820 | 100% | 100% | HP-2 | 49% | 56% | 0.8 | 0.6 | 1.2 |
| 3079 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 5,508 | 19% | 1,072 | 0.73 | 15 | $820 | 100% | 40% | HP-3 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3080 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | Low Income | MH | LI | MO | 5,508 | 19% | 1,072 | 0.73 | 15 | $820 | 100% | 100% | HP-4 | 49% | 56% | 0.7 | 0.6 | 1.2 |
| 3081 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,018 | 22% | 443 | 0.49 | 15 | $820 | 100% | 40% | HP-5 | 36% | 56% | 0.7 | 0.6 | 0.6 |
| 3082 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Heat pump baseline | Low Income | MF | LI | MO | 2,018 | 22% | 443 | 0.49 | 15 | $820 | 100% | 100% | HP-6 | 36% | 56% | 0.7 | 0.6 | 0.6 |
| 3083 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 59% | 6,431 | 0.28 | 16 | $438 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 10.2 |
| 3084 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 59% | 6,431 | 0.28 | 16 | $438 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 10.2 |
| 3085 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 59% | 6,431 | 0.28 | 16 | $438 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 10.2 |
| 3086 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 59% | 6,431 | 0.28 | 16 | $438 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 10.2 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3087 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 59% | 1,959 | 0.09 | 16 | $438 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 3.1 |
| 3088 | HVAC Equipment | Air Source Heat Pump 16 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 59% | 1,959 | 0.09 | 16 | $438 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 3.1 |
| 3089 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 61% | 6,574 | 0.41 | 16 | $724 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 6.4 |
| 3090 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 61% | 6,574 | 0.41 | 16 | $724 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 6.4 |
| 3091 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 61% | 6,574 | 0.41 | 16 | $724 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 6.4 |
| 3092 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 61% | 6,574 | 0.41 | 16 | $724 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 6.4 |
| 3093 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 61% | 2,002 | 0.13 | 16 | $724 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.9 |
| 3094 | HVAC Equipment | Air Source Heat Pump 17 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 61% | 2,002 | 0.13 | 16 | $724 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.9 |
| 3095 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 67% | 7,275 | 0.49 | 16 | $963 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 5.3 |
| 3096 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 67% | 7,275 | 0.49 | 16 | $963 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 5.3 |
| 3097 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 67% | 7,275 | 0.49 | 16 | $963 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 5.3 |
| 3098 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 67% | 7,275 | 0.49 | 16 | $963 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 5.3 |
| 3099 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 67% | 2,216 | 0.15 | 16 | $963 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.6 |
| 3100 | HVAC Equipment | Air Source Heat Pump 18 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 67% | 2,216 | 0.15 | 16 | $963 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.6 |
| 3101 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 65% | 7,085 | 0.66 | 16 | $1,204 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3102 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 65% | 7,085 | 0.66 | 16 | $1,204 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 4.2 |
| 3103 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 65% | 7,085 | 0.66 | 16 | $1,204 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3104 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 65% | 7,085 | 0.66 | 16 | $1,204 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3105 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 65% | 2,158 | 0.20 | 16 | $1,204 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3106 | HVAC Equipment | Air Source Heat Pump 19 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 65% | 2,158 | 0.20 | 16 | $1,204 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3107 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 64% | 6,954 | 0.68 | 16 | $1,444 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 3.4 |
| 3108 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 64% | 6,954 | 0.68 | 16 | $1,444 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 3.4 |
| 3109 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 64% | 6,954 | 0.68 | 16 | $1,444 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 3.4 |
| 3110 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 64% | 6,954 | 0.68 | 16 | $1,444 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 3.4 |
| 3111 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 64% | 2,118 | 0.21 | 16 | $1,444 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.0 |
| 3112 | HVAC Equipment | Air Source Heat Pump 20 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 64% | 2,118 | 0.21 | 16 | $1,444 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.0 |
| 3113 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 79% | 8,604 | 0.88 | 16 | $1,690 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 3.6 |
| 3114 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | Low Income | SF | LI | MO | 10,861 | 79% | 8,604 | 0.88 | 16 | $1,690 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 3.6 |
| 3115 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 79% | 8,604 | 0.88 | 16 | $1,690 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 3.6 |
| 3116 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | Low Income | MH | LI | MO | 10,861 | 79% | 8,604 | 0.88 | 16 | $1,690 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 3.6 |
| 3117 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 79% | 2,621 | 0.27 | 16 | $1,690 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.1 |
| 3118 | HVAC Equipment | Air Source Heat Pump 21 SEER - Furnace baseline | Low Income | MF | LI | MO | 3,308 | 79% | 2,621 | 0.27 | 16 | $1,690 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.1 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3119 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 56% | 6,058 | 0.40 | 15 | $1,004 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 4.0 |
| 3120 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | Low Income | SF | LI | MO | 10,861 | 56% | 6,058 | 0.40 | 15 | $1,004 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 4.0 |
| 3121 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 56% | 6,058 | 0.40 | 15 | $1,004 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 4.0 |
| 3122 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | Low Income | MH | LI | MO | 10,861 | 56% | 6,058 | 0.40 | 15 | $1,004 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 4.0 |
| 3123 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 52% | 1,732 | 0.27 | 15 | $1,004 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.2 |
| 3124 | HVAC Equipment | Ductless Heat Pump 17 SEER 9.5 HSPF - Electric resistance baseline | Low Income | MF | LI | MO | 3,308 | 52% | 1,732 | 0.27 | 15 | $1,004 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.2 |
| 3125 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 57% | 6,226 | 0.60 | 15 | $1,004 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3126 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | Low Income | SF | LI | MO | 10,861 | 57% | 6,226 | 0.60 | 15 | $1,004 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 4.2 |
| 3127 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 57% | 6,226 | 0.60 | 15 | $1,004 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3128 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | Low Income | MH | LI | MO | 10,861 | 57% | 6,226 | 0.60 | 15 | $1,004 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3129 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 55% | 1,805 | 0.40 | 15 | $1,004 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3130 | HVAC Equipment | Ductless Heat Pump 19 SEER 9.5 HSPF - Electric resistance baseline | Low Income | MF | LI | MO | 3,308 | 55% | 1,805 | 0.40 | 15 | $1,004 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3131 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 60% | 6,523 | 0.75 | 15 | $1,070 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3132 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | Low Income | SF | LI | MO | 10,861 | 60% | 6,523 | 0.75 | 15 | $1,070 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 4.2 |
| 3133 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 60% | 6,523 | 0.75 | 15 | $1,070 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3134 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | Low Income | MH | LI | MO | 10,861 | 60% | 6,523 | 0.75 | 15 | $1,070 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 4.2 |
| 3135 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 58% | 1,908 | 0.50 | 15 | $1,070 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3136 | HVAC Equipment | Ductless Heat Pump 21 SEER 10.0 HSPF - Electric resistance baseline | Low Income | MF | LI | MO | 3,308 | 58% | 1,908 | 0.50 | 15 | $1,070 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 1.3 |
| 3137 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | SF | NLI | MO | 10,861 | 61% | 6,635 | 0.89 | 15 | $1,557 | 100% | 40% | HP-7 | 20% | 56% | 0.7 | 0.6 | 2.9 |
| 3138 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | Low Income | SF | LI | MO | 10,861 | 61% | 6,635 | 0.89 | 15 | $1,557 | 100% | 100% | HP-8 | 20% | 56% | 0.8 | 0.6 | 2.9 |
| 3139 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MH | NLI | MO | 10,861 | 61% | 6,635 | 0.89 | 15 | $1,557 | 100% | 40% | HP-9 | 20% | 56% | 0.7 | 0.6 | 2.9 |
| 3140 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | Low Income | MH | LI | MO | 10,861 | 61% | 6,635 | 0.89 | 15 | $1,557 | 100% | 100% | HP-10 | 20% | 56% | 0.7 | 0.6 | 2.9 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3141 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | HVAC and Water Heating - Equipment | MF | NLI | MO | 3,308 | 59% | 1,956 | 0.59 | 15 | $1,557 | 100% | 40% | HP-11 | 36% | 56% | 0.7 | 0.6 | 0.9 |
| 3142 | HVAC Equipment | Ductless Heat Pump 23 SEER 10.0 HSPF - Electric resistance baseline | Low Income | MF | LI | MO | 3,308 | 59% | 1,956 | 0.59 | 15 | $1,557 | 100% | 100% | HP-12 | 36% | 56% | 0.7 | 0.6 | 0.9 |
| 3143 | HVAC Equipment | AC Tune Up | No program | SF | NLI | Retrofit | 1,775 | 5% | 89 | 0.15 | 3 | $225 | 100% | 40% | AC TUNE-1 | 23% | 44% | 0.7 | 0.6 | 0.1 |
| 3144 | HVAC Equipment | AC Tune Up | Low Income | SF | LI | Retrofit | 1,775 | 5% | 89 | 0.15 | 3 | $225 | 100% | 100% | AC TUNE-2 | 23% | 44% | 0.8 | 0.6 | 0.1 |
| 3145 | HVAC Equipment | AC Tune Up | No program | MH | NLI | Retrofit | 1,775 | 5% | 89 | 0.15 | 3 | $225 | 100% | 40% | AC TUNE-3 | 23% | 44% | 0.7 | 0.6 | 0.1 |
| 3146 | HVAC Equipment | AC Tune Up | Low Income | MH | LI | Retrofit | 1,775 | 5% | 89 | 0.15 | 3 | $225 | 100% | 100% | AC TUNE-4 | 23% | 44% | 0.7 | 0.6 | 0.1 |
| 3147 | HVAC Equipment | AC Tune Up | No program | MF | NLI | Retrofit | 687 | 5% | 34 | 0.15 | 3 | $225 | 100% | 40% | AC TUNE-5 | 51% | 44% | 0.6 | 0.5 | 0.1 |
| 3148 | HVAC Equipment | AC Tune Up | Low Income | MF | LI | Retrofit | 687 | 5% | 34 | 0.15 | 3 | $225 | 100% | 100% | AC TUNE-6 | 51% | 44% | 0.6 | 0.6 | 0.1 |
| 3149 | HVAC Equipment | Central Air Conditioner 15 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 7% | 118 | 0.15 | 18 | $104 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 1.4 |
| 3150 | HVAC Equipment | Central Air Conditioner 15 SEER | Low Income | SF | LI | MO | 1,775 | 7% | 118 | 0.15 | 18 | $104 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 1.4 |
| 3151 | HVAC Equipment | Central Air Conditioner 15 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 7% | 118 | 0.15 | 18 | $104 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 1.4 |
| 3152 | HVAC Equipment | Central Air Conditioner 15 SEER | Low Income | MH | LI | MO | 1,775 | 7% | 118 | 0.15 | 18 | $104 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 1.4 |
| 3153 | HVAC Equipment | Central Air Conditioner 15 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 7% | 46 | 0.10 | 18 | $104 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.7 |
| 3154 | HVAC Equipment | Central Air Conditioner 15 SEER | Low Income | MF | LI | MO | 687 | 7% | 46 | 0.10 | 18 | $104 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.7 |
| 3155 | HVAC Equipment | Central Air Conditioner 16 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 1.2 |
| 3156 | HVAC Equipment | Central Air Conditioner 16 SEER | Low Income | SF | LI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 1.2 |
| 3157 | HVAC Equipment | Central Air Conditioner 16 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 1.2 |
| 3158 | HVAC Equipment | Central Air Conditioner 16 SEER | Low Income | MH | LI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 1.2 |
| 3159 | HVAC Equipment | Central Air Conditioner 16 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 40% | CAC-5 | 23% | 50% | 0.7 | 0.6 | 1.2 |
| 3160 | HVAC Equipment | Central Air Conditioner 16 SEER | Low Income | MF | LI | MO | 1,775 | 13% | 222 | 0.28 | 18 | $221 | 100% | 100% | CAC-6 | 23% | 50% | 0.7 | 0.6 | 1.2 |
| 3161 | HVAC Equipment | Central Air Conditioner 17 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 18% | 313 | 0.40 | 18 | $620 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3162 | HVAC Equipment | Central Air Conditioner 17 SEER | Low Income | SF | LI | MO | 1,775 | 18% | 313 | 0.40 | 18 | $620 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 0.6 |
| 3163 | HVAC Equipment | Central Air Conditioner 17 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 18% | 313 | 0.40 | 18 | $620 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3164 | HVAC Equipment | Central Air Conditioner 17 SEER | Low Income | MH | LI | MO | 1,775 | 18% | 313 | 0.40 | 18 | $620 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3165 | HVAC Equipment | Central Air Conditioner 17 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 18% | 121 | 0.27 | 18 | $620 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.3 |
| 3166 | HVAC Equipment | Central Air Conditioner 17 SEER | Low Income | MF | LI | MO | 687 | 18% | 121 | 0.27 | 18 | $620 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.3 |
| 3167 | HVAC Equipment | Central Air Conditioner 18 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 22% | 395 | 0.50 | 18 | $620 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 0.8 |
| 3168 | HVAC Equipment | Central Air Conditioner 18 SEER | Low Income | SF | LI | MO | 1,775 | 22% | 395 | 0.50 | 18 | $620 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 0.8 |
| 3169 | HVAC Equipment | Central Air Conditioner 18 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 22% | 395 | 0.50 | 18 | $620 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 0.8 |
| 3170 | HVAC Equipment | Central Air Conditioner 18 SEER | Low Income | MH | LI | MO | 1,775 | 22% | 395 | 0.50 | 18 | $620 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 0.8 |
| 3171 | HVAC Equipment | Central Air Conditioner 18 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 22% | 153 | 0.34 | 18 | $620 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.4 |
| 3172 | HVAC Equipment | Central Air Conditioner 18 SEER | Low Income | MF | LI | MO | 687 | 22% | 153 | 0.34 | 18 | $620 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.4 |
| 3173 | HVAC Equipment | Central Air Conditioner 19 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 27% | 476 | 0.61 | 18 | $620 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 0.9 |
| 3174 | HVAC Equipment | Central Air Conditioner 19 SEER | Low Income | SF | LI | MO | 1,775 | 27% | 476 | 0.61 | 18 | $620 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 0.9 |
| 3175 | HVAC Equipment | Central Air Conditioner 19 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 27% | 476 | 0.61 | 18 | $620 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 0.9 |
| 3176 | HVAC Equipment | Central Air Conditioner 19 SEER | Low Income | MH | LI | MO | 1,775 | 27% | 476 | 0.61 | 18 | $620 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 0.9 |
| 3177 | HVAC Equipment | Central Air Conditioner 19 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 27% | 184 | 0.40 | 18 | $620 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.5 |
| 3178 | HVAC Equipment | Central Air Conditioner 19 SEER | Low Income | MF | LI | MO | 687 | 27% | 184 | 0.40 | 18 | $620 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.5 |
| 3179 | HVAC Equipment | Central Air Conditioner 20 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 31% | 557 | 0.71 | 18 | $620 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 1.1 |
| 3180 | HVAC Equipment | Central Air Conditioner 20 SEER | Low Income | SF | LI | MO | 1,775 | 31% | 557 | 0.71 | 18 | $620 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 1.1 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3181 | HVAC Equipment | Central Air Conditioner 20 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 31% | 557 | 0.71 | 18 | $620 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 1.1 |
| 3182 | HVAC Equipment | Central Air Conditioner 20 SEER | Low Income | MH | LI | MO | 1,775 | 31% | 557 | 0.71 | 18 | $620 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 1.1 |
| 3183 | HVAC Equipment | Central Air Conditioner 20 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 31% | 215 | 0.47 | 18 | $620 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.6 |
| 3184 | HVAC Equipment | Central Air Conditioner 20 SEER | Low Income | MF | LI | MO | 687 | 31% | 215 | 0.47 | 18 | $620 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.6 |
| 3185 | HVAC Equipment | Central Air Conditioner 21 SEER | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 36% | 638 | 0.81 | 18 | $620 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 1.3 |
| 3186 | HVAC Equipment | Central Air Conditioner 21 SEER | Low Income | SF | LI | MO | 1,775 | 36% | 638 | 0.81 | 18 | $620 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 1.3 |
| 3187 | HVAC Equipment | Central Air Conditioner 21 SEER | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 36% | 638 | 0.81 | 18 | $620 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 1.3 |
| 3188 | HVAC Equipment | Central Air Conditioner 21 SEER | Low Income | MH | LI | MO | 1,775 | 36% | 638 | 0.81 | 18 | $620 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 1.3 |
| 3189 | HVAC Equipment | Central Air Conditioner 21 SEER | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 36% | 247 | 0.54 | 18 | $620 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.6 |
| 3190 | HVAC Equipment | Central Air Conditioner 21 SEER | Low Income | MF | LI | MO | 687 | 36% | 247 | 0.54 | 18 | $620 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.6 |
| 3191 | HVAC Equipment | Ductless AC | HVAC and Water Heating - Equipment | SF | NLI | MO | 1,775 | 9% | 167 | 0.20 | 18 | $365 | 100% | 40% | CAC-1 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3192 | HVAC Equipment | Ductless AC | Low Income | SF | LI | MO | 1,775 | 9% | 167 | 0.20 | 18 | $365 | 100% | 100% | CAC-2 | 23% | 50% | 0.8 | 0.6 | 0.6 |
| 3193 | HVAC Equipment | Ductless AC | HVAC and Water Heating - Equipment | MH | NLI | MO | 1,775 | 9% | 167 | 0.20 | 18 | $365 | 100% | 40% | CAC-3 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3194 | HVAC Equipment | Ductless AC | Low Income | MH | LI | MO | 1,775 | 9% | 167 | 0.20 | 18 | $365 | 100% | 100% | CAC-4 | 23% | 50% | 0.7 | 0.6 | 0.6 |
| 3195 | HVAC Equipment | Ductless AC | HVAC and Water Heating - Equipment | MF | NLI | MO | 687 | 9% | 65 | 0.20 | 18 | $365 | 100% | 40% | CAC-5 | 51% | 50% | 0.7 | 0.6 | 0.4 |
| 3196 | HVAC Equipment | Ductless AC | Low Income | MF | LI | MO | 687 | 9% | 65 | 0.20 | 18 | $365 | 100% | 100% | CAC-6 | 51% | 50% | 0.7 | 0.6 | 0.4 |
| 3197 | HVAC Equipment | Smart Thermostat - Heat pump baseline | HVAC and Water Heating - Equipment | SF | NLI | Retrofit | 5,508 | 8% | 441 | 0.13 | 11 | $125 | 100% | 40% | HERMOSTAT | 49% | 24% | 0.7 | 0.4 | 2.1 |
| 3198 | HVAC Equipment | Smart Thermostat - Heat pump baseline | Low Income | SF | LI | Retrofit | 5,508 | 8% | 441 | 0.13 | 11 | $125 | 100% | 100% | HERMOSTAT | 49% | 24% | 0.8 | 0.6 | 2.1 |
| 3199 | HVAC Equipment | Smart Thermostat - Heat pump baseline | HVAC and Water Heating - Equipment | MH | NLI | Retrofit | 5,508 | 8% | 441 | 0.13 | 11 | $125 | 100% | 40% | HERMOSTAT | 49% | 24% | 0.7 | 0.4 | 2.1 |
| 3200 | HVAC Equipment | Smart Thermostat - Heat pump baseline | Low Income | MH | LI | Retrofit | 5,508 | 8% | 441 | 0.13 | 11 | $125 | 100% | 100% | HERMOSTAT | 49% | 24% | 0.7 | 0.5 | 2.1 |
| 3201 | HVAC Equipment | Smart Thermostat - Heat pump baseline | HVAC and Water Heating - Equipment | MF | NLI | Retrofit | 2,018 | 8% | 161 | 0.04 | 11 | $125 | 100% | 40% | HERMOSTAT | 36% | 19% | 0.5 | 0.3 | 0.7 |
| 3202 | HVAC Equipment | Smart Thermostat - Heat pump baseline | Low Income | MF | LI | Retrofit | 2,018 | 8% | 161 | 0.04 | 11 | $125 | 100% | 100% | HERMOSTAT | 36% | 19% | 0.5 | 0.4 | 0.7 |
| 3203 | HVAC Equipment | Smart Thermostat - Furnace baseline | HVAC and Water Heating - Equipment | SF | NLI | Retrofit | 11,159 | 8% | 893 | 0.25 | 11 | $125 | 100% | 40% | HERMOSTAT | 20% | 24% | 0.7 | 0.4 | 4.1 |
| 3204 | HVAC Equipment | Smart Thermostat - Furnace baseline | Low Income | SF | LI | Retrofit | 11,159 | 8% | 893 | 0.25 | 11 | $125 | 100% | 100% | HERMOSTAT | 20% | 24% | 0.8 | 0.6 | 4.1 |
| 3205 | HVAC Equipment | Smart Thermostat - Furnace baseline | HVAC and Water Heating - Equipment | MH | NLI | Retrofit | 11,159 | 8% | 893 | 0.25 | 11 | $125 | 100% | 40% | HERMOSTAT | 20% | 24% | 0.7 | 0.4 | 4.1 |
| 3206 | HVAC Equipment | Smart Thermostat - Furnace baseline | Low Income | MH | LI | Retrofit | 11,159 | 8% | 893 | 0.25 | 11 | $125 | 100% | 100% | IERMOSTAT- | 20% | 24% | 0.7 | 0.5 | 4.1 |
| 3207 | HVAC Equipment | Smart Thermostat - Furnace baseline | HVAC and Water Heating - Equipment | MF | NLI | Retrofit | 3,396 | 8% | 272 | 0.06 | 11 | $125 | 100% | 40% | IERMOSTAT- | 47% | 19% | 0.5 | 0.3 | 1.2 |
| 3208 | HVAC Equipment | Smart Thermostat - Furnace baseline | Low Income | MF | LI | Retrofit | 3,396 | 8% | 272 | 0.06 | 11 | $125 | 100% | 100% | IERMOSTAT- | 47% | 19% | 0.5 | 0.4 | 1.2 |
| 3209 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | HVAC and Water Heating - Equipment | SF | NLI | Retrofit | 2,073 | 8% | 166 | 0.05 | 11 | $125 | 100% | 40% | IERMOSTAT- | 19% | 24% | 0.7 | 0.4 | 2.2 |
| 3210 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | Low Income | SF | LI | Retrofit | 2,073 | 8% | 166 | 0.05 | 11 | $125 | 100% | 100% | IERMOSTAT- | 19% | 24% | 0.8 | 0.6 | 2.2 |
| 3211 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | HVAC and Water Heating - Equipment | MH | NLI | Retrofit | 2,073 | 8% | 166 | 0.05 | 11 | $125 | 100% | 40% | IERMOSTAT- | 19% | 24% | 0.7 | 0.4 | 2.2 |
| 3212 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | Low Income | MH | LI | Retrofit | 2,073 | 8% | 166 | 0.05 | 11 | $125 | 100% | 100% | IERMOSTAT- | 19% | 24% | 0.7 | 0.5 | 2.2 |
| 3213 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | HVAC and Water Heating - Equipment | MF | NLI | Retrofit | 774 | 8% | 62 | 0.02 | 11 | $125 | 100% | 40% | IERMOSTAT- | 15% | 19% | 0.5 | 0.3 | 1.1 |
| 3214 | HVAC Equipment | Smart Thermostat - Gas/CAC baseline | Low Income | MF | LI | Retrofit | 774 | 8% | 62 | 0.02 | 11 | $125 | 100% | 100% | IERMOSTAT- | 15% | 19% | 0.5 | 0.4 | 1.1 |
| 3215 | HVAC Equipment | ECM HVAC Motor | No program | SF | NLI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 40% | ECM-1 | 75% | 50% | 0.7 | 0.6 | 0.7 |
| 3216 | HVAC Equipment | ECM HVAC Motor | No program | SF | LI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 100% | ECM-2 | 75% | 50% | 0.8 | 0.6 | 0.7 |
| 3217 | HVAC Equipment | ECM HVAC Motor | No program | MH | NLI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 40% | ECM-3 | 75% | 50% | 0.7 | 0.6 | 0.7 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3218 | HVAC Equipment | ECM HVAC Motor | No program | MH | LI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 100% | ECM-4 | 75% | 50% | 0.7 | 0.6 | 0.7 |
| 3219 | HVAC Equipment | ECM HVAC Motor | No program | MF | NLI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 40% | ECM-5 | 60% | 50% | 0.7 | 0.6 | 0.7 |
| 3220 | HVAC Equipment | ECM HVAC Motor | No program | MF | LI | Retrofit | 1,455 | 40% | 582 | 0.27 | 6 | $322 | 100% | 100% | ECM-6 | 60% | 50% | 0.7 | 0.6 | 0.7 |
| 3221 | HVAC Equipment | ENERGY STAR Room Air Conditioner | HVAC and Water Heating - Equipment | SF | NLI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 40% | RAC-1 | 70% | 49% | 0.7 | 0.6 | 2.2 |
| 3222 | HVAC Equipment | ENERGY STAR Room Air Conditioner | Low Income | SF | LI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 100% | RAC-2 | 70% | 49% | 0.8 | 0.6 | 2.2 |
| 3223 | HVAC Equipment | ENERGY STAR Room Air Conditioner | HVAC and Water Heating - Equipment | MH | NLI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 40% | RAC-3 | 70% | 49% | 0.7 | 0.6 | 2.2 |
| 3224 | HVAC Equipment | ENERGY STAR Room Air Conditioner | Low Income | MH | LI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 100% | RAC-4 | 72% | 49% | 0.7 | 0.6 | 2.2 |
| 3225 | HVAC Equipment | ENERGY STAR Room Air Conditioner | HVAC and Water Heating - Equipment | MF | NLI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 40% | RAC-5 | 72% | 49% | 0.6 | 0.6 | 2.2 |
| 3226 | HVAC Equipment | ENERGY STAR Room Air Conditioner | Low Income | MF | LI | MO | 794 | 9% | 73 | 0.07 | 9 | $20 | 100% | 100% | RAC-6 | 72% | 49% | 0.6 | 0.6 | 2.2 |
| 3227 | HVAC Equipment | Room Air Conditioner Recycling | No program | SF | NLI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 40% | RR-1 | 16% | 0% | 0.7 | 0.3 | 0.9 |
| 3228 | HVAC Equipment | Room Air Conditioner Recycling | Low Income | SF | LI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 100% | RR-2 | 16% | 0% | 0.8 | 0.6 | 0.9 |
| 3229 | HVAC Equipment | Room Air Conditioner Recycling | No program | MH | NLI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 40% | RR-3 | 16% | 0% | 0.7 | 0.3 | 0.9 |
| 3230 | HVAC Equipment | Room Air Conditioner Recycling | Low Income | MH | LI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 100% | RR-4 | 16% | 0% | 0.7 | 0.5 | 0.9 |
| 3231 | HVAC Equipment | Room Air Conditioner Recycling | No program | MF | NLI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 40% | RR-5 | 8% | 0% | 0.5 | 0.2 | 0.9 |
| 3232 | HVAC Equipment | Room Air Conditioner Recycling | Low Income | MF | LI | Recycle | 196 | 100% | 196 | 0.19 | 4 | $65 | 100% | 100% | RR-6 | 8% | 0% | 0.5 | 0.3 | 0.9 |
| 3233 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | SF | NLI | Retrofit | 2,073 | 5% | 104 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-1 | 19% | 3% | 0.7 | 0.3 | 0.1 |
| 3234 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | SF | LI | Retrofit | 2,073 | 5% | 104 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-2 | 19% | 3% | 0.8 | 0.6 | 0.1 |
| 3235 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | MH | NLI | Retrofit | 2,073 | 5% | 104 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-3 | 19% | 3% | 0.7 | 0.3 | 0.1 |
| 3236 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | MH | LI | Retrofit | 2,073 | 5% | 104 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-4 | 19% | 3% | 0.7 | 0.5 | 0.1 |
| 3237 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | MF | NLI | Retrofit | 774 | 5% | 39 | 0.08 | 15 | $1,040 | 100% | 40% | SVS-5 | 15% | 3% | 0.5 | 0.2 | 0.1 |
| 3238 | HVAC Equipment | Smart Vents/Sensors - Gas/CAC baseline | No program | MF | LI | Retrofit | 774 | 5% | 39 | 0.08 | 15 | $1,040 | 100% | 100% | SVS-6 | 15% | 3% | 0.5 | 0.3 | 0.1 |
| 3239 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | SF | NLI | Retrofit | 5,508 | 5% | 275 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-7 | 49% | 3% | 0.7 | 0.3 | 0.1 |
| 3240 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | SF | LI | Retrofit | 5,508 | 5% | 275 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-8 | 49% | 3% | 0.8 | 0.6 | 0.1 |
| 3241 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | MH | NLI | Retrofit | 5,508 | 5% | 275 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-9 | 49% | 3% | 0.7 | 0.3 | 0.1 |
| 3242 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | MH | LI | Retrofit | 5,508 | 5% | 275 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-10 | 49% | 3% | 0.7 | 0.5 | 0.1 |
| 3243 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | MF | NLI | Retrofit | 2,018 | 5% | 101 | 0.08 | 15 | $1,040 | 100% | 40% | SVS-11 | 36% | 3% | 0.5 | 0.2 | 0.1 |
| 3244 | HVAC Equipment | Smart Vents/Sensors - Heat pump baseline | No program | MF | LI | Retrofit | 2,018 | 5% | 101 | 0.08 | 15 | $1,040 | 100% | 100% | SVS-12 | 36% | 3% | 0.5 | 0.3 | 0.1 |
| 3245 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | SF | NLI | Retrofit | 10,861 | 5% | 543 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-13 | 20% | 3% | 0.7 | 0.3 | 0.2 |
| 3246 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | SF | LI | Retrofit | 10,861 | 5% | 543 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-14 | 20% | 3% | 0.8 | 0.6 | 0.2 |
| 3247 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | MH | NLI | Retrofit | 10,861 | 5% | 543 | 0.11 | 15 | $1,625 | 100% | 40% | SVS-15 | 20% | 3% | 0.7 | 0.3 | 0.2 |
| 3248 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | MH | LI | Retrofit | 10,861 | 5% | 543 | 0.11 | 15 | $1,625 | 100% | 100% | SVS-16 | 20% | 3% | 0.7 | 0.5 | 0.2 |
| 3249 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | MF | NLI | Retrofit | 3,396 | 5% | 170 | 0.08 | 15 | $1,040 | 100% | 40% | SVS-17 | 47% | 3% | 0.5 | 0.2 | 0.1 |
| 3250 | HVAC Equipment | Smart Vents/Sensors - Furnace baseline | No program | MF | LI | Retrofit | 3,396 | 5% | 170 | 0.08 | 15 | $1,040 | 100% | 100% | SVS-18 | 47% | 3% | 0.5 | 0.3 | 0.1 |
| 3251 | HVAC Equipment | Energy Recovery Ventilator | No program | SF | NLI | Retrofit | 5,569 | 40% | 2,228 | 0.30 | 15 | $3,000 | 100% | 40% | ERV-1 | 50% | 0% | 0.7 | 0.3 | 0.6 |
| 3252 | HVAC Equipment | Energy Recovery Ventilator | No program | SF | LI | Retrofit | 5,569 | 40% | 2,228 | 0.30 | 15 | $3,000 | 100% | 100% | ERV-2 | 50% | 0% | 0.8 | 0.6 | 0.6 |
| 3253 | HVAC Equipment | Energy Recovery Ventilator | No program | MH | NLI | Retrofit | 5,569 | 40% | 2,228 | 0.30 | 15 | $3,000 | 100% | 40% | ERV-3 | 50% | 0% | 0.7 | 0.3 | 0.6 |
| 3254 | HVAC Equipment | Energy Recovery Ventilator | No program | MH | LI | Retrofit | 5,569 | 40% | 2,228 | 0.30 | 15 | $3,000 | 100% | 100% | ERV-4 | 50% | 0% | 0.7 | 0.5 | 0.6 |
| 3255 | HVAC Equipment | Energy Recovery Ventilator | No program | MF | NLI | Retrofit | 2,461 | 40% | 984 | 0.30 | 15 | $3,000 | 100% | 40% | ERV-5 | 50% | 0% | 0.5 | 0.2 | 0.3 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3256 | HVAC Equipment | Energy Recovery Ventilator | No program | MF | LI | Retrofit | 2,461 | 40% | 984 | 0.30 | 15 | $3,000 | 100% | 100% | ERV-6 | 50% | 0% | 0.5 | 0.3 | 0.3 |
| 3257 | HVAC Equipment | Whole House Attic Fan | No program | SF | NLI | Retrofit | 2,073 | 18% | 373 | 0.41 | 15 | $711 | 100% | 40% | WHAF-1 | 23% | 7% | 0.7 | 0.3 | 0.5 |
| 3258 | HVAC Equipment | Whole House Attic Fan | No program | SF | LI | Retrofit | 2,073 | 18% | 373 | 0.41 | 15 | $711 | 100% | 100% | WHAF-2 | 23% | 7% | 0.8 | 0.6 | 0.5 |
| 3259 | HVAC Equipment | Whole House Attic Fan | No program | MH | NLI | Retrofit | 2,073 | 18% | 373 | 0.41 | 15 | $711 | 100% | 40% | WHAF-3 | 23% | 7% | 0.7 | 0.3 | 0.5 |
| 3260 | HVAC Equipment | Whole House Attic Fan | No program | MH | LI | Retrofit | 2,073 | 18% | 373 | 0.41 | 15 | $711 | 100% | 100% | WHAF-4 | 23% | 7% | 0.7 | 0.5 | 0.5 |
| 3261 | HVAC Equipment | Whole House Attic Fan | No program | MF | NLI | Retrofit | 687 | 18% | 124 | 0.27 | 15 | $711 | 100% | 40% | WHAF-5 | 51% | 7% | 0.5 | 0.2 | 0.2 |
| 3262 | HVAC Equipment | Whole House Attic Fan | No program | MF | LI | Retrofit | 687 | 18% | 124 | 0.27 | 15 | $711 | 100% | 100% | WHAF-6 | 51% | 7% | 0.5 | 0.3 | 0.2 |
| 3263 | HVAC Equipment | Attic Fan | No program | SF | NLI | Retrofit | 2,073 | 8% | 166 | 0.18 | 15 | $125 | 100% | 40% | WHAF-1 | 23% | 8% | 0.7 | 0.3 | 1.3 |
| 3264 | HVAC Equipment | Attic Fan | No program | SF | LI | Retrofit | 2,073 | 8% | 166 | 0.18 | 15 | $125 | 100% | 100% | WHAF-2 | 23% | 8% | 0.8 | 0.6 | 1.3 |
| 3265 | HVAC Equipment | Attic Fan | No program | MH | NLI | Retrofit | 2,073 | 8% | 166 | 0.18 | 15 | $125 | 100% | 40% | WHAF-3 | 23% | 8% | 0.7 | 0.3 | 1.3 |
| 3266 | HVAC Equipment | Attic Fan | No program | MH | LI | Retrofit | 2,073 | 8% | 166 | 0.18 | 15 | $125 | 100% | 100% | WHAF-4 | 23% | 8% | 0.7 | 0.5 | 1.3 |
| 3267 | HVAC Equipment | Attic Fan | No program | MF | NLI | Retrofit | 687 | 8% | 55 | 0.12 | 15 | $125 | 100% | 40% | WHAF-5 | 51% | 8% | 0.5 | 0.2 | 0.6 |
| 3268 | HVAC Equipment | Attic Fan | No program | MF | LI | Retrofit | 687 | 8% | 55 | 0.12 | 15 | $125 | 100% | 100% | WHAF-6 | 51% | 8% | 0.5 | 0.3 | 0.6 |
| 3269 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | SF | NLI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 40% | VENT FAN-1 | 75% | 51% | 0.7 | 0.6 | 0.7 |
| 3270 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | SF | LI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 100% | VENT FAN-2 | 75% | 51% | 0.8 | 0.6 | 0.7 |
| 3271 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | MH | NLI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 40% | VENT FAN-3 | 75% | 51% | 0.7 | 0.6 | 0.7 |
| 3272 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | MH | LI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 100% | VENT FAN-4 | 75% | 51% | 0.7 | 0.6 | 0.7 |
| 3273 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | MF | NLI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 40% | VENT FAN-5 | 75% | 51% | 0.7 | 0.6 | 0.7 |
| 3274 | HVAC Equipment | ENERGY STAR Bath Vent Fan | No program | MF | LI | Retrofit | 100 | 10% | 10 | 0.00 | 19 | $11 | 100% | 100% | VENT FAN-6 | 75% | 51% | 0.7 | 0.6 | 0.7 |
| 4001 | Lighting | 9W LED | No program | SF | NLI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 40% | STAN-1 | 3003% | 59% | 0.7 | 0.7 | 2.1 |
| 4002 | Lighting | 9W LED | No program | SF | LI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 100% | STAN-2 | 3003% | 59% | 0.8 | 0.7 | 2.1 |
| 4003 | Lighting | 9W LED | No program | MH | NLI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 40% | STAN-3 | 3003% | 59% | 0.7 | 0.7 | 2.1 |
| 4004 | Lighting | 9W LED | No program | MH | LI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 100% | STAN-4 | 3003% | 59% | 0.8 | 0.7 | 2.1 |
| 4005 | Lighting | 9W LED | No program | MF | NLI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 40% | STAN-5 | 1915% | 59% | 0.7 | 0.7 | 2.1 |
| 4006 | Lighting | 9W LED | No program | MF | LI | MO | 32 | 9% | 3 | 0.00 | 19 | $1 | 100% | 100% | STAN-6 | 1915% | 59% | 0.7 | 0.7 | 2.1 |
| 4007 | Lighting | 13W LED | No program | SF | NLI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 40% | STAN-1 | 3003% | 59% | 0.7 | 0.7 | 0.9 |
| 4008 | Lighting | 13W LED | No program | SF | LI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 100% | STAN-2 | 3003% | 59% | 0.8 | 0.7 | 0.9 |
| 4009 | Lighting | 13W LED | No program | MH | NLI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 40% | STAN-3 | 3003% | 59% | 0.7 | 0.7 | 0.9 |
| 4010 | Lighting | 13W LED | No program | MH | LI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 100% | STAN-4 | 3003% | 59% | 0.8 | 0.7 | 0.9 |
| 4011 | Lighting | 13W LED | No program | MF | NLI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 40% | STAN-5 | 1915% | 59% | 0.7 | 0.7 | 0.9 |
| 4012 | Lighting | 13W LED | No program | MF | LI | MO | 38 | 13% | 5 | 0.00 | 19 | $5 | 100% | 100% | STAN-6 | 1915% | 59% | 0.7 | 0.7 | 0.9 |
| 4013 | Lighting | LED 5W Globe | No program | SF | NLI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 40% | REFLECTOR-1 | 738% | 59% | 0.7 | 0.7 | 0.3 |
| 4014 | Lighting | LED 5W Globe | No program | SF | LI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 100% | REFLECTOR-2 | 738% | 59% | 0.8 | 0.7 | 0.3 |
| 4015 | Lighting | LED 5W Globe | No program | MH | NLI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 40% | REFLECTOR-3 | 738% | 59% | 0.7 | 0.7 | 0.3 |
| 4016 | Lighting | LED 5W Globe | No program | MH | LI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 100% | REFLECTOR-4 | 738% | 59% | 0.8 | 0.7 | 0.3 |
| 4017 | Lighting | LED 5W Globe | No program | MF | NLI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 40% | REFLECTOR-5 | 471% | 59% | 0.7 | 0.7 | 0.3 |
| 4018 | Lighting | LED 5W Globe | No program | MF | LI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 100% | REFLECTOR-6 | 471% | 59% | 0.7 | 0.7 | 0.3 |
| 4019 | Lighting | LED R30 Dimmable | No program | SF | NLI | MO | 5 | 20% | 1 | 0.00 | 19 | $3 | 100% | 40% | SPECIALTY-1 | 446% | 59% | 0.7 | 0.7 | 0.3 |
| 4020 | Lighting | LED R30 Dimmable | No program | SF | LI | MO | 43 | 26% | 11 | 0.00 | 19 | $4 | 100% | 100% | SPECIALTY-2 | 446% | 59% | 0.8 | 0.7 | 2.5 |
| 4021 | Lighting | LED R30 Dimmable | No program | MH | NLI | MO | 43 | 26% | 11 | 0.00 | 19 | $4 | 100% | 40% | SPECIALTY-3 | 446% | 59% | 0.7 | 0.7 | 2.5 |
| 4022 | Lighting | LED R30 Dimmable | No program | MH | LI | MO | 43 | 26% | 11 | 0.00 | 19 | $4 | 100% | 100% | SPECIALTY-4 | 446% | 59% | 0.8 | 0.7 | 2.5 |
| 4023 | Lighting | LED R30 Dimmable | No program | MF | NLI | MO | 43 | 26% | 11 | 0.00 | 19 | $4 | 100% | 40% | SPECIALTY-5 | 284% | 59% | 0.7 | 0.7 | 2.5 |
| 4024 | Lighting | LED R30 Dimmable | No program | MF | LI | MO | 43 | 26% | 11 | 0.00 | 19 | $4 | 100% | 100% | SPECIALTY-6 | 284% | 59% | 0.7 | 0.7 | 2.5 |
| 4025 | Lighting | LED Nightlights | No program | SF | NLI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 40% | NIGHT-1 | 40% | 59% | 0.7 | 0.7 | 2.3 |
| 4026 | Lighting | LED Nightlights | No program | SF | LI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 100% | NIGHT-2 | 40% | 59% | 0.8 | 0.7 | 2.3 |
| 4027 | Lighting | LED Nightlights | No program | MH | NLI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 40% | NIGHT-3 | 40% | 59% | 0.7 | 0.7 | 2.3 |
| 4028 | Lighting | LED Nightlights | No program | MH | LI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 100% | NIGHT-4 | 40% | 59% | 0.8 | 0.7 | 2.3 |
| 4029 | Lighting | LED Nightlights | No program | MF | NLI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 40% | NIGHT-5 | 40% | 59% | 0.7 | 0.7 | 2.3 |
| 4030 | Lighting | LED Nightlights | No program | MF | LI | MO | 15 | 93% | 14 | 0.00 | 12 | $3 | 100% | 100% | NIGHT-6 | 40% | 59% | 0.7 | 0.7 | 2.3 |
| 4031 | Lighting | Exterior LED Lamp | No program | SF | NLI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 40% | ELL-1 | 503% | 59% | 0.7 | 0.7 | 39.4 |
| 4032 | Lighting | Exterior LED Lamp | No program | SF | LI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 100% | ELL-2 | 503% | 59% | 0.8 | 0.7 | 39.4 |
| 4033 | Lighting | Exterior LED Lamp | No program | MH | NLI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 40% | ELL-3 | 503% | 59% | 0.7 | 0.7 | 39.4 |
| 4034 | Lighting | Exterior LED Lamp | No program | MH | LI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 100% | ELL-4 | 289% | 59% | 0.8 | 0.7 | 39.4 |
| 4035 | Lighting | Exterior LED Lamp | No program | MF | NLI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 40% | ELL-5 | 289% | 59% | 0.7 | 0.7 | 39.4 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4036 | Lighting | Exterior LED Lamp | No program | MF | LI | MO | 127 | 72% | 92 | 0.00 | 19 | $2 | 100% | 100% | ELL-6 | 289% | 59% | 0.7 | 0.7 | 39.4 |
| 4037 | Lighting | Linear LED | No program | SF | NLI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 40% | LINEAR-1 | 509% | 59% | 0.7 | 0.7 | 1.9 |
| 4038 | Lighting | Linear LED | No program | SF | LI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 100% | LINEAR-2 | 509% | 59% | 0.8 | 0.7 | 1.9 |
| 4039 | Lighting | Linear LED | No program | MH | NLI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 40% | LINEAR-3 | 509% | 59% | 0.7 | 0.7 | 1.9 |
| 4040 | Lighting | Linear LED | No program | MH | LI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 100% | LINEAR-4 | 509% | 59% | 0.8 | 0.7 | 1.9 |
| 4041 | Lighting | Linear LED | No program | MF | NLI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 40% | LINEAR-5 | 325% | 59% | 0.7 | 0.7 | 1.9 |
| 4042 | Lighting | Linear LED | No program | MF | LI | MO | 23 | 44% | 10 | 0.01 | 19 | $7 | 100% | 100% | LINEAR-6 | 325% | 59% | 0.7 | 0.7 | 1.9 |
| 4043 | Lighting | Smart LED | No program | SF | NLI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 40% | STAN-1 | 3003% | 59% | 0.7 | 0.7 | 0.7 |
| 4044 | Lighting | Smart LED | No program | SF | LI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 100% | STAN-2 | 3003% | 59% | 0.8 | 0.7 | 0.7 |
| 4045 | Lighting | Smart LED | No program | MH | NLI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 40% | STAN-3 | 3003% | 59% | 0.7 | 0.7 | 0.7 |
| 4046 | Lighting | Smart LED | No program | MH | LI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 100% | STAN-4 | 3003% | 59% | 0.8 | 0.7 | 0.7 |
| 4047 | Lighting | Smart LED | No program | MF | NLI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 40% | STAN-5 | 1915% | 59% | 0.7 | 0.7 | 0.7 |
| 4048 | Lighting | Smart LED | No program | MF | LI | MO | 19 | 10% | 2 | 0.00 | 19 | $2 | 100% | 100% | STAN-6 | 1915% | 59% | 0.7 | 0.7 | 0.7 |
| 4049 | Lighting | LED Fixture | No program | SF | NLI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 40% | STAN-1 | 3003% | 59% | 0.7 | 0.7 | 2.4 |
| 4050 | Lighting | LED Fixture | No program | SF | LI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 100% | STAN-2 | 3003% | 59% | 0.8 | 0.7 | 2.4 |
| 4051 | Lighting | LED Fixture | No program | MH | NLI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 40% | STAN-3 | 3003% | 59% | 0.7 | 0.7 | 2.4 |
| 4052 | Lighting | LED Fixture | No program | MH | LI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 100% | STAN-4 | 3003% | 59% | 0.8 | 0.7 | 2.4 |
| 4053 | Lighting | LED Fixture | No program | MF | NLI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 40% | STAN-5 | 1915% | 59% | 0.7 | 0.7 | 2.4 |
| 4054 | Lighting | LED Fixture | No program | MF | LI | MO | 82 | 59% | 49 | 0.06 | 19 | $26 | 100% | 100% | STAN-6 | 1915% | 59% | 0.7 | 0.7 | 2.4 |
| 4055 | Lighting | Occupancy Sensor | No program | SF | NLI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 40% | OCC-1 | 1047% | 31% | 0.7 | 0.4 | 0.9 |
| 4056 | Lighting | Occupancy Sensor | No program | SF | LI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 100% | OCC-2 | 1047% | 31% | 0.8 | 0.6 | 0.9 |
| 4057 | Lighting | Occupancy Sensor | No program | MH | NLI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 40% | OCC-3 | 1047% | 31% | 0.7 | 0.4 | 0.9 |
| 4058 | Lighting | Occupancy Sensor | No program | MH | LI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 100% | OCC-4 | 1047% | 31% | 0.8 | 0.6 | 0.9 |
| 4059 | Lighting | Occupancy Sensor | No program | MF | NLI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 40% | OCC-5 | 1047% | 31% | 0.6 | 0.4 | 0.9 |
| 4060 | Lighting | Occupancy Sensor | No program | MF | LI | Retrofit | 124 | 30% | 37 | 0.05 | 10 | $30 | 100% | 100% | OCC-6 | 1047% | 31% | 0.7 | 0.5 | 0.9 |
| 4061 | Lighting | Smart Lighting Switch | No program | SF | NLI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 40% | OCC-1 | 1047% | 31% | 0.7 | 0.4 | 0.5 |
| 4062 | Lighting | Smart Lighting Switch | No program | SF | LI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 100% | OCC-2 | 1047% | 31% | 0.8 | 0.6 | 0.5 |
| 4063 | Lighting | Smart Lighting Switch | No program | MH | NLI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 40% | OCC-3 | 1047% | 31% | 0.7 | 0.4 | 0.5 |
| 4064 | Lighting | Smart Lighting Switch | No program | MH | LI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 100% | OCC-4 | 1047% | 31% | 0.8 | 0.6 | 0.5 |
| 4065 | Lighting | Smart Lighting Switch | No program | MF | NLI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 40% | OCC-5 | 1047% | 31% | 0.6 | 0.4 | 0.5 |
| 4066 | Lighting | Smart Lighting Switch | No program | MF | LI | Retrofit | 124 | 17% | 21 | 0.05 | 10 | $43 | 100% | 100% | OCC-6 | 1047% | 31% | 0.7 | 0.5 | 0.5 |
| 4067 | Lighting | Exterior Lighting Controls | No program | SF | NLI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 40% | ELC-1 | 252% | 31% | 0.7 | 0.4 | 1.1 |
| 4068 | Lighting | Exterior Lighting Controls | No program | SF | LI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 100% | ELC-2 | 252% | 31% | 0.8 | 0.6 | 1.1 |
| 4069 | Lighting | Exterior Lighting Controls | No program | MH | NLI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 40% | ELC-3 | 252% | 31% | 0.7 | 0.4 | 1.1 |
| 4070 | Lighting | Exterior Lighting Controls | No program | MH | LI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 100% | ELC-4 | 252% | 31% | 0.8 | 0.6 | 1.1 |
| 4071 | Lighting | Exterior Lighting Controls | No program | MF | NLI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 40% | ELC-5 | 252% | 31% | 0.6 | 0.4 | 1.1 |
| 4072 | Lighting | Exterior Lighting Controls | No program | MF | LI | Retrofit | 146 | 44% | 65 | 0.03 | 10 | $30 | 100% | 100% | ELC-6 | 252% | 31% | 0.7 | 0.5 | 1.1 |
| 5001 | Pool/Pump | Heat Pump Pool Heater | No program | SF | NLI | MO | 2,364 | 52% | 1,234 | 0.00 | 8 | $1,250 | 100% | 40% | HPPH-1 | 3% | 12% | 0.7 | 0.3 | 0.4 |
| 5002 | Pool/Pump | Heat Pump Pool Heater | No program | SF | LI | MO | 2,364 | 52% | 1,234 | 0.00 | 8 | $1,250 | 100% | 100% | HPPH-2 | 3% | 12% | 0.8 | 0.6 | 0.4 |
| 5003 | Pool/Pump | Heat Pump Pool Heater | No program | MH | NLI | MO | 2,364 | 52% | 1,234 | 0.00 | 8 | $1,250 | 100% | 40% | HPPH-3 | 3% | 12% | 0.7 | 0.3 | 0.4 |
| 5004 | Pool/Pump | Heat Pump Pool Heater | No program | MH | LI | MO | 2,364 | 52% | 1,234 | 0.00 | 8 | $1,250 | 100% | 100% | HPPH-4 | 3% | 12% | 0.8 | 0.6 | 0.4 |
| 5005 | Pool/Pump | Variable Speed Pool Pump | No program | SF | NLI | MO | 1,167 | 26% | 308 | 0.22 | 7 | $314 | 100% | 40% | POOL-1 | 10% | 25% | 0.7 | 0.4 | 0.4 |
| 5006 | Pool/Pump | Variable Speed Pool Pump | No program | SF | LI | MO | 1,167 | 26% | 308 | 0.22 | 7 | $314 | 100% | 100% | POOL-2 | 10% | 25% | 0.8 | 0.6 | 0.4 |
| 5007 | Pool/Pump | Variable Speed Pool Pump | No program | MH | NLI | MO | 1,167 | 26% | 308 | 0.22 | 7 | $314 | 100% | 40% | POOL-3 | 10% | 25% | 0.7 | 0.4 | 0.4 |
| 5008 | Pool/Pump | Variable Speed Pool Pump | No program | MH | LI | MO | 1,167 | 26% | 308 | 0.22 | 7 | $314 | 100% | 100% | POOL-4 | 10% | 25% | 0.8 | 0.6 | 0.4 |
| 5009 | Pool/Pump | Well Pump | No program | SF | NLI | MO | 411 | 33% | 136 | 0.02 | 20 | $110 | 100% | 40% | WELL-1 | 4% | 25% | 0.7 | 0.4 | 1.0 |
| 5010 | Pool/Pump | Well Pump | No program | SF | LI | MO | 411 | 33% | 136 | 0.02 | 20 | $110 | 100% | 100% | WELL-2 | 4% | 25% | 0.8 | 0.6 | 1.0 |
| 5011 | Pool/Pump | Well Pump | No program | MH | NLI | MO | 411 | 33% | 136 | 0.02 | 20 | $110 | 100% | 40% | WELL-3 | 4% | 25% | 0.7 | 0.4 | 1.0 |
| 5012 | Pool/Pump | Well Pump | No program | MH | LI | MO | 411 | 33% | 136 | 0.02 | 20 | $110 | 100% | 100% | WELL-4 | 4% | 25% | 0.8 | 0.6 | 1.0 |
| 6001 | New Construction | ENERGY STAR New Home | No program | SF | N/A | NC | 14,827 | 25% | 3,707 | 0.42 | 20 | $1,216 | 100% | 40% | NC-1 | 100% | 0% | 0.7 | 0.2 | 2.6 |
| 6002 | New Construction | ENERGY STAR New Home | No program | MH | N/A | NC | 14,827 | 25% | 3,707 | 0.42 | 20 | $1,216 | 100% | 40% | NC-2 | 100% | 0% | 0.7 | 0.2 | 2.6 |
| 6003 | New Construction | ENERGY STAR New Home | No program | MF | N/A | NC | 14,827 | 25% | 3,707 | 0.42 | 20 | $1,216 | 100% | 40% | NC-3 | 100% | 0% | 0.5 | 0.2 | 2.6 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7001 | Plug Load | Smart Power Strips - Tier 1 | No program | SF | NLI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 40% | SPS-1 | 100% | 16% | 0.7 | 0.3 | 2.0 |
| 7002 | Plug Load | Smart Power Strips - Tier 1 | No program | SF | LI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 100% | SPS-2 | 100% | 16% | 0.8 | 0.6 | 2.0 |
| 7003 | Plug Load | Smart Power Strips - Tier 1 | No program | MH | NLI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 40% | SPS-3 | 100% | 16% | 0.7 | 0.3 | 2.0 |
| 7004 | Plug Load | Smart Power Strips - Tier 1 | No program | MH | LI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 100% | SPS-4 | 100% | 16% | 0.8 | 0.6 | 2.0 |
| 7005 | Plug Load | Smart Power Strips - Tier 1 | No program | MF | NLI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 40% | SPS-5 | 100% | 16% | 0.6 | 0.3 | 2.0 |
| 7006 | Plug Load | Smart Power Strips - Tier 1 | No program | MF | LI | Retrofit | 466 | 5% | 57 | 0.01 | 7 | $10 | 100% | 100% | SPS-6 | 100% | 16% | 0.7 | 0.5 | 2.0 |
| 7007 | Plug Load | Smart Power Strips - Tier 2 | No program | SF | NLI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 40% | SPS-1 | 100% | 16% | 0.7 | 0.3 | 0.8 |
| 7008 | Plug Load | Smart Power Strips - Tier 2 | No program | SF | LI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 100% | SPS-2 | 100% | 16% | 0.8 | 0.6 | 0.8 |
| 7009 | Plug Load | Smart Power Strips - Tier 2 | No program | MH | NLI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 40% | SPS-3 | 100% | 16% | 0.7 | 0.3 | 0.8 |
| 7010 | Plug Load | Smart Power Strips - Tier 2 | No program | MH | LI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 100% | SPS-4 | 100% | 16% | 0.8 | 0.6 | 0.8 |
| 7011 | Plug Load | Smart Power Strips - Tier 2 | No program | MF | NLI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 40% | SPS-5 | 100% | 16% | 0.6 | 0.3 | 0.8 |
| 7012 | Plug Load | Smart Power Strips - Tier 2 | No program | MF | LI | Retrofit | 466 | 29% | 136 | 0.02 | 7 | $60 | 100% | 100% | SPS-6 | 100% | 16% | 0.7 | 0.5 | 0.8 |
| 7013 | Plug Load | ENERGY STAR TV | No program | SF | NLI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 40% | TV-1 | 200% | 46% | 0.7 | 0.6 | 1.0 |
| 7014 | Plug Load | ENERGY STAR TV | No program | SF | LI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 100% | TV-2 | 200% | 46% | 0.8 | 0.6 | 1.0 |
| 7015 | Plug Load | ENERGY STAR TV | No program | MH | NLI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 40% | TV-3 | 200% | 46% | 0.7 | 0.6 | 1.0 |
| 7016 | Plug Load | ENERGY STAR TV | No program | MH | LI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 100% | TV-4 | 200% | 46% | 0.8 | 0.6 | 1.0 |
| 7017 | Plug Load | ENERGY STAR TV | No program | MF | NLI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 40% | TV-5 | 200% | 46% | 0.6 | 0.6 | 1.0 |
| 7018 | Plug Load | ENERGY STAR TV | No program | MF | LI | MO | 83 | 20% | 17 | 0.00 | 6 | $0 | 100% | 100% | TV-6 | 200% | 46% | 0.7 | 0.6 | 1.0 |
| 8001 | Shell | Duct Sealing - Average Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 5% | 263 | 0.13 | 20 | $450 | 100% | 40% | DUCT-1 | 49% | 76% | 0.8 | 0.8 | 0.6 |
| 8002 | Shell | Duct Sealing - Average Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 5% | 263 | 0.13 | 20 | $450 | 100% | 100% | DUCT-2 | 49% | 76% | 0.8 | 0.8 | 0.6 |
| 8003 | Shell | Duct Sealing - Average Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 5% | 263 | 0.13 | 20 | $450 | 100% | 40% | DUCT-3 | 49% | 76% | 0.8 | 0.8 | 0.6 |
| 8004 | Shell | Duct Sealing - Average Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 5% | 263 | 0.13 | 20 | $450 | 100% | 100% | DUCT-4 | 49% | 76% | 0.8 | 0.8 | 0.6 |
| 8005 | Shell | Duct Sealing - Inadequate Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 7% | 367 | 0.11 | 20 | $450 | 100% | 40% | DUCT-5 | 49% | 90% | 0.9 | 0.9 | 0.8 |
| 8006 | Shell | Duct Sealing - Inadequate Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 7% | 367 | 0.11 | 20 | $450 | 100% | 100% | DUCT-6 | 49% | 90% | 0.9 | 0.9 | 0.8 |
| 8007 | Shell | Duct Sealing - Inadequate Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 7% | 367 | 0.11 | 20 | $450 | 100% | 40% | DUCT-7 | 49% | 90% | 0.9 | 0.9 | 0.8 |
| 8008 | Shell | Duct Sealing - Inadequate Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 7% | 367 | 0.11 | 20 | $450 | 100% | 100% | DUCT-8 | 49% | 90% | 0.9 | 0.9 | 0.8 |
| 8009 | Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 9% | 474 | 0.37 | 20 | $450 | 100% | 40% | DUCT-9 | 49% | 96% | 1.0 | 1.0 | 1.2 |
| 8010 | Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 7% | 373 | 0.27 | 20 | $450 | 100% | 100% | DUCT-10 | 49% | 96% | 1.0 | 1.0 | 0.9 |
| 8011 | Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 7% | 373 | 0.27 | 20 | $450 | 100% | 40% | DUCT-11 | 49% | 96% | 1.0 | 1.0 | 0.9 |
| 8012 | Shell | Duct Sealing/Insulation - Poor Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 7% | 373 | 0.27 | 20 | $450 | 100% | 100% | DUCT-12 | 49% | 96% | 1.0 | 1.0 | 0.9 |
| 8013 | Shell | Duct Sealing - Average Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 5% | 533 | 0.13 | 20 | $450 | 100% | 40% | DUCT-13 | 20% | 76% | 0.8 | 0.8 | 1.1 |
| 8014 | Shell | Duct Sealing - Average Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 5% | 533 | 0.13 | 20 | $450 | 100% | 100% | DUCT-14 | 20% | 76% | 0.8 | 0.8 | 1.1 |
| 8015 | Shell | Duct Sealing - Average Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 5% | 533 | 0.13 | 20 | $450 | 100% | 40% | DUCT-15 | 20% | 76% | 0.8 | 0.8 | 1.1 |
| 8016 | Shell | Duct Sealing - Average Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 5% | 533 | 0.13 | 20 | $450 | 100% | 100% | DUCT-16 | 20% | 76% | 0.8 | 0.8 | 1.1 |
| 8017 | Shell | Duct Sealing - Inadequate Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 7% | 744 | 0.11 | 20 | $450 | 100% | 40% | DUCT-17 | 20% | 90% | 0.9 | 0.9 | 1.4 |
| 8018 | Shell | Duct Sealing - Inadequate Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 7% | 744 | 0.11 | 20 | $450 | 100% | 100% | DUCT-18 | 20% | 90% | 0.9 | 0.9 | 1.4 |
| 8019 | Shell | Duct Sealing - Inadequate Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 7% | 744 | 0.11 | 20 | $450 | 100% | 40% | DUCT-19 | 20% | 90% | 0.9 | 0.9 | 1.4 |
| 8020 | Shell | Duct Sealing - Inadequate Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 7% | 744 | 0.11 | 20 | $450 | 100% | 100% | DUCT-20 | 20% | 90% | 0.9 | 0.9 | 1.4 |
| 8021 | Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 9% | 960 | 0.37 | 20 | $450 | 100% | 40% | DUCT-21 | 20% | 96% | 1.0 | 1.0 | 2.1 |
| 8022 | Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 7% | 755 | 0.27 | 20 | $450 | 100% | 100% | DUCT-22 | 20% | 96% | 1.0 | 1.0 | 1.6 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8023 | Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 7% | 755 | 0.27 | 20 | $450 | 100% | 40% | DUCT-23 | 20% | 96% | 1.0 | 1.0 | 1.6 |
| 8024 | Shell | Duct Sealing/Insulation - Poor Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 7% | 755 | 0.27 | 20 | $450 | 100% | 100% | DUCT-24 | 20% | 96% | 1.0 | 1.0 | 1.6 |
| 8025 | Shell | Duct Sealing - Average Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 5% | 99 | 0.13 | 20 | $450 | 100% | 40% | DUCT-25 | 19% | 76% | 0.8 | 0.8 | 0.3 |
| 8026 | Shell | Duct Sealing - Average Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 5% | 99 | 0.13 | 20 | $450 | 100% | 100% | DUCT-26 | 19% | 76% | 0.8 | 0.8 | 0.3 |
| 8027 | Shell | Duct Sealing - Average Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 5% | 99 | 0.13 | 20 | $450 | 100% | 40% | DUCT-27 | 19% | 76% | 0.8 | 0.8 | 0.3 |
| 8028 | Shell | Duct Sealing - Average Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 5% | 99 | 0.13 | 20 | $450 | 100% | 100% | DUCT-28 | 19% | 76% | 0.8 | 0.8 | 0.3 |
| 8029 | Shell | Duct Sealing - Inadequate Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 7% | 138 | 0.11 | 20 | $450 | 100% | 40% | DUCT-29 | 19% | 90% | 0.9 | 0.9 | 0.4 |
| 8030 | Shell | Duct Sealing - Inadequate Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 7% | 138 | 0.11 | 20 | $450 | 100% | 100% | DUCT-30 | 19% | 90% | 0.9 | 0.9 | 0.4 |
| 8031 | Shell | Duct Sealing - Inadequate Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 7% | 138 | 0.11 | 20 | $450 | 100% | 40% | DUCT-31 | 19% | 90% | 0.9 | 0.9 | 0.4 |
| 8032 | Shell | Duct Sealing - Inadequate Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 7% | 138 | 0.11 | 20 | $450 | 100% | 100% | DUCT-32 | 19% | 90% | 0.9 | 0.9 | 0.4 |
| 8033 | Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 9% | 178 | 0.37 | 20 | $450 | 100% | 40% | DUCT-33 | 19% | 96% | 1.0 | 1.0 | 0.7 |
| 8034 | Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 7% | 140 | 0.27 | 20 | $450 | 100% | 100% | DUCT-34 | 19% | 96% | 1.0 | 1.0 | 0.5 |
| 8035 | Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 7% | 140 | 0.27 | 20 | $450 | 100% | 40% | DUCT-35 | 19% | 96% | 1.0 | 1.0 | 0.5 |
| 8036 | Shell | Duct Sealing/Insulation - Poor Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 7% | 140 | 0.27 | 20 | $450 | 100% | 100% | DUCT-36 | 19% | 96% | 1.0 | 1.0 | 0.5 |
| 8037 | Shell | Wall Insulation - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 9% | 509 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-1 | 49% | 80% | 0.9 | 0.8 | 0.2 |
| 8038 | Shell | Wall Insulation - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 5% | 295 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-2 | 49% | 80% | 0.9 | 0.8 | 0.1 |
| 8039 | Shell | Wall Insulation - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 5% | 295 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-3 | 49% | 80% | 0.9 | 0.8 | 0.1 |
| 8040 | Shell | Wall Insulation - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 5% | 295 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-4 | 49% | 80% | 0.9 | 0.8 | 0.1 |
| 8041 | Shell | Wall Insulation - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 16% | 559 | 0.00 | 20 | $969 | 100% | 40% | WALL-5 | 47% | 80% | 0.9 | 0.8 | 0.5 |
| 8042 | Shell | Wall Insulation - Heat pump | Low Income | MF | LI | Retrofit | 3,396 | 11% | 385 | 0.00 | 20 | $969 | 100% | 100% | WALL-6 | 47% | 80% | 0.9 | 0.8 | 0.3 |
| 8043 | Shell | Wall Insulation - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 8% | 899 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-7 | 20% | 80% | 0.9 | 0.8 | 0.3 |
| 8044 | Shell | Wall Insulation - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 5% | 521 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-8 | 20% | 80% | 0.9 | 0.8 | 0.2 |
| 8045 | Shell | Wall Insulation - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 5% | 521 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-9 | 20% | 80% | 0.9 | 0.8 | 0.2 |
| 8046 | Shell | Wall Insulation - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 5% | 521 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-10 | 20% | 80% | 0.9 | 0.8 | 0.2 |
| 8047 | Shell | Wall Insulation - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 12% | 420 | 0.00 | 20 | $969 | 100% | 40% | WALL-11 | 47% | 80% | 0.9 | 0.8 | 0.3 |
| 8048 | Shell | Wall Insulation - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 8% | 288 | 0.00 | 20 | $969 | 100% | 100% | WALL-12 | 47% | 80% | 0.9 | 0.8 | 0.2 |
| 8049 | Shell | Wall Insulation - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 3% | 62 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-13 | 19% | 80% | 0.9 | 0.8 | 0.1 |
| 8050 | Shell | Wall Insulation - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 2% | 39 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-14 | 19% | 80% | 0.9 | 0.8 | 0.1 |
| 8051 | Shell | Wall Insulation - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 2% | 39 | 0.00 | 20 | $2,254 | 100% | 40% | WALL-15 | 19% | 80% | 0.9 | 0.8 | 0.1 |
| 8052 | Shell | Wall Insulation - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 2% | 39 | 0.00 | 20 | $2,254 | 100% | 100% | WALL-16 | 19% | 80% | 0.9 | 0.8 | 0.1 |
| 8053 | Shell | Wall Insulation - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 8% | 61 | 0.00 | 20 | $969 | 100% | 40% | WALL-17 | 15% | 80% | 0.9 | 0.8 | 0.3 |
| 8054 | Shell | Wall Insulation - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 5% | 39 | 0.00 | 20 | $969 | 100% | 100% | WALL-18 | 15% | 80% | 0.9 | 0.8 | 0.2 |
| 8055 | Shell | Air Sealing Average Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 11% | 618 | 0.18 | 20 | $200 | 100% | 40% | AIR-1 | 49% | 76% | 0.8 | 0.8 | 2.9 |
| 8056 | Shell | Air Sealing Average Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 11% | 618 | 0.18 | 20 | $200 | 100% | 100% | AIR-2 | 49% | 76% | 0.8 | 0.8 | 2.9 |
| 8057 | Shell | Air Sealing Average Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 11% | 618 | 0.18 | 20 | $200 | 100% | 40% | AIR-3 | 49% | 76% | 0.8 | 0.8 | 2.9 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8058 | Shell | Air Sealing Average Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 11% | 618 | 0.18 | 20 | $200 | 100% | 100% | AIR-4 | 49% | 76% | 0.8 | 0.8 | 2.9 |
| 8059 | Shell | Air Sealing Average Sealing - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 17% | 346 | 0.09 | 20 | $200 | 100% | 40% | AIR-5 | 36% | 76% | 0.8 | 0.8 | 1.6 |
| 8060 | Shell | Air Sealing Average Sealing - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 17% | 346 | 0.09 | 20 | $200 | 100% | 100% | AIR-6 | 36% | 76% | 0.8 | 0.8 | 1.6 |
| 8061 | Shell | Air Sealing Inadequate Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 13% | 728 | 0.25 | 20 | $200 | 100% | 40% | AIR-7 | 49% | 90% | 0.9 | 0.9 | 3.5 |
| 8062 | Shell | Air Sealing Inadequate Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 13% | 728 | 0.25 | 20 | $200 | 100% | 100% | AIR-8 | 49% | 90% | 0.9 | 0.9 | 3.5 |
| 8063 | Shell | Air Sealing Inadequate Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 13% | 728 | 0.25 | 20 | $200 | 100% | 40% | AIR-9 | 49% | 90% | 0.9 | 0.9 | 3.5 |
| 8064 | Shell | Air Sealing Inadequate Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 13% | 728 | 0.25 | 20 | $200 | 100% | 100% | AIR-10 | 49% | 90% | 0.9 | 0.9 | 3.5 |
| 8065 | Shell | Air Sealing Inadequate Sealing - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 20% | 407 | 0.13 | 20 | $200 | 100% | 40% | AIR-11 | 36% | 90% | 0.9 | 0.9 | 1.9 |
| 8066 | Shell | Air Sealing Inadequate Sealing - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 20% | 407 | 0.13 | 20 | $200 | 100% | 100% | AIR-12 | 36% | 90% | 0.9 | 0.9 | 1.9 |
| 8067 | Shell | Air Sealing Poor Sealing - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 19% | 1,025 | 0.39 | 20 | $200 | 100% | 40% | AIR-13 | 49% | 96% | 1.0 | 1.0 | 5.0 |
| 8068 | Shell | Air Sealing Poor Sealing - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 19% | 1,025 | 0.39 | 20 | $200 | 100% | 100% | AIR-14 | 49% | 96% | 1.0 | 1.0 | 5.0 |
| 8069 | Shell | Air Sealing Poor Sealing - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 19% | 1,025 | 0.39 | 20 | $200 | 100% | 40% | AIR-15 | 49% | 96% | 1.0 | 1.0 | 5.0 |
| 8070 | Shell | Air Sealing Poor Sealing - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 19% | 1,025 | 0.39 | 20 | $200 | 100% | 100% | AIR-16 | 49% | 96% | 1.0 | 1.0 | 5.0 |
| 8071 | Shell | Air Sealing Poor Sealing - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 28% | 573 | 0.19 | 20 | $200 | 100% | 40% | AIR-17 | 36% | 96% | 1.0 | 1.0 | 2.7 |
| 8072 | Shell | Air Sealing Poor Sealing - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 28% | 573 | 0.19 | 20 | $200 | 100% | 100% | AIR-18 | 36% | 96% | 1.0 | 1.0 | 2.7 |
| 8073 | Shell | Air Sealing Average Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 14% | 1,527 | 0.21 | 20 | $200 | 100% | 40% | AIR-19 | 20% | 76% | 0.8 | 0.8 | 6.6 |
| 8074 | Shell | Air Sealing Average Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 14% | 1,527 | 0.21 | 20 | $200 | 100% | 100% | AIR-20 | 20% | 76% | 0.8 | 0.8 | 6.6 |
| 8075 | Shell | Air Sealing Average Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 14% | 1,527 | 0.21 | 20 | $200 | 100% | 40% | AIR-21 | 20% | 76% | 0.8 | 0.8 | 6.6 |
| 8076 | Shell | Air Sealing Average Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 14% | 1,527 | 0.21 | 20 | $200 | 100% | 100% | AIR-22 | 20% | 76% | 0.8 | 0.8 | 6.6 |
| 8077 | Shell | Air Sealing Average Sealing - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 24% | 824 | 0.11 | 20 | $200 | 100% | 40% | AIR-23 | 47% | 76% | 0.8 | 0.8 | 3.6 |
| 8078 | Shell | Air Sealing Average Sealing - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 24% | 824 | 0.11 | 20 | $200 | 100% | 100% | AIR-24 | 47% | 76% | 0.8 | 0.8 | 3.6 |
| 8079 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 16% | 1,763 | 0.29 | 20 | $200 | 100% | 40% | AIR-25 | 20% | 90% | 0.9 | 0.9 | 7.8 |
| 8080 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 16% | 1,763 | 0.29 | 20 | $200 | 100% | 100% | AIR-26 | 20% | 90% | 0.9 | 0.9 | 7.8 |
| 8081 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 16% | 1,763 | 0.29 | 20 | $200 | 100% | 40% | AIR-27 | 20% | 90% | 0.9 | 0.9 | 7.8 |
| 8082 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 16% | 1,763 | 0.29 | 20 | $200 | 100% | 100% | AIR-28 | 20% | 90% | 0.9 | 0.9 | 7.8 |
| 8083 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 28% | 952 | 0.15 | 20 | $200 | 100% | 40% | AIR-29 | 47% | 90% | 0.9 | 0.9 | 4.2 |
| 8084 | Shell | Air Sealing Inadequate Sealing - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 28% | 952 | 0.15 | 20 | $200 | 100% | 100% | AIR-30 | 47% | 90% | 0.9 | 0.9 | 4.2 |
| 8085 | Shell | Air Sealing Poor Sealing - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 20% | 2,206 | 0.38 | 20 | $200 | 100% | 40% | AIR-31 | 20% | 96% | 1.0 | 1.0 | 9.7 |
| 8086 | Shell | Air Sealing Poor Sealing - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 20% | 2,206 | 0.38 | 20 | $200 | 100% | 100% | AIR-32 | 20% | 96% | 1.0 | 1.0 | 9.7 |
| 8087 | Shell | Air Sealing Poor Sealing - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 20% | 2,206 | 0.38 | 20 | $200 | 100% | 40% | AIR-33 | 20% | 96% | 1.0 | 1.0 | 9.7 |
| 8088 | Shell | Air Sealing Poor Sealing - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 20% | 2,206 | 0.38 | 20 | $200 | 100% | 100% | AIR-34 | 20% | 96% | 1.0 | 1.0 | 9.7 |
| 8089 | Shell | Air Sealing Poor Sealing - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 35% | 1,192 | 0.19 | 20 | $200 | 100% | 40% | AIR-35 | 47% | 96% | 1.0 | 1.0 | 5.2 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8090 | Shell | Air Sealing Poor Sealing - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 35% | 1,192 | 0.19 | 20 | $200 | 100% | 100% | AIR-36 | 47% | 96% | 1.0 | 1.0 | 5.2 |
| 8091 | Shell | Air Sealing - Average Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 7% | 146 | 0.35 | 20 | $200 | 100% | 40% | AIR-37 | 19% | 76% | 0.8 | 0.8 | 1.4 |
| 8092 | Shell | Air Sealing - Average Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 7% | 146 | 0.35 | 20 | $200 | 100% | 100% | AIR-38 | 19% | 76% | 0.8 | 0.8 | 1.4 |
| 8093 | Shell | Air Sealing - Average Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 7% | 146 | 0.35 | 20 | $200 | 100% | 40% | AIR-39 | 19% | 76% | 0.8 | 0.8 | 1.4 |
| 8094 | Shell | Air Sealing - Average Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 7% | 146 | 0.35 | 20 | $200 | 100% | 100% | AIR-40 | 19% | 76% | 0.8 | 0.8 | 1.4 |
| 8095 | Shell | Air Sealing - Average Sealing - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 10% | 76 | 0.18 | 20 | $200 | 100% | 40% | AIR-41 | 15% | 76% | 0.8 | 0.8 | 0.7 |
| 8096 | Shell | Air Sealing - Average Sealing - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 10% | 76 | 0.18 | 20 | $200 | 100% | 100% | AIR-42 | 15% | 76% | 0.8 | 0.8 | 0.7 |
| 8097 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 13% | 261 | 0.39 | 20 | $200 | 100% | 40% | AIR-43 | 19% | 90% | 0.9 | 0.9 | 2.0 |
| 8098 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 13% | 261 | 0.39 | 20 | $200 | 100% | 100% | AIR-44 | 19% | 90% | 0.9 | 0.9 | 2.0 |
| 8099 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 13% | 261 | 0.39 | 20 | $200 | 100% | 40% | AIR-45 | 19% | 90% | 0.9 | 0.9 | 2.0 |
| 8100 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 13% | 261 | 0.39 | 20 | $200 | 100% | 100% | AIR-46 | 19% | 90% | 0.9 | 0.9 | 2.0 |
| 8101 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 18% | 136 | 0.20 | 20 | $200 | 100% | 40% | AIR-47 | 15% | 90% | 0.9 | 0.9 | 1.0 |
| 8102 | Shell | Air Sealing - Inadequate Sealing - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 18% | 136 | 0.20 | 20 | $200 | 100% | 100% | AIR-48 | 15% | 90% | 0.9 | 0.9 | 1.0 |
| 8103 | Shell | Air Sealing - Poor Sealing - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 9% | 181 | 0.31 | 20 | $200 | 100% | 40% | AIR-49 | 19% | 96% | 1.0 | 1.0 | 1.5 |
| 8104 | Shell | Air Sealing - Poor Sealing - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 9% | 181 | 0.31 | 20 | $200 | 100% | 100% | AIR-50 | 19% | 96% | 1.0 | 1.0 | 1.5 |
| 8105 | Shell | Air Sealing - Poor Sealing - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 9% | 181 | 0.31 | 20 | $200 | 100% | 40% | AIR-51 | 19% | 96% | 1.0 | 1.0 | 1.5 |
| 8106 | Shell | Air Sealing - Poor Sealing - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 9% | 181 | 0.31 | 20 | $200 | 100% | 100% | AIR-52 | 19% | 96% | 1.0 | 1.0 | 1.5 |
| 8107 | Shell | Air Sealing - Poor Sealing - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 12% | 94 | 0.16 | 20 | $200 | 100% | 40% | AIR-53 | 15% | 96% | 1.0 | 1.0 | 0.7 |
| 8108 | Shell | Air Sealing - Poor Sealing - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 12% | 94 | 0.16 | 20 | $200 | 100% | 100% | AIR-54 | 15% | 96% | 1.0 | 1.0 | 0.7 |
| 8109 | Shell | Attic Insulation - Average Insulation - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 2% | 118 | 0.08 | 20 | $898 | 100% | 40% | ATTIC-1 | 49% | 73% | 0.8 | 0.8 | 0.1 |
| 8110 | Shell | Attic Insulation - Average Insulation - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 2% | 118 | 0.08 | 20 | $898 | 100% | 100% | ATTIC-2 | 49% | 73% | 0.8 | 0.8 | 0.1 |
| 8111 | Shell | Attic Insulation - Inadequate Insulation - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 4% | 222 | 0.14 | 20 | $1,597 | 100% | 40% | ATTIC-3 | 49% | 73% | 0.8 | 0.8 | 0.2 |
| 8112 | Shell | Attic Insulation - Inadequate Insulation - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 4% | 222 | 0.14 | 20 | $1,597 | 100% | 100% | ATTIC-4 | 49% | 73% | 0.8 | 0.8 | 0.2 |
| 8113 | Shell | Attic Insulation - Poor Insulation - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 18% | 1,017 | 0.38 | 20 | $1,597 | 100% | 40% | ATTIC-5 | 49% | 80% | 0.9 | 0.8 | 0.6 |
| 8114 | Shell | Attic Insulation - Poor Insulation - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 18% | 1,006 | 0.42 | 20 | $1,597 | 100% | 100% | ATTIC-6 | 49% | 80% | 0.9 | 0.8 | 0.6 |
| 8115 | Shell | Attic Insulation - Average Insulation - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 2% | 239 | 0.08 | 20 | $898 | 100% | 40% | ATTIC-7 | 20% | 73% | 0.8 | 0.8 | 0.3 |
| 8116 | Shell | Attic Insulation - Average Insulation - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 2% | 239 | 0.08 | 20 | $898 | 100% | 100% | ATTIC-8 | 20% | 73% | 0.8 | 0.8 | 0.3 |
| 8117 | Shell | Attic Insulation - Inadequate Insulation - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 4% | 450 | 0.14 | 20 | $1,597 | 100% | 40% | ATTIC-9 | 20% | 73% | 0.8 | 0.8 | 0.3 |
| 8118 | Shell | Attic Insulation - Inadequate Insulation - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 4% | 450 | 0.14 | 20 | $1,597 | 100% | 100% | ATTIC-10 | 20% | 73% | 0.8 | 0.8 | 0.3 |
| 8119 | Shell | Attic Insulation - Poor Insulation - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 18% | 2,060 | 0.38 | 20 | $1,597 | 100% | 40% | ATTIC-11 | 20% | 80% | 0.9 | 0.8 | 1.1 |
| 8120 | Shell | Attic Insulation - Poor Insulation - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 18% | 2,038 | 0.42 | 20 | $1,597 | 100% | 100% | ATTIC-12 | 20% | 80% | 0.9 | 0.8 | 1.1 |
| 8121 | Shell | Attic Insulation - Average Insulation - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 2% | 44 | 0.08 | 20 | $898 | 100% | 40% | ATTIC-13 | 19% | 73% | 0.8 | 0.8 | 0.1 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8122 | Shell | Attic Insulation - Average Insulation - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 2% | 44 | 0.08 | 20 | $898 | 100% | 100% | ATTIC-14 | 19% | 73% | 0.8 | 0.8 | 0.1 |
| 8123 | Shell | Attic Insulation - Inadequate Insulation - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 4% | 84 | 0.14 | 20 | $1,597 | 100% | 40% | ATTIC-15 | 19% | 73% | 0.8 | 0.8 | 0.1 |
| 8124 | Shell | Attic Insulation - Inadequate Insulation - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 4% | 84 | 0.14 | 20 | $1,597 | 100% | 100% | ATTIC-16 | 19% | 73% | 0.8 | 0.8 | 0.1 |
| 8125 | Shell | Attic Insulation - Poor Insulation - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 18% | 383 | 0.38 | 20 | $1,597 | 100% | 40% | ATTIC-17 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8126 | Shell | Attic Insulation - Poor Insulation - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 18% | 379 | 0.42 | 20 | $1,597 | 100% | 100% | ATTIC-18 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8127 | Shell | Radiant Barrier - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 15% | 831 | 0.14 | 25 | $720 | 100% | 40% | RB-1 | 49% | 75% | 0.8 | 0.8 | 1.2 |
| 8128 | Shell | Radiant Barrier - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 15% | 831 | 0.14 | 25 | $720 | 100% | 100% | RB-2 | 49% | 75% | 0.8 | 0.8 | 1.2 |
| 8129 | Shell | Radiant Barrier - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 8% | 916 | 0.14 | 25 | $720 | 100% | 40% | RB-3 | 20% | 75% | 0.8 | 0.8 | 1.3 |
| 8130 | Shell | Radiant Barrier - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 8% | 916 | 0.14 | 25 | $720 | 100% | 100% | RB-4 | 20% | 75% | 0.8 | 0.8 | 1.3 |
| 8131 | Shell | Radiant Barrier - Gas furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 15% | 313 | 0.14 | 25 | $720 | 100% | 40% | RB-5 | 19% | 75% | 0.8 | 0.8 | 0.5 |
| 8132 | Shell | Radiant Barrier - Gas furnace | Low Income | SF | LI | Retrofit | 2,073 | 15% | 313 | 0.14 | 25 | $720 | 100% | 100% | RB-6 | 19% | 75% | 0.8 | 0.8 | 0.5 |
| 8133 | Shell | Cool Roof - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 40% | COOL-1 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8134 | Shell | Cool Roof - Heat pump | Low Income | SF | LI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 100% | COOL-2 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8135 | Shell | Cool Roof - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 40% | COOL-3 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8136 | Shell | Cool Roof - Electric furnace | Low Income | SF | LI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 100% | COOL-4 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8137 | Shell | Cool Roof - Gas furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 40% | COOL-5 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8138 | Shell | Cool Roof - Gas furnace | Low Income | SF | LI | Retrofit | 1,775 | 1% | 22 | 0.13 | 20 | $509 | 100% | 100% | COOL-6 | 23% | 75% | 0.8 | 0.8 | 0.1 |
| 8139 | Shell | ENERGY STAR Windows - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 6% | 340 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-1 | 49% | 70% | 0.8 | 0.8 | 0.0 |
| 8140 | Shell | ENERGY STAR Windows - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 6% | 340 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-2 | 49% | 70% | 0.8 | 0.8 | 0.0 |
| 8141 | Shell | ENERGY STAR Windows - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 6% | 340 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-3 | 49% | 70% | 0.8 | 0.8 | 0.0 |
| 8142 | Shell | ENERGY STAR Windows - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 6% | 340 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-4 | 49% | 70% | 0.8 | 0.8 | 0.0 |
| 8143 | Shell | ENERGY STAR Windows - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 9% | 184 | 0.12 | 20 | $7,232 | 100% | 40% | WINDOW-5 | 36% | 70% | 0.8 | 0.7 | 0.0 |
| 8144 | Shell | ENERGY STAR Windows - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 9% | 184 | 0.12 | 20 | $7,232 | 100% | 100% | WINDOW-6 | 36% | 70% | 0.8 | 0.8 | 0.0 |
| 8145 | Shell | ENERGY STAR Windows - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 5% | 573 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-7 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8146 | Shell | ENERGY STAR Windows - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 5% | 573 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-8 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8147 | Shell | ENERGY STAR Windows - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 5% | 573 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-9 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8148 | Shell | ENERGY STAR Windows - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 5% | 573 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-10 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8149 | Shell | ENERGY STAR Windows - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 9% | 319 | 0.12 | 20 | $7,232 | 100% | 40% | WINDOW-11 | 47% | 70% | 0.8 | 0.7 | 0.0 |
| 8150 | Shell | ENERGY STAR Windows - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 9% | 319 | 0.12 | 20 | $7,232 | 100% | 100% | WINDOW-12 | 47% | 70% | 0.8 | 0.8 | 0.0 |
| 8151 | Shell | ENERGY STAR Windows - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 6% | 117 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-13 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8152 | Shell | ENERGY STAR Windows - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 6% | 117 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-14 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8153 | Shell | ENERGY STAR Windows - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 6% | 117 | 0.25 | 20 | $11,300 | 100% | 40% | WINDOW-15 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8154 | Shell | ENERGY STAR Windows - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 6% | 117 | 0.25 | 20 | $11,300 | 100% | 100% | WINDOW-16 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8155 | Shell | ENERGY STAR Windows - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 8% | 59 | 0.12 | 20 | $7,232 | 100% | 40% | WINDOW-17 | 15% | 70% | 0.8 | 0.7 | 0.0 |
| 8156 | Shell | ENERGY STAR Windows - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 8% | 59 | 0.12 | 20 | $7,232 | 100% | 100% | WINDOW-18 | 15% | 70% | 0.8 | 0.8 | 0.0 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8157 | Shell | Basement Sidewall Insulation - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 8% | 438 | 0.97 | 20 | $696 | 100% | 40% | BASEMENT-1 | 49% | 80% | 0.9 | 0.8 | 1.2 |
| 8158 | Shell | Basement Sidewall Insulation - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 5% | 254 | 0.56 | 20 | $696 | 100% | 100% | BASEMENT-2 | 49% | 80% | 0.9 | 0.8 | 0.7 |
| 8159 | Shell | Basement Sidewall Insulation - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 5% | 502 | 0.29 | 20 | $696 | 100% | 40% | BASEMENT-3 | 20% | 80% | 0.9 | 0.8 | 0.8 |
| 8160 | Shell | Basement Sidewall Insulation - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 3% | 291 | 0.17 | 20 | $696 | 100% | 100% | BASEMENT-4 | 20% | 80% | 0.9 | 0.8 | 0.5 |
| 8161 | Shell | Basement Sidewall Insulation - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | -2% | -42 | -0.05 | 20 | $696 | 100% | 40% | BASEMENT-5 | 19% | 80% | 0.9 | 0.8 | 0.2 |
| 8162 | Shell | Basement Sidewall Insulation - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | -1% | -26 | -0.03 | 20 | $696 | 100% | 100% | BASEMENT-6 | 19% | 80% | 0.9 | 0.8 | 0.1 |
| 8163 | Shell | Floor Insulation Above Crawlspace - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 22% | 1,190 | 1.30 | 25 | $772 | 100% | 40% | CRAWL-1 | 49% | 80% | 0.9 | 0.8 | 2.4 |
| 8164 | Shell | Floor Insulation Above Crawlspace - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 13% | 734 | 0.80 | 25 | $476 | 100% | 100% | CRAWL-2 | 49% | 80% | 0.9 | 0.8 | 2.4 |
| 8165 | Shell | Floor Insulation Above Crawlspace - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 13% | 734 | 0.80 | 25 | $476 | 100% | 40% | CRAWL-3 | 49% | 80% | 0.9 | 0.8 | 2.4 |
| 8166 | Shell | Floor Insulation Above Crawlspace - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 13% | 734 | 0.80 | 25 | $476 | 100% | 100% | CRAWL-4 | 49% | 80% | 0.9 | 0.8 | 2.4 |
| 8167 | Shell | Floor Insulation Above Crawlspace - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 23% | 2,604 | 0.75 | 25 | $772 | 100% | 40% | CRAWL-5 | 20% | 80% | 0.9 | 0.8 | 3.7 |
| 8168 | Shell | Floor Insulation Above Crawlspace - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 14% | 1,606 | 0.46 | 25 | $476 | 100% | 100% | CRAWL-6 | 20% | 80% | 0.9 | 0.8 | 3.7 |
| 8169 | Shell | Floor Insulation Above Crawlspace - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 14% | 1,606 | 0.46 | 25 | $476 | 100% | 40% | CRAWL-7 | 20% | 80% | 0.9 | 0.8 | 3.7 |
| 8170 | Shell | Floor Insulation Above Crawlspace - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 14% | 1,606 | 0.46 | 25 | $476 | 100% | 100% | CRAWL-8 | 20% | 80% | 0.9 | 0.8 | 3.7 |
| 8171 | Shell | Floor Insulation Above Crawlspace - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 11% | 221 | 0.12 | 25 | $772 | 100% | 40% | CRAWL-9 | 19% | 80% | 0.9 | 0.8 | 0.9 |
| 8172 | Shell | Floor Insulation Above Crawlspace - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 7% | 136 | 0.07 | 25 | $476 | 100% | 100% | CRAWL-10 | 19% | 80% | 0.9 | 0.8 | 0.9 |
| 8173 | Shell | Floor Insulation Above Crawlspace - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 7% | 136 | 0.07 | 25 | $476 | 100% | 40% | CRAWL-11 | 19% | 80% | 0.9 | 0.8 | 0.9 |
| 8174 | Shell | Floor Insulation Above Crawlspace - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 7% | 136 | 0.07 | 25 | $476 | 100% | 100% | CRAWL-12 | 19% | 80% | 0.9 | 0.8 | 0.9 |
| 8175 | Shell | ENERGY STAR Door - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 5% | 271 | 0.02 | 20 | $1,275 | 100% | 40% | DOOR-1 | 49% | 75% | 0.8 | 0.8 | 0.2 |
| 8176 | Shell | ENERGY STAR Door - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 5% | 271 | 0.02 | 20 | $1,275 | 100% | 100% | DOOR-2 | 49% | 75% | 0.8 | 0.8 | 0.2 |
| 8177 | Shell | ENERGY STAR Door - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 5% | 271 | 0.02 | 20 | $1,275 | 100% | 40% | DOOR-3 | 49% | 75% | 0.8 | 0.8 | 0.2 |
| 8178 | Shell | ENERGY STAR Door - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 5% | 271 | 0.02 | 20 | $1,275 | 100% | 100% | DOOR-4 | 49% | 75% | 0.8 | 0.8 | 0.2 |
| 8179 | Shell | ENERGY STAR Door - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 8% | 151 | 0.01 | 20 | $1,275 | 100% | 40% | DOOR-5 | 36% | 75% | 0.8 | 0.8 | 0.1 |
| 8180 | Shell | ENERGY STAR Door - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 8% | 151 | 0.01 | 20 | $1,275 | 100% | 100% | DOOR-6 | 36% | 75% | 0.8 | 0.8 | 0.1 |
| 8181 | Shell | ENERGY STAR Door - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 2% | 184 | 0.01 | 20 | $1,275 | 100% | 40% | DOOR-7 | 20% | 75% | 0.8 | 0.8 | 0.1 |
| 8182 | Shell | ENERGY STAR Door - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 2% | 184 | 0.01 | 20 | $1,275 | 100% | 100% | DOOR-8 | 20% | 75% | 0.8 | 0.8 | 0.1 |
| 8183 | Shell | ENERGY STAR Door - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 2% | 184 | 0.01 | 20 | $1,275 | 100% | 40% | DOOR-9 | 20% | 75% | 0.8 | 0.8 | 0.1 |
| 8184 | Shell | ENERGY STAR Door - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 2% | 184 | 0.01 | 20 | $1,275 | 100% | 100% | DOOR-10 | 20% | 75% | 0.8 | 0.8 | 0.1 |
| 8185 | Shell | ENERGY STAR Door - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 3% | 106 | 0.01 | 20 | $1,275 | 100% | 40% | DOOR-11 | 47% | 75% | 0.8 | 0.8 | 0.1 |
| 8186 | Shell | ENERGY STAR Door - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 3% | 106 | 0.01 | 20 | $1,275 | 100% | 100% | DOOR-12 | 47% | 75% | 0.8 | 0.8 | 0.1 |
| 8187 | Shell | ENERGY STAR Door - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 1% | 18 | 0.02 | 20 | $1,275 | 100% | 40% | DOOR-13 | 19% | 75% | 0.8 | 0.8 | 0.0 |
| 8188 | Shell | ENERGY STAR Door - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 1% | 18 | 0.02 | 20 | $1,275 | 100% | 100% | DOOR-14 | 19% | 75% | 0.8 | 0.8 | 0.0 |
| 8189 | Shell | ENERGY STAR Door - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 1% | 18 | 0.02 | 20 | $1,275 | 100% | 40% | DOOR-15 | 19% | 75% | 0.8 | 0.8 | 0.0 |
| 8190 | Shell | ENERGY STAR Door - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 1% | 18 | 0.02 | 20 | $1,275 | 100% | 100% | DOOR-16 | 19% | 75% | 0.8 | 0.8 | 0.0 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permutation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8191 | Shell | ENERGY STAR Door - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 1% | 9 | 0.01 | 20 | $1,275 | 100% | 40% | DOOR-17 | 15% | 75% | 0.8 | 0.8 | 0.0 |
| 8192 | Shell | ENERGY STAR Door - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 1% | 9 | 0.01 | 20 | $1,275 | 100% | 100% | DOOR-18 | 15% | 75% | 0.8 | 0.8 | 0.0 |
| 8193 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 16% | 854 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-1 | 49% | 70% | 0.8 | 0.8 | 0.1 |
| 8194 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Low Income | SF | LI | Retrofit | 5,508 | 16% | 854 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-2 | 49% | 70% | 0.8 | 0.8 | 0.1 |
| 8195 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 16% | 854 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-3 | 49% | 70% | 0.8 | 0.8 | 0.1 |
| 8196 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Low Income | MH | LI | Retrofit | 5,508 | 16% | 854 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-4 | 49% | 70% | 0.8 | 0.8 | 0.1 |
| 8197 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 16% | 313 | 0.23 | 7 | $4,339 | 100% | 40% | SWC-5 | 36% | 70% | 0.8 | 0.7 | 0.0 |
| 8198 | Shell | Smart Window Coverings - Film/Transformer - Heat pump | Low Income | MF | LI | Retrofit | 2,018 | 16% | 313 | 0.23 | 7 | $4,339 | 100% | 100% | SWC-6 | 36% | 70% | 0.8 | 0.8 | 0.0 |
| 8199 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 16% | 1,730 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-7 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8200 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Low Income | SF | LI | Retrofit | 11,159 | 16% | 1,730 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-8 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8201 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 16% | 1,730 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-9 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8202 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Low Income | MH | LI | Retrofit | 11,159 | 16% | 1,730 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-10 | 20% | 70% | 0.8 | 0.8 | 0.1 |
| 8203 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 16% | 526 | 0.23 | 7 | $4,339 | 100% | 40% | SWC-11 | 47% | 70% | 0.8 | 0.7 | 0.1 |
| 8204 | Shell | Smart Window Coverings - Film/Transformer - Electric furnace | Low Income | MF | LI | Retrofit | 3,396 | 16% | 526 | 0.23 | 7 | $4,339 | 100% | 100% | SWC-12 | 47% | 70% | 0.8 | 0.8 | 0.1 |
| 8205 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 16% | 321 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-13 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8206 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Low Income | SF | LI | Retrofit | 2,073 | 16% | 321 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-14 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8207 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 16% | 321 | 0.35 | 7 | $6,780 | 100% | 40% | SWC-15 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8208 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Low Income | MH | LI | Retrofit | 2,073 | 16% | 321 | 0.35 | 7 | $6,780 | 100% | 100% | SWC-16 | 19% | 70% | 0.8 | 0.8 | 0.0 |
| 8209 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 16% | 120 | 0.23 | 7 | $4,339 | 100% | 40% | SWC-17 | 15% | 70% | 0.8 | 0.7 | 0.0 |
| 8210 | Shell | Smart Window Coverings - Film/Transformer - Gas Heating | Low Income | MF | LI | Retrofit | 774 | 16% | 120 | 0.23 | 7 | $4,339 | 100% | 100% | SWC-18 | 15% | 70% | 0.8 | 0.8 | 0.0 |
| 8211 | Shell | Thin Triple Windows - electric furnace base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 7% | 782 | 0.27 | 40 | $6,350 | 100% | 40% | WINDOW-1 | 20% | 70% | 0.8 | 0.8 | 0.2 |
| 8212 | Shell | Thin Triple Windows - electric furnace base | Low Income | SF | LI | Retrofit | 11,159 | 6% | 626 | 0.22 | 40 | $5,080 | 100% | 100% | WINDOW-2 | 20% | 70% | 0.8 | 0.8 | 0.2 |
| 8213 | Shell | Thin Triple Windows - electric furnace base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 6% | 626 | 0.22 | 40 | $5,080 | 100% | 40% | WINDOW-3 | 20% | 70% | 0.8 | 0.8 | 0.2 |
| 8214 | Shell | Thin Triple Windows - electric furnace base | Low Income | MH | LI | Retrofit | 11,159 | 6% | 626 | 0.22 | 40 | $5,080 | 100% | 100% | WINDOW-4 | 20% | 70% | 0.8 | 0.8 | 0.2 |
| 8215 | Shell | Thin Triple Windows - electric furnace base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 17% | 576 | 0.16 | 40 | $3,810 | 100% | 40% | WINDOW-5 | 47% | 70% | 0.8 | 0.7 | 0.2 |
| 8216 | Shell | Thin Triple Windows - electric furnace base | Low Income | MF | LI | Retrofit | 3,396 | 11% | 384 | 0.11 | 40 | $2,540 | 100% | 100% | WINDOW-6 | 47% | 70% | 0.8 | 0.8 | 0.2 |
| 8217 | Shell | Thin Triple Windows - heat pump base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 14% | 746 | 0.28 | 40 | $6,350 | 100% | 40% | WINDOW-7 | 49% | 70% | 0.8 | 0.8 | 0.2 |
| 8218 | Shell | Thin Triple Windows - heat pump base | Low Income | SF | LI | Retrofit | 5,508 | 11% | 597 | 0.22 | 40 | $5,080 | 100% | 100% | WINDOW-8 | 49% | 70% | 0.8 | 0.8 | 0.2 |
| 8219 | Shell | Thin Triple Windows - heat pump base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 11% | 597 | 0.22 | 40 | $5,080 | 100% | 40% | WINDOW-9 | 49% | 70% | 0.8 | 0.8 | 0.2 |
| 8220 | Shell | Thin Triple Windows - heat pump base | Low Income | MH | LI | Retrofit | 5,508 | 11% | 597 | 0.22 | 40 | $5,080 | 100% | 100% | WINDOW-1( | 49% | 70% | 0.8 | 0.8 | 0.2 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8221 | Shell | Thin Triple Windows - heat pump base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 26% | 534 | 0.17 | 40 | $3,810 | 100% | 40% | WINDOW-11 | 36% | 70% | 0.8 | 0.7 | 0.2 |
| 8222 | Shell | Thin Triple Windows - heat pump base | Low Income | MF | LI | Retrofit | 2,018 | 18% | 356 | 0.11 | 40 | $2,540 | 100% | 100% | WINDOW-12 | 36% | 70% | 0.8 | 0.8 | 0.2 |
| 8223 | Shell | Thin Triple Windows - gas heat and electric cool base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 8% | 156 | 0.06 | 40 | $6,350 | 100% | 40% | WINDOW-13 | 19% | 70% | 0.8 | 0.8 | 0.1 |
| 8224 | Shell | Thin Triple Windows - gas heat and electric cool base | Low Income | SF | LI | Retrofit | 2,073 | 6% | 124 | 0.04 | 40 | $5,080 | 100% | 100% | WINDOW-14 | 19% | 70% | 0.8 | 0.8 | 0.1 |
| 8225 | Shell | Thin Triple Windows - gas heat and electric cool base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 6% | 124 | 0.04 | 40 | $5,080 | 100% | 40% | WINDOW-15 | 19% | 70% | 0.8 | 0.8 | 0.1 |
| 8226 | Shell | Thin Triple Windows - gas heat and electric cool base | Low Income | MH | LI | Retrofit | 2,073 | 6% | 124 | 0.04 | 40 | $5,080 | 100% | 100% | WINDOW-16 | 19% | 70% | 0.8 | 0.8 | 0.1 |
| 8227 | Shell | Thin Triple Windows - gas heat and electric cool base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 13% | 98 | 0.03 | 40 | $3,810 | 100% | 40% | WINDOW-17 | 15% | 70% | 0.8 | 0.7 | 0.1 |
| 8228 | Shell | Thin Triple Windows - gas heat and electric cool base | Low Income | MF | LI | Retrofit | 774 | 8% | 65 | 0.02 | 40 | $2,540 | 100% | 100% | WINDOW-18 | 15% | 70% | 0.8 | 0.8 | 0.1 |
| 8229 | Shell | Advanced Walls - electric furnace base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 11,159 | 10% | 1,116 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-1 | 20% | 80% | 0.9 | 0.8 | 0.4 |
| 8230 | Shell | Advanced Walls - electric furnace base | Low Income | SF | LI | Retrofit | 11,159 | 10% | 1,116 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-2 | 20% | 80% | 0.9 | 0.8 | 0.4 |
| 8231 | Shell | Advanced Walls - electric furnace base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 11,159 | 10% | 1,116 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-3 | 20% | 80% | 0.9 | 0.8 | 0.4 |
| 8232 | Shell | Advanced Walls - electric furnace base | Low Income | MH | LI | Retrofit | 11,159 | 10% | 1,116 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-4 | 20% | 80% | 0.9 | 0.8 | 0.4 |
| 8233 | Shell | Advanced Walls - electric furnace base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,396 | 10% | 340 | 0.23 | 20 | $1,581 | 100% | 40% | WALL-5 | 47% | 80% | 0.9 | 0.8 | 0.2 |
| 8234 | Shell | Advanced Walls - electric furnace base | Low Income | MF | LI | Retrofit | 3,396 | 10% | 340 | 0.23 | 20 | $1,581 | 100% | 100% | WALL-6 | 47% | 80% | 0.9 | 0.8 | 0.2 |
| 8235 | Shell | Advanced Walls - heat pump base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 5,508 | 10% | 551 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-7 | 49% | 80% | 0.9 | 0.8 | 0.2 |
| 8236 | Shell | Advanced Walls - heat pump base | Low Income | SF | LI | Retrofit | 5,508 | 10% | 551 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-8 | 49% | 80% | 0.9 | 0.8 | 0.2 |
| 8237 | Shell | Advanced Walls - heat pump base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 5,508 | 10% | 551 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-9 | 49% | 80% | 0.9 | 0.8 | 0.2 |
| 8238 | Shell | Advanced Walls - heat pump base | Low Income | MH | LI | Retrofit | 5,508 | 10% | 551 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-10 | 49% | 80% | 0.9 | 0.8 | 0.2 |
| 8239 | Shell | Advanced Walls - heat pump base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,018 | 10% | 202 | 0.23 | 20 | $1,581 | 100% | 40% | WALL-11 | 36% | 80% | 0.9 | 0.8 | 0.2 |
| 8240 | Shell | Advanced Walls - heat pump base | Low Income | MF | LI | Retrofit | 2,018 | 10% | 202 | 0.23 | 20 | $1,581 | 100% | 100% | WALL-12 | 36% | 80% | 0.9 | 0.8 | 0.2 |
| 8241 | Shell | Advanced Walls - gas heat and electric cool base | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,073 | 10% | 207 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-13 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8242 | Shell | Advanced Walls - gas heat and electric cool base | Low Income | SF | LI | Retrofit | 2,073 | 10% | 207 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-14 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8243 | Shell | Advanced Walls - gas heat and electric cool base | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,073 | 10% | 207 | 0.23 | 20 | $2,470 | 100% | 40% | WALL-15 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8244 | Shell | Advanced Walls - gas heat and electric cool base | Low Income | MH | LI | Retrofit | 2,073 | 10% | 207 | 0.23 | 20 | $2,470 | 100% | 100% | WALL-16 | 19% | 80% | 0.9 | 0.8 | 0.3 |
| 8245 | Shell | Advanced Walls - gas heat and electric cool base | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 774 | 10% | 77 | 0.23 | 20 | $1,581 | 100% | 40% | WALL-17 | 15% | 80% | 0.9 | 0.8 | 0.2 |
| 8246 | Shell | Advanced Walls - gas heat and electric cool base | Low Income | MF | LI | Retrofit | 774 | 10% | 77 | 0.23 | 25 | $1,581 | 100% | 100% | WALL-18 | 15% | 80% | 0.9 | 0.8 | 0.3 |
| 9001 | Water Heating | Pipe Wrap | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 40% | WRAP-1 | 75% | 22% | 0.7 | 0.4 | 6.6 |
| 9002 | Water Heating | Pipe Wrap | Low Income | SF | LI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 100% | WRAP-2 | 75% | 22% | 0.7 | 0.5 | 6.6 |
| 9003 | Water Heating | Pipe Wrap | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 40% | WRAP-3 | 75% | 22% | 0.7 | 0.4 | 6.6 |
| 9004 | Water Heating | Pipe Wrap | Low Income | MH | LI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 100% | WRAP-4 | 75% | 22% | 0.7 | 0.5 | 6.6 |
| 9005 | Water Heating | Pipe Wrap | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 40% | WRAP-5 | 64% | 9% | 0.5 | 0.2 | 6.6 |
| 9006 | Water Heating | Pipe Wrap | Low Income | MF | LI | Retrofit | 2,942 | 3% | 89 | 0.01 | 15 | $9 | 100% | 100% | WRAP-6 | 64% | 9% | 0.5 | 0.3 | 6.6 |
| 9007 | Water Heating | Bathroom Aerator 1.0 gpm | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 40% | BATH-1 | 188% | 49% | 0.7 | 0.6 | 6.1 |
| 9008 | Water Heating | Bathroom Aerator 1.0 gpm | Low Income | SF | LI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 100% | BATH-2 | 188% | 49% | 0.7 | 0.6 | 6.1 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9009 | Water Heating | Bathroom Aerator 1.0 gpm | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 40% | BATH-3 | 188% | 49% | 0.7 | 0.6 | 6.1 |
| 9010 | Water Heating | Bathroom Aerator 1.0 gpm | Low Income | MH | LI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 100% | BATH-4 | 188% | 49% | 0.7 | 0.6 | 6.1 |
| 9011 | Water Heating | Bathroom Aerator 1.0 gpm | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 40% | BATH-5 | 128% | 38% | 0.6 | 0.5 | 6.1 |
| 9012 | Water Heating | Bathroom Aerator 1.0 gpm | Low Income | MF | LI | Retrofit | 2,942 | 1% | 35 | 0.01 | 10 | $3 | 100% | 100% | BATH-6 | 128% | 38% | 0.6 | 0.5 | 6.1 |
| 9013 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 40% | KITCH-1 | 75% | 49% | 0.7 | 0.6 | 24.3 |
| 9014 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Low Income | SF | LI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 100% | KITCH-2 | 75% | 49% | 0.7 | 0.6 | 24.3 |
| 9015 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 40% | KITCH-3 | 75% | 49% | 0.7 | 0.6 | 24.3 |
| 9016 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Low Income | MH | LI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 100% | KITCH-4 | 75% | 49% | 0.7 | 0.6 | 24.3 |
| 9017 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 40% | KITCH-5 | 64% | 38% | 0.6 | 0.5 | 24.2 |
| 9018 | Water Heating | Kitchen Flip Aerator 1.5 gpm | Low Income | MF | LI | Retrofit | 3,045 | 5% | 141 | 0.03 | 10 | $3 | 100% | 100% | KITCH-6 | 64% | 38% | 0.6 | 0.5 | 24.2 |
| 9019 | Water Heating | Low Flow Showerhead 1.5 gpm | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 40% | LFSH-1 | 150% | 61% | 0.7 | 0.7 | 14.7 |
| 9020 | Water Heating | Low Flow Showerhead 1.5 gpm | Low Income | SF | LI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 100% | LFSH-2 | 150% | 61% | 0.7 | 0.7 | 14.7 |
| 9021 | Water Heating | Low Flow Showerhead 1.5 gpm | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 40% | LFSH-3 | 150% | 61% | 0.7 | 0.7 | 14.7 |
| 9022 | Water Heating | Low Flow Showerhead 1.5 gpm | Low Income | MH | LI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 100% | LFSH-4 | 150% | 61% | 0.7 | 0.7 | 14.7 |
| 9023 | Water Heating | Low Flow Showerhead 1.5 gpm | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 40% | LFSH-5 | 113% | 51% | 0.7 | 0.6 | 14.7 |
| 9024 | Water Heating | Low Flow Showerhead 1.5 gpm | Low Income | MF | LI | Retrofit | 2,942 | 11% | 217 | 0.02 | 10 | $7 | 100% | 100% | LFSH-6 | 113% | 51% | 0.7 | 0.6 | 14.7 |
| 9025 | Water Heating | Thermostatic Restrictor Shower Valve | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 40% | TRSV-1 | 150% | 10% | 0.7 | 0.3 | 1.2 |
| 9026 | Water Heating | Thermostatic Restrictor Shower Valve | Low Income | SF | LI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 100% | TRSV-2 | 150% | 10% | 0.7 | 0.5 | 1.2 |
| 9027 | Water Heating | Thermostatic Restrictor Shower Valve | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 40% | TRSV-3 | 150% | 10% | 0.7 | 0.3 | 1.2 |
| 9028 | Water Heating | Thermostatic Restrictor Shower Valve | Low Income | MH | LI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 100% | TRSV-4 | 150% | 10% | 0.7 | 0.5 | 1.2 |
| 9029 | Water Heating | Thermostatic Restrictor Shower Valve | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 40% | TRSV-5 | 113% | 9% | 0.5 | 0.2 | 1.2 |
| 9030 | Water Heating | Thermostatic Restrictor Shower Valve | Low Income | MF | LI | Retrofit | 2,942 | 2% | 77 | 0.01 | 10 | $30 | 100% | 100% | TRSV-6 | 113% | 9% | 0.5 | 0.3 | 1.2 |
| 9031 | Water Heating | Heat Pump Water Heater-electric resistance heat | HVAC and Water Heating - Equipment | SF | NLI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 40% | HPWH-1 | 75% | 15% | 0.7 | 0.3 | 1.1 |
| 9032 | Water Heating | Heat Pump Water Heater-electric resistance heat | Low Income | SF | LI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 100% | HPWH-2 | 75% | 15% | 0.7 | 0.5 | 1.1 |
| 9033 | Water Heating | Heat Pump Water Heater-electric resistance heat | HVAC and Water Heating - Equipment | MH | NLI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 40% | HPWH-3 | 75% | 15% | 0.7 | 0.3 | 1.1 |
| 9034 | Water Heating | Heat Pump Water Heater-electric resistance heat | Low Income | MH | LI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 100% | HPWH-4 | 75% | 15% | 0.7 | 0.5 | 1.1 |
| 9035 | Water Heating | Heat Pump Water Heater-electric resistance heat | HVAC and Water Heating - Equipment | MF | NLI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 40% | HPWH-5 | 64% | 31% | 0.5 | 0.4 | 1.0 |
| 9036 | Water Heating | Heat Pump Water Heater-electric resistance heat | Low Income | MF | LI | MO | 2,942 | 68% | 2,011 | 0.10 | 13 | $1,199 | 100% | 100% | HPWH-6 | 64% | 31% | 0.5 | 0.4 | 1.0 |
| 9037 | Water Heating | Smart Water Heater - Tank Controls and Sensors | No program | SF | NLI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 40% | HPWH-1 | 75% | 15% | 0.7 | 0.3 | 2.0 |
| 9038 | Water Heating | Smart Water Heater - Tank Controls and Sensors | Low Income | SF | LI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 100% | HPWH-2 | 75% | 15% | 0.7 | 0.5 | 2.0 |
| 9039 | Water Heating | Smart Water Heater - Tank Controls and Sensors | No program | MH | NLI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 40% | HPWH-3 | 75% | 15% | 0.7 | 0.3 | 2.0 |
| 9040 | Water Heating | Smart Water Heater - Tank Controls and Sensors | Low Income | MH | LI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 100% | HPWH-4 | 75% | 15% | 0.7 | 0.5 | 2.0 |
| 9041 | Water Heating | Smart Water Heater - Tank Controls and Sensors | No program | MF | NLI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 40% | HPWH-5 | 64% | 31% | 0.5 | 0.4 | 2.0 |
| 9042 | Water Heating | Smart Water Heater - Tank Controls and Sensors | Low Income | MF | LI | MO | 2,942 | 15% | 441 | 0.02 | 13 | $120 | 100% | 100% | HPWH-6 | 64% | 31% | 0.5 | 0.4 | 2.0 |
| 9043 | Water Heating | Water Heater Wrap | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 40% | WRAP-1 | 75% | 12% | 0.7 | 0.3 | 1.1 |
| 9044 | Water Heating | Water Heater Wrap | Low Income | SF | LI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 100% | WRAP-2 | 75% | 12% | 0.7 | 0.5 | 1.1 |

**Appendix D: Residential Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Home Type:** Each measure is either a single-family (SF), manufactured (MH) or multifamily (MF) home. **Income Type:** Each measure is either low-income (LI), non-low-income (NLI) or not income-specific (N/A). **Replacement Type:** Market opportunity (MO), Retrofit, Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of homes with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Home Type | Income Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **9045** | Water Heating | Water Heater Wrap | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 40% | WRAP-3 | 75% | 12% | 0.7 | 0.3 | 1.1 |
| **9046** | Water Heating | Water Heater Wrap | Low Income | MH | LI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 100% | WRAP-4 | 75% | 12% | 0.7 | 0.5 | 1.1 |
| **9047** | Water Heating | Water Heater Wrap | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 40% | WRAP-5 | 64% | 4% | 0.5 | 0.2 | 1.1 |
| **9048** | Water Heating | Water Heater Wrap | Low Income | MF | LI | Retrofit | 2,942 | 3% | 80 | 0.01 | 5 | $20 | 100% | 100% | WRAP-6 | 64% | 4% | 0.5 | 0.3 | 1.1 |
| **9049** | Water Heating | Drain water Heat Recovery | No program | SF | NLI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 40% | DWHR-1 | 75% | 10% | 0.7 | 0.3 | 0.8 |
| **9050** | Water Heating | Drain water Heat Recovery | No program | SF | LI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 100% | DWHR-2 | 75% | 10% | 0.7 | 0.5 | 0.8 |
| **9051** | Water Heating | Drain water Heat Recovery | No program | MH | NLI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 40% | DWHR-3 | 75% | 10% | 0.7 | 0.3 | 0.8 |
| **9052** | Water Heating | Drain water Heat Recovery | No program | MH | LI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 100% | DWHR-4 | 75% | 10% | 0.7 | 0.5 | 0.8 |
| **9053** | Water Heating | Drain water Heat Recovery | No program | MF | NLI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 40% | DWHR-5 | 64% | 10% | 0.5 | 0.2 | 0.8 |
| **9054** | Water Heating | Drain water Heat Recovery | No program | MF | LI | Retrofit | 2,942 | 14% | 601 | 0.01 | 30 | $744 | 100% | 100% | DWHR-6 | 64% | 10% | 0.5 | 0.3 | 0.8 |
| **9055** | Water Heating | Shower Timer | Weatherization and WH non-equipment measures | SF | NLI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 40% | ST-1 | 150% | 1% | 0.7 | 0.3 | 0.3 |
| **9056** | Water Heating | Shower Timer | Low Income | SF | LI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 100% | ST-2 | 150% | 1% | 0.7 | 0.5 | 0.3 |
| **9057** | Water Heating | Shower Timer | Weatherization and WH non-equipment measures | MH | NLI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 40% | ST-3 | 150% | 1% | 0.7 | 0.2 | 0.3 |
| **9058** | Water Heating | Shower Timer | Low Income | MH | LI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 100% | ST-4 | 150% | 1% | 0.7 | 0.5 | 0.3 |
| **9059** | Water Heating | Shower Timer | Weatherization and WH non-equipment measures | MF | NLI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 40% | ST-5 | 113% | 7% | 0.5 | 0.2 | 0.3 |
| **9060** | Water Heating | Shower Timer | Low Income | MF | LI | Retrofit | 2,942 | 0% | 13 | 0.00 | 2 | $5 | 100% | 100% | ST-6 | 113% | 7% | 0.5 | 0.3 | 0.3 |
| **10001** | Electric Vehicle Charging | L2 ESVE | No program | SF | NLI | Retrofit | 2,733 | 31% | 836 | 0.00 | 10 | $900 | 100% | 40% | EV-1 | 2% | 20% | 0.5 | 0.3 | 0.4 |
| **10002** | Electric Vehicle Charging | L2 ESVE | No program | SF | LI | Retrofit | 2,734 | 31% | 836 | 0.00 | 10 | $900 | 100% | 100% | EV-2 | 2% | 20% | 0.5 | 0.4 | 0.4 |
| **10003** | Electric Vehicle Charging | L2 ESVE | No program | MH | NLI | Retrofit | 2,733 | 31% | 836 | 0.00 | 10 | $900 | 100% | 40% | EV-3 | 2% | 20% | 0.5 | 0.3 | 0.4 |
| **10004** | Electric Vehicle Charging | L2 ESVE | No program | MH | LI | Retrofit | 2,734 | 31% | 836 | 0.00 | 10 | $900 | 100% | 100% | EV-4 | 2% | 20% | 0.5 | 0.4 | 0.4 |
| **10005** | Electric Vehicle Charging | L2 ESVE | No program | MF | NLI | Retrofit | 2,736 | 31% | 836 | 0.00 | 10 | $900 | 100% | 40% | EV-5 | 2% | 20% | 0.5 | 0.3 | 0.4 |
| **10006** | Electric Vehicle Charging | L2 ESVE | No program | MF | LI | Retrofit | 2,737 | 31% | 836 | 0.00 | 10 | $900 | 100% | 100% | EV-6 | 2% | 20% | 0.5 | 0.4 | 0.4 |

# APPENDIX E: COMMERCIAL & INDUSTRIAL ENERGY EFFICIENCY DETAIL

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Assembly | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 2 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Assembly | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 3 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Assembly | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 4 | CompressedAir | AODD Pump Controls | Biz-Custom | Assembly | Retro | 103,919 | 35% | 36,372 | 4.50 | 4.34 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.2 |
| 5 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Assembly | Retro | 103,919 | 2% | 2,320 | 0.29 | 0.28 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 6 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Assembly | Retro | 1,480 | 50% | 740 | 0.09 | 0.09 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.0 |
| 7 | CompressedAir | Compressed Air - Custom | Biz-Custom | Assembly | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 8 | Cooking | Commercial Griddles | Biz-Prescriptive | Assembly | ROB | 15,825 | 12% | 1,910 | 0.47 | 0.20 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 9 | Cooking | Convection Ovens | Biz-Prescriptive | Assembly | ROB | 9,839 | 11% | 1,065 | 0.26 | 0.11 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 10 | Cooking | Combination Ovens | Biz-Prescriptive | Assembly | ROB | 23,958 | 38% | 9,058 | 2.21 | 0.96 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.3 |
| 11 | Cooking | Commercial Fryers | Biz-Prescriptive | Assembly | ROB | 18,955 | 17% | 3,274 | 0.80 | 0.35 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 12 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Assembly | ROB | 17,846 | 55% | 9,863 | 2.41 | 1.05 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 13 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Assembly | ROB | 13,697 | 68% | 9,314 | 2.28 | 0.99 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.7 |
| 14 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Assembly | ROB | 4,383 | 60% | 2,630 | 0.64 | 0.28 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.1 |
| 15 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Assembly | ROB | 39,306 | 44% | 17,369 | 2.35 | 2.71 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.3 |
| 16 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Assembly | ROB | 26,901 | 32% | 8,586 | 1.16 | 1.34 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.0 |
| 17 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Assembly | ROB | 606 | 15% | 89 | 0.04 | 0.00 | 15 | $153 | 100% | 40% | 1 | 21% | 10% | 0.8 | 0.3 | 0.4 |
| 18 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Assembly | ROB | 606 | 19% | 118 | 0.06 | 0.00 | 15 | $215 | 100% | 40% | 1 | 21% | 10% | 0.8 | 0.3 | 0.4 |
| 19 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Assembly | ROB | 606 | 31% | 188 | 0.09 | 0.00 | 15 | $399 | 100% | 40% | 1 | 21% | 10% | 0.8 | 0.3 | 0.4 |
| 20 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Assembly | ROB | 665 | 8% | 51 | 0.02 | 0.00 | 15 | $59 | 100% | 40% | 2 | 21% | 10% | 0.8 | 0.4 | 0.7 |
| 21 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Assembly | ROB | 665 | 12% | 80 | 0.04 | 0.00 | 15 | $97 | 100% | 40% | 2 | 21% | 10% | 0.8 | 0.4 | 0.6 |
| 22 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Assembly | ROB | 665 | 22% | 149 | 0.07 | 0.00 | 15 | $204 | 100% | 40% | 2 | 21% | 10% | 0.8 | 0.3 | 0.6 |
| 23 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Assembly | Retro | 732 | 7% | 51 | 0.02 | 0.00 | 3 | $5 | 100% | 40% | 3 | 42% | 50% | 0.8 | 0.6 | 1.9 |
| 24 | Cooling | Air Side Economizer | Biz-Custom | Assembly | Retro | 606 | 20% | 121 | 0.06 | 0.00 | 15 | $153 | 100% | 40% | 4 | 42% | 25% | 0.8 | 0.4 | 0.6 |
| 25 | Cooling | Advanced Rooftop Controls | Biz-Custom | Assembly | Retro | 6,773 | 56% | 3,779 | 1.82 | 0.04 | 15 | $2,950 | 100% | 40% | 5 | 42% | 20% | 0.8 | 0.5 | 1.0 |
| 26 | Cooling | HVAC Occupancy Controls | Biz-Custom | Assembly | Retro | 633 | 20% | 127 | 0.06 | 0.00 | 15 | $537 | 100% | 40% | 6 | 42% | 10% | 0.8 | 0.2 | 0.2 |
| 27 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Assembly | ROB | 627 | 13% | 78 | 0.04 | 0.00 | 15 | $115 | 100% | 40% | 7 | 23% | 10% | 0.8 | 0.3 | 0.5 |
| 28 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Assembly | ROB | 627 | 22% | 139 | 0.07 | 0.00 | 15 | $514 | 100% | 40% | 7 | 23% | 10% | 0.8 | 0.3 | 0.2 |
| 29 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Assembly | ROB | 627 | 33% | 209 | 0.10 | 0.00 | 15 | $631 | 100% | 40% | 7 | 23% | 10% | 0.8 | 0.3 | 0.3 |
| 30 | Cooling | Smart Thermostat | Biz-Prescriptive | Assembly | ROB | 2,510 | 14% | 355 | 0.17 | 0.00 | 11 | $175 | 100% | 40% | 8 | 23% | 10% | 0.8 | 0.5 | 1.2 |
| 31 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Assembly | ROB | 810 | 7% | 59 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 0% | 20% | 0.8 | 0.4 | 0.3 |
| 32 | Cooling | Air Cooled Chiller | Biz-Custom | Assembly | ROB | 641 | 9% | 58 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 31% | 10% | 0.8 | 0.3 | 0.5 |
| 33 | Cooling | Water Cooled Chiller | Biz-Custom | Assembly | ROB | 322 | 23% | 73 | 0.04 | 0.00 | 23 | $126 | 100% | 40% | 11 | 3% | 10% | 0.8 | 0.3 | 0.6 |
| 34 | Cooling | Window Film | Biz-Custom | Assembly | Retro | 6,000 | 4% | 264 | 0.13 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 35 | Cooling | Triple Pane Windows | Biz-Custom | Assembly | Retro | 6,000 | 6% | 360 | 0.17 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 36 | Cooling | Energy Recovery Ventilator | Biz-Custom | Assembly | Retro | 665 | 10% | 64 | 0.03 | 0.00 | 15 | $1,050 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.2 | 0.0 |
| 37 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Assembly | ROB | 2,068 | 3% | 70 | 0.01 | 0.02 | 15 | $135 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.4 |
| 38 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Assembly | ROB | 2,068 | 11% | 235 | 0.04 | 0.05 | 15 | $446 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.4 |
| 39 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Assembly | ROB | 2,068 | 17% | 345 | 0.06 | 0.08 | 15 | $446 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.6 |
| 40 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,318 | 6% | 140 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 2 | 18% | 10% | 0.8 | 0.5 | 1.1 |
| 41 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,318 | 11% | 260 | 0.04 | 0.06 | 15 | $171 | 100% | 40% | 2 | 18% | 10% | 0.8 | 0.5 | 1.1 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 42 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,398 | 6% | 154 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 3 | 18% | 10% | 0.8 | 0.5 | 1.2 |
| 43 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,398 | 12% | 282 | 0.05 | 0.06 | 15 | $182 | 100% | 40% | 3 | 18% | 10% | 0.8 | 0.5 | 1.2 |
| 44 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,506 | 7% | 169 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 4 | 18% | 10% | 0.8 | 0.5 | 1.3 |
| 45 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Assembly | ROB | 2,506 | 12% | 307 | 0.05 | 0.07 | 15 | $202 | 100% | 40% | 4 | 18% | 10% | 0.8 | 0.5 | 1.1 |
| 46 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Assembly | ROB | 1,604 | 3% | 54 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 0.5 |
| 47 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Assembly | ROB | 1,604 | 7% | 109 | 0.02 | 0.02 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 1.1 |
| 48 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Assembly | ROB | 2,523 | 7% | 175 | 0.03 | 0.04 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.5 | 0.9 |
| 49 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Assembly | ROB | 3,027 | 67% | 2,027 | 0.27 | 0.32 | 15 | $1,115 | 100% | 40% | 1 | 100% | 0% | 0.7 | 0.5 | 1.3 |
| 50 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Assembly | Retro | 3,027 | 2% | 61 | 0.01 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 0.9 |
| 51 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Assembly | ROB | 18,059 | 54% | 9,789 | 1.33 | 1.53 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 45.3 |
| 52 | HotWater | Faucet Aerator | Biz-Prescriptive | Assembly | Retro | 3,027 | 67% | 2,027 | 0.27 | 0.32 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 1.3 |
| 53 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Assembly | ROB | 1,868 | 20% | 380 | 0.05 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 54 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Assembly | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 55 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Assembly | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 56 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Assembly | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 57 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Assembly | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 58 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Assembly | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 59 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Assembly | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 60 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Assembly | Retro | 124 | 68% | 84 | 0.01 | 0.01 | 15 | $27 | 100% | 40% | 1 | 8% | 75% | 0.8 | 0.8 | 2.1 |
| 61 | Lighting_Int | LED interior directional | Biz-Prescriptive | Assembly | Retro | 89 | 74% | 66 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 0.8 |
| 62 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Assembly | Retro | 80 | 45% | 36 | 0.00 | 0.00 | 15 | $2 | 100% | 40% | 3 | 55% | 45% | 0.8 | 0.7 | 12.9 |
| 63 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Assembly | Retro | 181 | 50% | 91 | 0.01 | 0.01 | 15 | $70 | 100% | 40% | 3 | 55% | 45% | 0.8 | 0.6 | 0.9 |
| 64 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Assembly | Retro | 359 | 61% | 218 | 0.03 | 0.03 | 15 | $44 | 100% | 40% | 4 | 21% | 35% | 0.8 | 0.6 | 3.4 |
| 65 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Assembly | Retro | 1,687 | 68% | 1,147 | 0.15 | 0.15 | 15 | $330 | 100% | 40% | 5 | 14% | 35% | 0.8 | 0.6 | 2.4 |
| 66 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Assembly | Retro | 67 | 100% | 67 | 0.01 | 0.01 | 11 | $4 | 100% | 40% | 6 | 55% | 0% | 0.8 | 0.7 | 8.8 |
| 67 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Assembly | Retro | 390 | 30% | 117 | 0.01 | 0.02 | 10 | $58 | 100% | 40% | 7 | 91% | 20% | 0.8 | 0.6 | 1.0 |
| 68 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Assembly | Retro | 1 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 91% | 20% | 0.8 | 0.5 | 0.8 |
| 69 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Assembly | Retro | 305 | 30% | 91 | 0.01 | 0.01 | 15 | $54 | 100% | 40% | 7 | 91% | 20% | 0.8 | 0.5 | 1.1 |
| 70 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Assembly | Retro | 69 | 43% | 29 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 71 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Assembly | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 72 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Assembly | Retro | 9,932 | 50% | 4,966 | 0.61 | 0.59 | 20 | $1,180 | 100% | 40% | 2 | 12% | 10% | 0.8 | 0.6 | 3.5 |
| 73 | Misc | High Efficiency Hand Dryers | Biz-Custom | Assembly | Retro | 262 | 83% | 217 | 0.03 | 0.03 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.3 | 0.2 |
| 74 | Misc | Ozone Commercial Laundry | Biz-Custom | Assembly | Retro | 2,984 | 25% | 746 | 0.09 | 0.09 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 75 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Assembly | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 76 | Misc | Miscellaneous Custom | Biz-Custom | Assembly | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 35% | 10% | 0.8 | 0.3 | 0.3 |
| 77 | Motors | Cogged V-Belt | Biz-Custom | Assembly | Retro | 17,237 | 3% | 534 | 0.08 | 0.07 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.0 |
| 78 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Assembly | Retro | 3,805 | 34% | 1,290 | 0.19 | 0.17 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.3 |
| 79 | Motors | Power Drive Systems | Biz-Custom | Assembly | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.3 |
| 80 | Motors | Switch Reluctance Motors | Biz-Custom | Assembly | Retro | 33,406 | 31% | 10,222 | 1.50 | 1.32 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 13.3 |
| 81 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Assembly | Retro | 551 | 40% | 223 | 0.03 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 82 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Assembly | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 83 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Assembly | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 84 | Office_PC | Energy Star Server | Biz-Custom | Assembly | ROB | 1,621 | 23% | 368 | 0.05 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.2 |
| 85 | Office_PC | Server Virtualization | Biz-Custom | Assembly | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 86 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Assembly | Retro | 86,783 | 18% | 15,778 | 1.95 | 1.88 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 21.9 |
| 87 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Assembly | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 88 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Assembly | Retro | 764 | 47% | 358 | 0.04 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 89 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Assembly | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 90 | Refrigeration | Strip Curtains | Biz-Prescriptive | Assembly | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 11% | 30% | 0.7 | 0.6 | 0.0 |
| 91 | Refrigeration | Bare Suction Line | Biz-Custom | Assembly | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 92 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Assembly | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 7% | 25% | 0.7 | 0.4 | 0.4 |
| 93 | Refrigeration | Saturated Suction Controls | Biz-Custom | Assembly | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 94 | Refrigeration | Compressor Retrofit | Biz-Custom | Assembly | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 25% | 25% | 0.7 | 0.4 | 0.2 |
| 95 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Assembly | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 7% | 80% | 0.9 | 0.8 | 3.5 |
| 96 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Assembly | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 7% | 25% | 0.7 | 0.5 | 3.1 |
| 97 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Assembly | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 9% | 25% | 0.7 | 0.4 | 0.8 |
| 98 | Refrigeration | Refrigeration Economizer | Biz-Custom | Assembly | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 34% | 10% | 0.7 | 0.4 | 0.8 |
| 99 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Assembly | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 12% | 25% | 0.7 | 0.5 | 2.1 |
| 100 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Assembly | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 3% | 25% | 0.7 | 0.4 | 0.5 |
| 101 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Assembly | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 2% | 80% | 0.9 | 0.8 | 3.5 |
| 102 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Assembly | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 2% | 2% | 0.7 | 0.4 | 0.8 |
| 103 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Assembly | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.3 |
| 104 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Assembly | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.1 |
| 105 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Assembly | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 4% | 25% | 0.7 | 0.6 | 7.3 |
| 106 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Assembly | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 4% | 25% | 0.7 | 0.5 | 1.2 |
| 107 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Assembly | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.4 |
| 108 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Assembly | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.1 |
| 109 | Refrigeration | Refrigeration - Custom | Biz-Custom | Assembly | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 110 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Assembly | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 111 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Assembly | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 7% | 44% | 0.7 | 0.6 | 1.6 |
| 112 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Assembly | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 2% | 30% | 0.7 | 0.4 | 0.2 |
| 113 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Assembly | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 7% | 35% | 0.7 | 0.5 | 3.4 |
| 114 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Assembly | Retro | 1,698 | 20% | 340 | 0.05 | 0.05 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 1.7 |
| 115 | Ventilation | Demand Control Ventilation | Biz-Custom | Assembly | Retro | 2,166 | 43% | 940 | 0.14 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.9 |
| 116 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Assembly | Retro | 19,919 | 82% | 16,287 | 2.44 | 2.17 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.7 |
| 117 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Assembly | Retro | 21,909 | 83% | 18,277 | 2.74 | 2.43 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 3.0 |
| 118 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Assembly | Retro | 23,903 | 82% | 19,579 | 2.94 | 2.61 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.2 |
| 119 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Assembly | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 120 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Assembly | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 121 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Assembly | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.8 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 122 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Assembly | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 123 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Assembly | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 1.0 |
| 124 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Education | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.2 |
| 125 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Education | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 126 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Education | ROB | 1,583 | 21% | 329 | 0.03 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 127 | CompressedAir | AODD Pump Controls | Biz-Custom | Education | Retro | 103,919 | 35% | 36,372 | 3.45 | 4.08 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 14.9 |
| 128 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Education | Retro | 103,919 | 2% | 2,320 | 0.22 | 0.26 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 1.9 |
| 129 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Education | Retro | 1,480 | 50% | 740 | 0.07 | 0.08 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 9.7 |
| 130 | CompressedAir | Compressed Air - Custom | Biz-Custom | Education | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.2 |
| 131 | Cooking | Commercial Griddles | Biz-Prescriptive | Education | ROB | 15,825 | 12% | 1,910 | 0.02 | 0.07 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 132 | Cooking | Convection Ovens | Biz-Prescriptive | Education | ROB | 9,839 | 11% | 1,065 | 0.01 | 0.04 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 133 | Cooking | Combination Ovens | Biz-Prescriptive | Education | ROB | 23,958 | 38% | 9,058 | 0.10 | 0.35 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.2 |
| 134 | Cooking | Commercial Fryers | Biz-Prescriptive | Education | ROB | 18,955 | 17% | 3,274 | 0.04 | 0.13 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.2 |
| 135 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Education | ROB | 17,846 | 55% | 9,863 | 0.11 | 0.38 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.3 |
| 136 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Education | ROB | 13,697 | 68% | 9,314 | 0.10 | 0.36 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.3 |
| 137 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Education | ROB | 4,383 | 60% | 2,630 | 0.03 | 0.10 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.0 |
| 138 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Education | ROB | 39,306 | 44% | 17,369 | 1.78 | 2.76 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 17.9 |
| 139 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Education | ROB | 26,901 | 32% | 8,586 | 0.88 | 1.36 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 5.9 |
| 140 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Education | ROB | 509 | 15% | 75 | 0.04 | 0.00 | 15 | $153 | 100% | 40% | 1 | 24% | 10% | 0.8 | 0.3 | 0.4 |
| 141 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Education | ROB | 509 | 19% | 99 | 0.05 | 0.00 | 15 | $215 | 100% | 40% | 1 | 24% | 10% | 0.8 | 0.3 | 0.4 |
| 142 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Education | ROB | 509 | 31% | 158 | 0.08 | 0.00 | 15 | $399 | 100% | 40% | 1 | 24% | 10% | 0.8 | 0.3 | 0.3 |
| 143 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Education | ROB | 559 | 8% | 43 | 0.02 | 0.00 | 15 | $59 | 100% | 40% | 2 | 24% | 10% | 0.8 | 0.3 | 0.6 |
| 144 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Education | ROB | 559 | 12% | 67 | 0.04 | 0.00 | 15 | $97 | 100% | 40% | 2 | 24% | 10% | 0.8 | 0.3 | 0.5 |
| 145 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Education | ROB | 559 | 22% | 125 | 0.07 | 0.00 | 15 | $204 | 100% | 40% | 2 | 24% | 10% | 0.8 | 0.3 | 0.5 |
| 146 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Education | Retro | 615 | 7% | 43 | 0.02 | 0.00 | 3 | $5 | 100% | 40% | 3 | 49% | 50% | 0.8 | 0.6 | 1.6 |
| 147 | Cooling | Air Side Economizer | Biz-Custom | Education | Retro | 509 | 20% | 102 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 4 | 49% | 25% | 0.8 | 0.4 | 0.5 |
| 148 | Cooling | Advanced Rooftop Controls | Biz-Custom | Education | Retro | 6,304 | 56% | 3,518 | 1.86 | 0.02 | 15 | $2,950 | 100% | 40% | 5 | 49% | 20% | 0.8 | 0.4 | 0.9 |
| 149 | Cooling | HVAC Occupancy Controls | Biz-Custom | Education | Retro | 532 | 20% | 106 | 0.06 | 0.00 | 15 | $537 | 100% | 40% | 6 | 49% | 10% | 0.8 | 0.2 | 0.2 |
| 150 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Education | ROB | 527 | 13% | 66 | 0.03 | 0.00 | 15 | $115 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 151 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Education | ROB | 527 | 22% | 117 | 0.06 | 0.00 | 15 | $514 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.2 | 0.2 |
| 152 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Education | ROB | 527 | 33% | 176 | 0.09 | 0.00 | 15 | $631 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.2 |
| 153 | Cooling | Smart Thermostat | Biz-Prescriptive | Education | ROB | 2,109 | 14% | 299 | 0.16 | 0.00 | 11 | $175 | 100% | 40% | 8 | 0% | 10% | 0.8 | 0.5 | 1.0 |
| 154 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Education | ROB | 680 | 7% | 49 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 0% | 20% | 0.8 | 0.4 | 0.3 |
| 155 | Cooling | Air Cooled Chiller | Biz-Custom | Education | ROB | 539 | 9% | 49 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 46% | 10% | 0.8 | 0.3 | 0.4 |
| 156 | Cooling | Water Cooled Chiller | Biz-Custom | Education | ROB | 271 | 23% | 62 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 11 | 5% | 10% | 0.8 | 0.3 | 0.5 |
| 157 | Cooling | Window Film | Biz-Custom | Education | Retro | 6,000 | 4% | 264 | 0.14 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 158 | Cooling | Triple Pane Windows | Biz-Custom | Education | Retro | 6,000 | 6% | 360 | 0.19 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 159 | Cooling | Energy Recovery Ventilator | Biz-Custom | Education | Retro | 559 | 18% | 103 | 0.05 | 0.00 | 15 | $1,049 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.2 | 0.1 |
| 160 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Education | ROB | 2,383 | 3% | 73 | 0.01 | 0.02 | 15 | $135 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 161 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Education | ROB | 2,383 | 11% | 257 | 0.05 | 0.07 | 15 | $446 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 162 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Education | ROB | 2,383 | 15% | 368 | 0.07 | 0.09 | 15 | $520 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.5 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 163 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,682 | 6% | 158 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 2 | 28% | 10% | 0.8 | 0.5 | 1.2 |
| 164 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,682 | 11% | 296 | 0.05 | 0.08 | 15 | $171 | 100% | 40% | 2 | 28% | 10% | 0.8 | 0.5 | 1.3 |
| 165 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,772 | 6% | 173 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 3 | 27% | 10% | 0.8 | 0.5 | 1.3 |
| 166 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,772 | 11% | 318 | 0.06 | 0.08 | 15 | $182 | 100% | 40% | 3 | 27% | 10% | 0.8 | 0.5 | 1.3 |
| 167 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,886 | 7% | 188 | 0.03 | 0.05 | 15 | $100 | 100% | 40% | 4 | 27% | 10% | 0.8 | 0.5 | 1.4 |
| 168 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Education | ROB | 2,886 | 12% | 345 | 0.06 | 0.09 | 15 | $202 | 100% | 40% | 4 | 27% | 10% | 0.8 | 0.5 | 1.3 |
| 169 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Education | ROB | 1,810 | 3% | 58 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 0.6 |
| 170 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Education | ROB | 1,810 | 6% | 104 | 0.02 | 0.03 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 1.1 |
| 171 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Education | ROB | 2,912 | 5% | 158 | 0.03 | 0.04 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.5 | 0.9 |
| 172 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Education | ROB | 5,042 | 67% | 3,377 | 0.35 | 0.54 | 15 | $1,115 | 100% | 40% | 1 | 100% | 23% | 0.7 | 0.5 | 2.1 |
| 173 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Education | Retro | 5,042 | 2% | 101 | 0.01 | 0.02 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.4 |
| 174 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Education | ROB | 18,059 | 54% | 9,789 | 1.00 | 1.56 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 44.4 |
| 175 | HotWater | Faucet Aerator | Biz-Prescriptive | Education | Retro | 5,042 | 67% | 3,377 | 0.35 | 0.54 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 2.1 |
| 176 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Education | ROB | 1,868 | 20% | 380 | 0.04 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 177 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Education | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 178 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Education | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 179 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Education | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 180 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Education | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 181 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Education | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.22 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 182 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Education | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 183 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Education | Retro | 180 | 68% | 121 | 0.01 | 0.01 | 15 | $27 | 100% | 40% | 1 | 3% | 75% | 0.8 | 0.8 | 3.0 |
| 184 | Lighting_Int | LED interior directional | Biz-Prescriptive | Education | Retro | 129 | 74% | 95 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.1 |
| 185 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Education | Retro | 116 | 45% | 52 | 0.00 | 0.01 | 15 | $2 | 100% | 40% | 3 | 84% | 45% | 0.8 | 0.7 | 18.1 |
| 186 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Education | Retro | 262 | 50% | 131 | 0.01 | 0.02 | 15 | $70 | 100% | 40% | 3 | 84% | 45% | 0.8 | 0.6 | 1.2 |
| 187 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Education | Retro | 520 | 61% | 316 | 0.03 | 0.04 | 15 | $44 | 100% | 40% | 4 | 7% | 35% | 0.8 | 0.7 | 4.7 |
| 188 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Education | Retro | 2,440 | 68% | 1,660 | 0.16 | 0.20 | 15 | $330 | 100% | 40% | 5 | 5% | 35% | 0.8 | 0.6 | 3.3 |
| 189 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Education | Retro | 97 | 100% | 97 | 0.01 | 0.01 | 11 | $4 | 100% | 40% | 6 | 84% | 0% | 0.8 | 0.7 | 12.4 |
| 190 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Education | Retro | 564 | 30% | 169 | 0.02 | 0.02 | 10 | $58 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.6 | 1.4 |
| 191 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Education | Retro | 2 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.5 | 1.1 |
| 192 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Education | Retro | 440 | 30% | 132 | 0.01 | 0.02 | 15 | $78 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.5 | 1.1 |
| 193 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Education | Retro | 66 | 43% | 28 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 194 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Education | Retro | 385 | 61% | 237 | 0.02 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 195 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Education | Retro | 9,932 | 50% | 4,966 | 0.47 | 0.56 | 20 | $1,180 | 100% | 40% | 2 | 6% | 10% | 0.8 | 0.6 | 3.4 |
| 196 | Misc | High Efficiency Hand Dryers | Biz-Custom | Education | Retro | 2,093 | 83% | 1,737 | 0.16 | 0.20 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.6 | 1.7 |
| 197 | Misc | Ozone Commercial Laundry | Biz-Custom | Education | Retro | 2,984 | 25% | 746 | 0.07 | 0.08 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 198 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Education | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 0.9 |
| 199 | Misc | Miscellaneous Custom | Biz-Custom | Education | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 10% | 10% | 0.8 | 0.3 | 0.3 |
| 200 | Motors | Cogged V-Belt | Biz-Custom | Education | Retro | 17,237 | 3% | 534 | 0.11 | 0.05 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.0 |
| 201 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Education | Retro | 3,805 | 34% | 1,290 | 0.27 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 202 | Motors | Power Drive Systems | Biz-Custom | Education | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |
| 203 | Motors | Switch Reluctance Motors | Biz-Custom | Education | Retro | 33,406 | 31% | 10,222 | 2.15 | 1.01 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 13.5 |
| 204 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Education | Retro | 551 | 40% | 223 | 0.02 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| 205 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Education | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 206 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Education | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 0.9 |
| 207 | Office_PC | Energy Star Server | Biz-Custom | Education | ROB | 1,621 | 23% | 368 | 0.03 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.2 |
| 208 | Office_PC | Server Virtualization | Biz-Custom | Education | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 209 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Education | Retro | 86,783 | 18% | 15,778 | 1.50 | 1.77 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 21.4 |
| 210 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Education | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 211 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Education | Retro | 764 | 47% | 358 | 0.03 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.8 |
| 212 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Education | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.6 |
| 213 | Refrigeration | Strip Curtains | Biz-Prescriptive | Education | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 11% | 30% | 0.7 | 0.6 | 0.0 |
| 214 | Refrigeration | Bare Suction Line | Biz-Custom | Education | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 215 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Education | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 7% | 25% | 0.7 | 0.4 | 0.4 |
| 216 | Refrigeration | Saturated Suction Controls | Biz-Custom | Education | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 217 | Refrigeration | Compressor Retrofit | Biz-Custom | Education | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 25% | 25% | 0.7 | 0.4 | 0.2 |
| 218 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Education | Retro | 2,884 | 55% | 1,586 | 0.23 | 0.17 | 15 | $305 | 100% | 40% | 6 | 7% | 80% | 0.9 | 0.8 | 3.5 |
| 219 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Education | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 7% | 25% | 0.7 | 0.5 | 3.1 |
| 220 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Education | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 9% | 25% | 0.7 | 0.4 | 0.8 |
| 221 | Refrigeration | Refrigeration Economizer | Biz-Custom | Education | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 35% | 10% | 0.7 | 0.4 | 0.8 |
| 222 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Education | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 12% | 75% | 0.8 | 0.8 | 2.1 |
| 223 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Education | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 3% | 25% | 0.7 | 0.4 | 0.5 |
| 224 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Education | Retro | 2,884 | 55% | 1,586 | 0.23 | 0.17 | 15 | $305 | 100% | 40% | 12 | 2% | 80% | 0.9 | 0.8 | 3.5 |
| 225 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Education | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 2% | 2% | 0.7 | 0.4 | 0.8 |
| 226 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Education | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 12% | 54% | 0.7 | 0.6 | 0.3 |
| 227 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Education | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 12% | 54% | 0.7 | 0.6 | 0.1 |
| 228 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Education | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 4% | 75% | 0.8 | 0.8 | 7.3 |
| 229 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Education | Retro | 2,922 | 50% | 1,453 | 0.21 | 0.16 | 12 | $686 | 100% | 40% | 16 | 4% | 25% | 0.7 | 0.5 | 1.2 |
| 230 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Education | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.4 |
| 231 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Education | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.1 |
| 232 | Refrigeration | Refrigeration - Custom | Biz-Custom | Education | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 233 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Education | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 234 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Education | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 4% | 44% | 0.7 | 0.6 | 1.6 |
| 235 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Education | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 3% | 30% | 0.7 | 0.4 | 0.2 |
| 236 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Education | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 7% | 35% | 0.7 | 0.5 | 3.4 |
| 237 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Education | Retro | 2,223 | 20% | 445 | 0.07 | 0.06 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.2 |
| 238 | Ventilation | Demand Control Ventilation | Biz-Custom | Education | Retro | 2,166 | 43% | 940 | 0.15 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.9 |
| 239 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Education | Retro | 19,919 | 82% | 16,287 | 2.54 | 2.30 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.7 |
| 240 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Education | Retro | 21,909 | 83% | 18,277 | 2.86 | 2.58 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 3.0 |
| 241 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Education | Retro | 23,903 | 82% | 19,579 | 3.06 | 2.76 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.2 |
| 242 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Education | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.8 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 243 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Education | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 244 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Education | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.9 |
| 245 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Education | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.5 |
| 246 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Education | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 1.0 |
| 247 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Food Sales | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.4 |
| 248 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Food Sales | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 249 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Food Sales | ROB | 1,583 | 21% | 329 | 0.05 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.6 |
| 250 | CompressedAir | AODD Pump Controls | Biz-Custom | Food Sales | Retro | 103,919 | 35% | 36,372 | 5.62 | 4.17 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.5 |
| 251 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Food Sales | Retro | 103,919 | 2% | 2,320 | 0.36 | 0.27 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 252 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Food Sales | Retro | 1,480 | 50% | 740 | 0.11 | 0.08 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.2 |
| 253 | CompressedAir | Compressed Air - Custom | Biz-Custom | Food Sales | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 254 | Cooking | Commercial Griddles | Biz-Prescriptive | Food Sales | ROB | 15,825 | 12% | 1,910 | 0.39 | 0.24 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 255 | Cooking | Convection Ovens | Biz-Prescriptive | Food Sales | ROB | 9,839 | 11% | 1,065 | 0.22 | 0.13 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 256 | Cooking | Combination Ovens | Biz-Prescriptive | Food Sales | ROB | 23,958 | 38% | 9,058 | 1.84 | 1.14 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.2 |
| 257 | Cooking | Commercial Fryers | Biz-Prescriptive | Food Sales | ROB | 18,955 | 17% | 3,274 | 0.66 | 0.41 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 258 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Food Sales | ROB | 17,846 | 55% | 9,863 | 2.00 | 1.25 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 259 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Food Sales | ROB | 13,697 | 68% | 9,314 | 1.89 | 1.18 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.6 |
| 260 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Food Sales | ROB | 4,383 | 60% | 2,630 | 0.53 | 0.33 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.0 |
| 261 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Food Sales | ROB | 39,306 | 44% | 17,369 | 2.34 | 2.62 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.2 |
| 262 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Food Sales | ROB | 26,901 | 32% | 8,586 | 1.16 | 1.29 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.0 |
| 263 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Food Sales | ROB | 789 | 15% | 116 | 0.08 | 0.00 | 15 | $153 | 100% | 40% | 1 | 20% | 10% | 0.8 | 0.3 | 0.6 |
| 264 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Food Sales | ROB | 789 | 19% | 153 | 0.10 | 0.00 | 15 | $215 | 100% | 40% | 1 | 20% | 10% | 0.8 | 0.3 | 0.6 |
| 265 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Food Sales | ROB | 789 | 31% | 244 | 0.16 | 0.00 | 15 | $399 | 100% | 40% | 1 | 20% | 10% | 0.8 | 0.3 | 0.5 |
| 266 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Food Sales | ROB | 866 | 8% | 67 | 0.04 | 0.00 | 15 | $59 | 100% | 40% | 2 | 20% | 10% | 0.8 | 0.4 | 1.0 |
| 267 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Food Sales | ROB | 866 | 12% | 104 | 0.07 | 0.00 | 15 | $97 | 100% | 40% | 2 | 20% | 10% | 0.8 | 0.4 | 0.9 |
| 268 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Food Sales | ROB | 866 | 22% | 194 | 0.13 | 0.00 | 15 | $204 | 100% | 40% | 2 | 20% | 10% | 0.8 | 0.4 | 0.8 |
| 269 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Food Sales | Retro | 953 | 7% | 67 | 0.04 | 0.00 | 3 | $5 | 100% | 40% | 3 | 40% | 50% | 0.8 | 0.6 | 2.7 |
| 270 | Cooling | Air Side Economizer | Biz-Custom | Food Sales | Retro | 789 | 20% | 158 | 0.10 | 0.00 | 15 | $153 | 100% | 40% | 4 | 40% | 25% | 0.8 | 0.4 | 0.9 |
| 271 | Cooling | Advanced Rooftop Controls | Biz-Custom | Food Sales | Retro | 6,900 | 56% | 3,850 | 2.52 | 0.00 | 15 | $2,950 | 100% | 40% | 5 | 40% | 20% | 0.8 | 0.5 | 1.1 |
| 272 | Cooling | HVAC Occupancy Controls | Biz-Custom | Food Sales | Retro | 824 | 20% | 165 | 0.11 | 0.00 | 15 | $537 | 100% | 40% | 6 | 40% | 10% | 0.8 | 0.3 | 0.3 |
| 273 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 817 | 13% | 102 | 0.07 | 0.00 | 15 | $115 | 100% | 40% | 7 | 20% | 10% | 0.8 | 0.4 | 0.8 |
| 274 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 817 | 22% | 182 | 0.12 | 0.00 | 15 | $514 | 100% | 40% | 7 | 20% | 10% | 0.8 | 0.3 | 0.3 |
| 275 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 817 | 33% | 272 | 0.18 | 0.00 | 15 | $631 | 100% | 40% | 7 | 20% | 10% | 0.8 | 0.3 | 0.4 |
| 276 | Cooling | Smart Thermostat | Biz-Prescriptive | Food Sales | ROB | 3,267 | 14% | 463 | 0.30 | 0.00 | 11 | $175 | 100% | 40% | 8 | 20% | 10% | 0.8 | 0.6 | 1.7 |
| 277 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Food Sales | ROB | 1,054 | 7% | 77 | 0.05 | 0.00 | 8 | $84 | 100% | 40% | 9 | 40% | 20% | 0.8 | 0.4 | 0.5 |
| 278 | Cooling | Air Cooled Chiller | Biz-Custom | Food Sales | ROB | 835 | 9% | 75 | 0.05 | 0.00 | 23 | $126 | 100% | 40% | 10 | 0% | 10% | 0.8 | 0.3 | 0.7 |
| 279 | Cooling | Water Cooled Chiller | Biz-Custom | Food Sales | ROB | 419 | 23% | 95 | 0.06 | 0.00 | 23 | $126 | 100% | 40% | 11 | 0% | 10% | 0.8 | 0.3 | 0.9 |
| 280 | Cooling | Window Film | Biz-Custom | Food Sales | Retro | 6,000 | 4% | 264 | 0.17 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.6 |
| 281 | Cooling | Triple Pane Windows | Biz-Custom | Food Sales | Retro | 6,000 | 6% | 360 | 0.24 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.7 |
| 282 | Cooling | Energy Recovery Ventilator | Biz-Custom | Food Sales | Retro | 866 | 20% | 176 | 0.12 | 0.00 | 15 | $1,048 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.2 | 0.1 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 283 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 1,996 | 4% | 75 | 0.02 | 0.02 | 15 | $135 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.3 | 0.4 |
| 284 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 1,996 | 12% | 242 | 0.05 | 0.06 | 15 | $446 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.3 | 0.4 |
| 285 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Food Sales | ROB | 1,996 | 18% | 366 | 0.08 | 0.10 | 15 | $520 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.3 | 0.6 |
| 286 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,227 | 6% | 138 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.1 |
| 287 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,227 | 11% | 256 | 0.06 | 0.07 | 15 | $171 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.2 |
| 288 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,306 | 7% | 154 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 3 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 289 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,306 | 12% | 278 | 0.06 | 0.07 | 15 | $182 | 100% | 40% | 3 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 290 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,421 | 7% | 170 | 0.04 | 0.05 | 15 | $100 | 100% | 40% | 4 | 16% | 10% | 0.8 | 0.5 | 1.4 |
| 291 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Food Sales | ROB | 2,421 | 13% | 307 | 0.07 | 0.08 | 15 | $202 | 100% | 40% | 4 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 292 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Food Sales | ROB | 1,590 | 4% | 57 | 0.01 | 0.02 | 25 | $108 | 100% | 40% | 5 | 8% | 20% | 0.8 | 0.4 | 0.6 |
| 293 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Food Sales | ROB | 1,590 | 8% | 128 | 0.03 | 0.03 | 25 | $108 | 100% | 40% | 5 | 8% | 20% | 0.8 | 0.4 | 1.4 |
| 294 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Food Sales | ROB | 2,431 | 9% | 215 | 0.05 | 0.06 | 8 | $84 | 100% | 40% | 6 | 10% | 20% | 0.8 | 0.6 | 1.2 |
| 295 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Food Sales | ROB | 4,687 | 67% | 3,139 | 0.42 | 0.47 | 15 | $1,115 | 100% | 40% | 1 | 100% | 0% | 0.7 | 0.5 | 2.0 |
| 296 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Food Sales | Retro | 4,687 | 2% | 94 | 0.01 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.3 |
| 297 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Food Sales | ROB | 18,059 | 54% | 9,789 | 1.32 | 1.48 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 45.1 |
| 298 | HotWater | Faucet Aerator | Biz-Prescriptive | Food Sales | Retro | 4,687 | 67% | 3,139 | 0.42 | 0.47 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 2.0 |
| 299 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Food Sales | ROB | 1,868 | 20% | 380 | 0.05 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 300 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Food Sales | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 301 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Food Sales | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 302 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Food Sales | Retro | 1,589 | 60% | 959 | 0.00 | 0.12 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 303 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Food Sales | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.15 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 304 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Food Sales | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.25 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 305 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Food Sales | Retro | 1,589 | 60% | 959 | 0.00 | 0.12 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 306 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Food Sales | Retro | 306 | 68% | 206 | 0.03 | 0.02 | 9 | $27 | 100% | 40% | 1 | 2% | 75% | 0.8 | 0.8 | 3.4 |
| 307 | Lighting_Int | LED interior directional | Biz-Prescriptive | Food Sales | Retro | 220 | 74% | 162 | 0.02 | 0.02 | 9 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.2 |
| 308 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Food Sales | Retro | 197 | 45% | 88 | 0.01 | 0.01 | 9 | $2 | 100% | 40% | 3 | 85% | 45% | 0.8 | 0.7 | 20.7 |
| 309 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Food Sales | Retro | 445 | 50% | 223 | 0.03 | 0.03 | 9 | $70 | 100% | 40% | 3 | 85% | 45% | 0.8 | 0.6 | 1.4 |
| 310 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Food Sales | Retro | 883 | 61% | 537 | 0.07 | 0.06 | 9 | $44 | 100% | 40% | 4 | 6% | 35% | 0.8 | 0.7 | 5.4 |
| 311 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Food Sales | Retro | 4,147 | 68% | 2,821 | 0.34 | 0.33 | 9 | $330 | 100% | 40% | 5 | 4% | 35% | 0.8 | 0.7 | 3.8 |
| 312 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Food Sales | Retro | 164 | 100% | 164 | 0.02 | 0.02 | 11 | $4 | 100% | 40% | 6 | 85% | 0% | 0.8 | 0.7 | 21.3 |
| 313 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Food Sales | Retro | 959 | 30% | 288 | 0.03 | 0.03 | 10 | $58 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.6 | 2.4 |
| 314 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Food Sales | Retro | 4 | 49% | 2 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.6 | 1.9 |
| 315 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Food Sales | Retro | 749 | 30% | 225 | 0.03 | 0.03 | 15 | $133 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.5 | 1.1 |
| 316 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Food Sales | Retro | 64 | 43% | 28 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 317 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Food Sales | Retro | 385 | 61% | 237 | 0.05 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 318 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Food Sales | Retro | 9,932 | 50% | 4,966 | 1.01 | 0.63 | 20 | $1,180 | 100% | 40% | 2 | 1% | 10% | 0.8 | 0.6 | 3.7 |
| 319 | Misc | High Efficiency Hand Dryers | Biz-Custom | Food Sales | Retro | 3,819 | 83% | 3,170 | 0.64 | 0.40 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.7 | 3.3 |
| 320 | Misc | Ozone Commercial Laundry | Biz-Custom | Food Sales | Retro | 2,984 | 25% | 746 | 0.15 | 0.09 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 321 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Food Sales | ROB | 3,096 | 3% | 85 | 0.02 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 322 | Misc | Miscellaneous Custom | Biz-Custom | Food Sales | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 29% | 10% | 0.8 | 0.3 | 0.4 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 323 | Motors | Cogged V-Belt | Biz-Custom | Food Sales | Retro | 19,471 | 3% | 604 | 0.00 | 0.14 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.1 |
| 324 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Food Sales | Retro | 3,805 | 34% | 1,290 | 0.00 | 0.29 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 325 | Motors | Power Drive Systems | Biz-Custom | Food Sales | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 326 | Motors | Switch Reluctance Motors | Biz-Custom | Food Sales | Retro | 37,735 | 31% | 11,547 | 0.00 | 2.63 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 14.8 |
| 327 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Food Sales | Retro | 551 | 40% | 223 | 0.05 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| 328 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Food Sales | Retro | 1,086 | 10% | 109 | 0.02 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 329 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Food Sales | Retro | 1,126 | 15% | 169 | 0.03 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 330 | Office_PC | Energy Star Server | Biz-Custom | Food Sales | ROB | 1,621 | 23% | 368 | 0.07 | 0.05 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.3 |
| 331 | Office_PC | Server Virtualization | Biz-Custom | Food Sales | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.1 |
| 332 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Food Sales | Retro | 86,783 | 18% | 15,778 | 3.20 | 1.99 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 23.2 |
| 333 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Food Sales | ROB | 541 | 30% | 162 | 0.03 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.8 |
| 334 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Food Sales | Retro | 764 | 47% | 358 | 0.07 | 0.05 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 3.1 |
| 335 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Food Sales | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.8 |
| 336 | Refrigeration | Strip Curtains | Biz-Prescriptive | Food Sales | Retro | 412 | 50% | 206 | 0.03 | 0.02 | 4 | $10 | 100% | 40% | 1 | 16% | 30% | 0.7 | 0.6 | 4.4 |
| 337 | Refrigeration | Bare Suction Line | Biz-Custom | Food Sales | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 1% | 50% | 0.7 | 0.6 | 3.5 |
| 338 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Food Sales | Retro | 1,112 | 25% | 278 | 0.03 | 0.03 | 15 | $431 | 100% | 40% | 3 | 11% | 25% | 0.7 | 0.4 | 0.4 |
| 339 | Refrigeration | Saturated Suction Controls | Biz-Custom | Food Sales | Retro | 831 | 50% | 416 | 0.05 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 340 | Refrigeration | Compressor Retrofit | Biz-Custom | Food Sales | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 37% | 25% | 0.7 | 0.4 | 0.2 |
| 341 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Food Sales | Retro | 2,884 | 55% | 1,586 | 0.19 | 0.19 | 15 | $305 | 100% | 40% | 6 | 10% | 80% | 0.9 | 0.8 | 3.5 |
| 342 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Food Sales | Retro | 2,236 | 32% | 716 | 0.09 | 0.08 | 15 | $155 | 100% | 40% | 7 | 10% | 25% | 0.7 | 0.5 | 3.1 |
| 343 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Food Sales | Retro | 2,960 | 50% | 1,480 | 0.18 | 0.17 | 15 | $1,170 | 100% | 40% | 8 | 14% | 25% | 0.7 | 0.4 | 0.8 |
| 344 | Refrigeration | Refrigeration Economizer | Biz-Custom | Food Sales | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 52% | 10% | 0.7 | 0.4 | 0.8 |
| 345 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Food Sales | Retro | 579 | 59% | 338 | 0.04 | 0.04 | 10 | $80 | 100% | 40% | 10 | 8% | 75% | 0.8 | 0.8 | 2.1 |
| 346 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Food Sales | Retro | 1,584 | 36% | 578 | 0.07 | 0.07 | 12 | $686 | 100% | 40% | 11 | 2% | 25% | 0.7 | 0.4 | 0.5 |
| 347 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Food Sales | Retro | 2,884 | 55% | 1,586 | 0.19 | 0.19 | 15 | $305 | 100% | 40% | 12 | 1% | 80% | 0.9 | 0.8 | 3.5 |
| 348 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Food Sales | Retro | 641 | 38% | 242 | 0.03 | 0.03 | 10 | $102 | 100% | 40% | 13 | 1% | 2% | 0.7 | 0.5 | 1.1 |
| 349 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Food Sales | ROB | 2,140 | 29% | 629 | 0.08 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 8% | 54% | 0.7 | 0.6 | 0.3 |
| 350 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Food Sales | ROB | 1,410 | 20% | 281 | 0.03 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 8% | 54% | 0.7 | 0.6 | 0.1 |
| 351 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Food Sales | Retro | 2,016 | 68% | 1,361 | 0.17 | 0.16 | 10 | $91 | 100% | 40% | 15 | 3% | 75% | 0.8 | 0.8 | 7.2 |
| 352 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Food Sales | Retro | 2,922 | 50% | 1,453 | 0.18 | 0.17 | 12 | $686 | 100% | 40% | 16 | 3% | 25% | 0.7 | 0.5 | 1.2 |
| 353 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Food Sales | ROB | 6,374 | 20% | 1,275 | 0.16 | 0.15 | 12 | $1,651 | 100% | 40% | 17 | 3% | 54% | 0.7 | 0.6 | 0.4 |
| 354 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Food Sales | ROB | 4,522 | 7% | 305 | 0.04 | 0.04 | 12 | $1,521 | 100% | 40% | 17 | 3% | 54% | 0.7 | 0.6 | 0.1 |
| 355 | Refrigeration | Refrigeration - Custom | Biz-Custom | Food Sales | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 356 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Food Sales | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 357 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Food Sales | ROB | 6,993 | 10% | 721 | 0.09 | 0.09 | 10 | $222 | 100% | 40% | 20 | 0% | 44% | 0.7 | 0.6 | 1.6 |
| 358 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Food Sales | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 0% | 30% | 0.7 | 0.4 | 0.2 |
| 359 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Food Sales | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 5% | 35% | 0.7 | 0.5 | 3.4 |
| 360 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Food Sales | Retro | 2,658 | 20% | 532 | 0.08 | 0.08 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.8 |
| 361 | Ventilation | Demand Control Ventilation | Biz-Custom | Food Sales | Retro | 2,166 | 43% | 940 | 0.14 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.9 |
| 362 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Food Sales | Retro | 19,919 | 82% | 16,287 | 2.37 | 2.30 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.7 |
| 363 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Food Sales | Retro | 21,909 | 83% | 18,277 | 2.67 | 2.58 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 3.0 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 364 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Food Sales | Retro | 23,903 | 82% | 19,579 | 2.85 | 2.76 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.2 |
| 365 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Food Sales | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 366 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Food Sales | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 367 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Food Sales | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.7 |
| 368 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Food Sales | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 369 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Food Sales | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 0.9 |
| 370 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Food Service | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 371 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Food Service | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 372 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Food Service | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 373 | CompressedAir | AODD Pump Controls | Biz-Custom | Food Service | Retro | 103,919 | 35% | 36,372 | 4.72 | 4.02 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.0 |
| 374 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Food Service | Retro | 103,919 | 2% | 2,320 | 0.30 | 0.26 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 1.9 |
| 375 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Food Service | Retro | 1,480 | 50% | 740 | 0.10 | 0.08 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 9.9 |
| 376 | CompressedAir | Compressed Air - Custom | Biz-Custom | Food Service | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.2 |
| 377 | Cooking | Commercial Griddles | Biz-Prescriptive | Food Service | ROB | 15,825 | 12% | 1,910 | 0.27 | 0.31 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 378 | Cooking | Convection Ovens | Biz-Prescriptive | Food Service | ROB | 9,839 | 11% | 1,065 | 0.15 | 0.17 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 379 | Cooking | Combination Ovens | Biz-Prescriptive | Food Service | ROB | 23,958 | 38% | 9,058 | 1.29 | 1.49 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.2 |
| 380 | Cooking | Commercial Fryers | Biz-Prescriptive | Food Service | ROB | 18,955 | 17% | 3,274 | 0.47 | 0.54 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 381 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Food Service | ROB | 17,846 | 55% | 9,863 | 1.40 | 1.62 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 382 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Food Service | ROB | 13,697 | 68% | 9,314 | 1.33 | 1.53 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.6 |
| 383 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Food Service | ROB | 4,383 | 60% | 2,630 | 0.37 | 0.43 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.0 |
| 384 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Food Service | ROB | 39,306 | 44% | 17,369 | 2.93 | 2.72 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.8 |
| 385 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Food Service | ROB | 26,901 | 32% | 8,586 | 1.45 | 1.35 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.2 |
| 386 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Food Service | ROB | 680 | 15% | 100 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 1 | 22% | 10% | 0.8 | 0.3 | 0.5 |
| 387 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Food Service | ROB | 680 | 19% | 132 | 0.07 | 0.00 | 15 | $215 | 100% | 40% | 1 | 22% | 10% | 0.8 | 0.3 | 0.5 |
| 388 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Food Service | ROB | 680 | 31% | 211 | 0.11 | 0.00 | 15 | $399 | 100% | 40% | 1 | 22% | 10% | 0.8 | 0.3 | 0.4 |
| 389 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Food Service | ROB | 747 | 8% | 57 | 0.03 | 0.00 | 15 | $59 | 100% | 40% | 2 | 22% | 10% | 0.8 | 0.4 | 0.8 |
| 390 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Food Service | ROB | 747 | 12% | 90 | 0.05 | 0.00 | 15 | $97 | 100% | 40% | 2 | 22% | 10% | 0.8 | 0.4 | 0.7 |
| 391 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Food Service | ROB | 747 | 22% | 167 | 0.08 | 0.00 | 15 | $204 | 100% | 40% | 2 | 22% | 10% | 0.8 | 0.4 | 0.6 |
| 392 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Food Service | Retro | 822 | 7% | 58 | 0.03 | 0.00 | 3 | $5 | 100% | 40% | 3 | 44% | 50% | 0.8 | 0.6 | 2.1 |
| 393 | Cooling | Air Side Economizer | Biz-Custom | Food Service | Retro | 680 | 20% | 136 | 0.07 | 0.00 | 15 | $153 | 100% | 40% | 4 | 44% | 25% | 0.8 | 0.4 | 0.7 |
| 394 | Cooling | Advanced Rooftop Controls | Biz-Custom | Food Service | Retro | 7,672 | 56% | 4,281 | 2.18 | 0.04 | 15 | $2,950 | 100% | 40% | 5 | 44% | 20% | 0.8 | 0.5 | 1.1 |
| 395 | Cooling | HVAC Occupancy Controls | Biz-Custom | Food Service | Retro | 711 | 20% | 142 | 0.07 | 0.00 | 15 | $537 | 100% | 40% | 6 | 44% | 10% | 0.8 | 0.3 | 0.2 |
| 396 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Food Service | ROB | 705 | 13% | 88 | 0.04 | 0.00 | 15 | $115 | 100% | 40% | 7 | 25% | 10% | 0.8 | 0.3 | 0.6 |
| 397 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Food Service | ROB | 705 | 22% | 157 | 0.08 | 0.00 | 15 | $514 | 100% | 40% | 7 | 25% | 10% | 0.8 | 0.3 | 0.2 |
| 398 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Food Service | ROB | 705 | 33% | 235 | 0.12 | 0.00 | 15 | $631 | 100% | 40% | 7 | 25% | 10% | 0.8 | 0.3 | 0.3 |
| 399 | Cooling | Smart Thermostat | Biz-Prescriptive | Food Service | ROB | 2,818 | 14% | 399 | 0.20 | 0.00 | 11 | $175 | 100% | 40% | 8 | 25% | 10% | 0.8 | 0.5 | 1.4 |
| 400 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Food Service | ROB | 909 | 7% | 66 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 31% | 20% | 0.8 | 0.4 | 0.4 |
| 401 | Cooling | Air Cooled Chiller | Biz-Custom | Food Service | ROB | 720 | 9% | 65 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 0% | 10% | 0.8 | 0.3 | 0.6 |
| 402 | Cooling | Water Cooled Chiller | Biz-Custom | Food Service | ROB | 362 | 23% | 82 | 0.04 | 0.00 | 23 | $126 | 100% | 40% | 11 | 0% | 10% | 0.8 | 0.3 | 0.7 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 403 | Cooling | Window Film | Biz-Custom | Food Service | Retro | 6,000 | 4% | 264 | 0.13 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 404 | Cooling | Triple Pane Windows | Biz-Custom | Food Service | Retro | 6,000 | 6% | 360 | 0.18 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 405 | Cooling | Energy Recovery Ventilator | Biz-Custom | Food Service | Retro | 747 | 0% | 0 | 0.00 | 0.00 | 15 | $1,047 | 100% |  | 13 | 100% | 2% | 0.8 | 0.7 | 0.0 |
| 406 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Food Service | ROB | 2,040 | 4% | 72 | 0.01 | 0.01 | 15 | $135 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.4 |
| 407 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Food Service | ROB | 2,040 | 12% | 238 | 0.04 | 0.05 | 15 | $446 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.4 |
| 408 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Food Service | ROB | 2,040 | 17% | 354 | 0.06 | 0.07 | 15 | $520 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.5 |
| 409 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,283 | 6% | 139 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 2 | 19% | 10% | 0.8 | 0.5 | 1.0 |
| 410 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,283 | 11% | 259 | 0.04 | 0.05 | 15 | $171 | 100% | 40% | 2 | 19% | 10% | 0.8 | 0.5 | 1.1 |
| 411 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,362 | 7% | 154 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 3 | 18% | 10% | 0.8 | 0.5 | 1.1 |
| 412 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,362 | 12% | 280 | 0.05 | 0.06 | 15 | $182 | 100% | 40% | 3 | 18% | 10% | 0.8 | 0.5 | 1.1 |
| 413 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,473 | 7% | 170 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 4 | 18% | 10% | 0.8 | 0.5 | 1.3 |
| 414 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Food Service | ROB | 2,473 | 12% | 307 | 0.05 | 0.06 | 15 | $202 | 100% | 40% | 4 | 18% | 10% | 0.8 | 0.5 | 1.1 |
| 415 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Food Service | ROB | 1,599 | 3% | 55 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 0.6 |
| 416 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Food Service | ROB | 1,599 | 7% | 116 | 0.02 | 0.02 | 25 | $108 | 100% | 40% | 5 | 6% | 20% | 0.8 | 0.4 | 1.2 |
| 417 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Food Service | ROB | 2,487 | 8% | 191 | 0.03 | 0.04 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.5 | 1.0 |
| 418 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Food Service | ROB | 5,521 | 67% | 3,698 | 0.62 | 0.58 | 15 | $1,115 | 100% | 40% | 1 | 100% | 33% | 0.7 | 0.5 | 2.4 |
| 419 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Food Service | Retro | 5,521 | 2% | 110 | 0.02 | 0.02 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.6 |
| 420 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Food Service | ROB | 18,059 | 54% | 9,789 | 1.65 | 1.54 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 46.4 |
| 421 | HotWater | Faucet Aerator | Biz-Prescriptive | Food Service | Retro | 5,521 | 67% | 3,698 | 0.62 | 0.58 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 2.4 |
| 422 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Food Service | ROB | 1,868 | 20% | 380 | 0.06 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.1 |
| 423 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Food Service | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 424 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Food Service | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 425 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Food Service | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 426 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Food Service | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 427 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Food Service | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 428 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Food Service | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 429 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Food Service | Retro | 320 | 68% | 216 | 0.03 | 0.03 | 9 | $27 | 100% | 40% | 1 | 10% | 75% | 0.8 | 0.8 | 3.7 |
| 430 | Lighting_Int | LED interior directional | Biz-Prescriptive | Food Service | Retro | 230 | 74% | 170 | 0.03 | 0.02 | 9 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.3 |
| 431 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Food Service | Retro | 206 | 45% | 92 | 0.01 | 0.01 | 9 | $2 | 100% | 40% | 3 | 47% | 45% | 0.8 | 0.7 | 22.5 |
| 432 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Food Service | Retro | 467 | 50% | 234 | 0.04 | 0.03 | 9 | $70 | 100% | 40% | 3 | 47% | 45% | 0.8 | 0.6 | 1.5 |
| 433 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Food Service | Retro | 926 | 61% | 563 | 0.09 | 0.07 | 9 | $44 | 100% | 40% | 4 | 25% | 35% | 0.8 | 0.7 | 5.9 |
| 434 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Food Service | Retro | 4,346 | 68% | 2,957 | 0.45 | 0.39 | 9 | $330 | 100% | 40% | 5 | 17% | 35% | 0.8 | 0.7 | 4.1 |
| 435 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Food Service | Retro | 172 | 100% | 172 | 0.03 | 0.02 | 11 | $4 | 100% | 40% | 6 | 47% | 0% | 0.8 | 0.7 | 23.2 |
| 436 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Food Service | Retro | 1,005 | 30% | 301 | 0.05 | 0.04 | 10 | $58 | 100% | 40% | 7 | 90% | 20% | 0.8 | 0.6 | 2.6 |
| 437 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Food Service | Retro | 4 | 49% | 2 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 90% | 20% | 0.8 | 0.6 | 2.1 |
| 438 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Food Service | Retro | 785 | 30% | 235 | 0.04 | 0.03 | 15 | $139 | 100% | 40% | 7 | 90% | 20% | 0.8 | 0.5 | 1.2 |
| 439 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Food Service | Retro | 66 | 43% | 28 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 440 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Food Service | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 441 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Food Service | Retro | 9,932 | 50% | 4,966 | 0.64 | 0.55 | 20 | $1,180 | 100% | 40% | 2 | 2% | 10% | 0.8 | 0.6 | 3.5 |
| 442 | Misc | High Efficiency Hand Dryers | Biz-Custom | Food Service | Retro | 1,909 | 83% | 1,585 | 0.21 | 0.18 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.6 | 1.6 |
| 443 | Misc | Ozone Commercial Laundry | Biz-Custom | Food Service | Retro | 2,984 | 25% | 746 | 0.10 | 0.08 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 444 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Food Service | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 0.9 |
| 445 | Misc | Miscellaneous Custom | Biz-Custom | Food Service | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 32% | 10% | 0.8 | 0.3 | 0.3 |
| 446 | Motors | Cogged V-Belt | Biz-Custom | Food Service | Retro | 17,237 | 3% | 534 | 0.06 | 0.09 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.0 |
| 447 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Food Service | Retro | 3,805 | 34% | 1,290 | 0.16 | 0.23 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |
| 448 | Motors | Power Drive Systems | Biz-Custom | Food Service | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |
| 449 | Motors | Switch Reluctance Motors | Biz-Custom | Food Service | Retro | 33,406 | 31% | 10,222 | 1.23 | 1.81 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 13.6 |
| 450 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Food Service | Retro | 551 | 40% | 223 | 0.03 | 0.02 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| 451 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Food Service | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 452 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Food Service | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 453 | Office_PC | Energy Star Server | Biz-Custom | Food Service | ROB | 1,621 | 23% | 368 | 0.05 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.2 |
| 454 | Office_PC | Server Virtualization | Biz-Custom | Food Service | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 455 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Food Service | Retro | 86,783 | 18% | 15,778 | 2.05 | 1.74 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 21.7 |
| 456 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Food Service | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 457 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Food Service | Retro | 764 | 47% | 358 | 0.05 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 458 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Food Service | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.6 |
| 459 | Refrigeration | Strip Curtains | Biz-Prescriptive | Food Service | Retro | 88 | 50% | 44 | 0.01 | 0.00 | 4 | $10 | 100% | 40% | 1 | 6% | 30% | 0.7 | 0.5 | 0.9 |
| 460 | Refrigeration | Bare Suction Line | Biz-Custom | Food Service | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 461 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Food Service | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 4% | 25% | 0.7 | 0.4 | 0.4 |
| 462 | Refrigeration | Saturated Suction Controls | Biz-Custom | Food Service | Retro | 831 | 50% | 416 | 0.06 | 0.04 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 463 | Refrigeration | Compressor Retrofit | Biz-Custom | Food Service | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 13% | 25% | 0.7 | 0.4 | 0.2 |
| 464 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Food Service | Retro | 2,884 | 55% | 1,586 | 0.23 | 0.17 | 15 | $305 | 100% | 40% | 6 | 4% | 80% | 0.9 | 0.8 | 3.5 |
| 465 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Food Service | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 4% | 25% | 0.7 | 0.5 | 3.1 |
| 466 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Food Service | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 5% | 25% | 0.7 | 0.4 | 0.8 |
| 467 | Refrigeration | Refrigeration Economizer | Biz-Custom | Food Service | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 18% | 10% | 0.7 | 0.4 | 0.8 |
| 468 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Food Service | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 18% | 75% | 0.8 | 0.8 | 2.1 |
| 469 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Food Service | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 5% | 25% | 0.7 | 0.4 | 0.5 |
| 470 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Food Service | Retro | 2,884 | 55% | 1,586 | 0.23 | 0.17 | 15 | $305 | 100% | 40% | 12 | 3% | 80% | 0.9 | 0.8 | 3.5 |
| 471 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Food Service | Retro | 641 | 38% | 242 | 0.03 | 0.03 | 10 | $102 | 100% | 40% | 13 | 3% | 2% | 0.7 | 0.5 | 1.2 |
| 472 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Food Service | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 18% | 54% | 0.7 | 0.6 | 0.3 |
| 473 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Food Service | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 18% | 54% | 0.7 | 0.6 | 0.1 |
| 474 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Food Service | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 6% | 75% | 0.8 | 0.8 | 7.3 |
| 475 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Food Service | Retro | 2,922 | 50% | 1,453 | 0.21 | 0.16 | 12 | $686 | 100% | 40% | 16 | 6% | 25% | 0.7 | 0.5 | 1.2 |
| 476 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Food Service | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.4 |
| 477 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Food Service | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.1 |
| 478 | Refrigeration | Refrigeration - Custom | Biz-Custom | Food Service | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 479 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Food Service | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 480 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Food Service | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 5% | 44% | 0.7 | 0.6 | 1.6 |
| 481 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Food Service | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 0% | 30% | 0.7 | 0.4 | 0.2 |
| 482 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Food Service | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 11% | 35% | 0.7 | 0.5 | 3.4 |
| 483 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Food Service | Retro | 2,669 | 20% | 534 | 0.08 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 1.9 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 484 | Ventilation | Demand Control Ventilation | Biz-Custom | Food Service | Retro | 2,166 | 43% | 940 | 0.14 | 0.12 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.9 |
| 485 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Food Service | Retro | 19,919 | 82% | 16,287 | 2.46 | 2.16 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.7 |
| 486 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Food Service | Retro | 21,909 | 83% | 18,277 | 2.76 | 2.42 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 3.0 |
| 487 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Food Service | Retro | 23,903 | 82% | 19,579 | 2.95 | 2.59 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.2 |
| 488 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Food Service | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 489 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Food Service | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 490 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Food Service | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.8 |
| 491 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Food Service | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.5 |
| 492 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Food Service | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 1.0 |
| 493 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Health | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 494 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Health | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 495 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Health | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 496 | CompressedAir | AODD Pump Controls | Biz-Custom | Health | Retro | 103,919 | 35% | 36,372 | 4.54 | 3.95 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.3 |
| 497 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Health | Retro | 103,919 | 2% | 2,320 | 0.29 | 0.25 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 498 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Health | Retro | 1,480 | 50% | 740 | 0.09 | 0.08 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.0 |
| 499 | CompressedAir | Compressed Air - Custom | Biz-Custom | Health | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 500 | Cooking | Commercial Griddles | Biz-Prescriptive | Health | ROB | 15,825 | 12% | 1,910 | 0.58 | 0.19 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 501 | Cooking | Convection Ovens | Biz-Prescriptive | Health | ROB | 9,839 | 11% | 1,065 | 0.32 | 0.11 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 502 | Cooking | Combination Ovens | Biz-Prescriptive | Health | ROB | 23,958 | 38% | 9,058 | 2.73 | 0.91 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.3 |
| 503 | Cooking | Commercial Fryers | Biz-Prescriptive | Health | ROB | 18,955 | 17% | 3,274 | 0.99 | 0.33 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 504 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Health | ROB | 17,846 | 55% | 9,863 | 2.98 | 0.99 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 505 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Health | ROB | 13,697 | 68% | 9,314 | 2.81 | 0.94 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.7 |
| 506 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Health | ROB | 4,383 | 60% | 2,630 | 0.79 | 0.27 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.1 |
| 507 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Health | ROB | 39,306 | 44% | 17,369 | 1.76 | 2.02 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 17.3 |
| 508 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Health | ROB | 26,901 | 32% | 8,586 | 0.87 | 1.00 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 5.7 |
| 509 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Health | ROB | 1,260 | 15% | 185 | 0.05 | 0.01 | 15 | $153 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.4 | 0.8 |
| 510 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Health | ROB | 1,260 | 19% | 245 | 0.07 | 0.01 | 15 | $215 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.4 | 0.8 |
| 511 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Health | ROB | 1,260 | 31% | 390 | 0.11 | 0.01 | 15 | $399 | 100% | 40% | 1 | 25% | 10% | 0.8 | 0.4 | 0.7 |
| 512 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Health | ROB | 1,385 | 8% | 107 | 0.03 | 0.00 | 15 | $59 | 100% | 40% | 2 | 25% | 10% | 0.8 | 0.5 | 1.2 |
| 513 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Health | ROB | 1,385 | 12% | 166 | 0.05 | 0.01 | 15 | $97 | 100% | 40% | 2 | 25% | 10% | 0.8 | 0.5 | 1.2 |
| 514 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Health | ROB | 1,385 | 22% | 309 | 0.09 | 0.01 | 15 | $204 | 100% | 40% | 2 | 25% | 10% | 0.8 | 0.5 | 1.0 |
| 515 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Health | Retro | 1,523 | 7% | 107 | 0.03 | 0.00 | 3 | $5 | 100% | 40% | 3 | 50% | 50% | 0.8 | 0.6 | 3.6 |
| 516 | Cooling | Air Side Economizer | Biz-Custom | Health | Retro | 1,260 | 20% | 252 | 0.07 | 0.01 | 15 | $153 | 100% | 40% | 4 | 50% | 25% | 0.8 | 0.5 | 1.1 |
| 517 | Cooling | Advanced Rooftop Controls | Biz-Custom | Health | Retro | 8,760 | 56% | 4,888 | 1.36 | 0.17 | 15 | $2,950 | 100% | 40% | 5 | 50% | 20% | 0.8 | 0.5 | 1.1 |
| 518 | Cooling | HVAC Occupancy Controls | Biz-Custom | Health | Retro | 1,317 | 20% | 263 | 0.07 | 0.01 | 15 | $537 | 100% | 40% | 6 | 50% | 10% | 0.8 | 0.3 | 0.3 |
| 519 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Health | ROB | 1,305 | 13% | 163 | 0.05 | 0.01 | 15 | $115 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.5 | 1.0 |
| 520 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Health | ROB | 1,305 | 22% | 290 | 0.08 | 0.01 | 15 | $514 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 521 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Health | ROB | 1,305 | 33% | 435 | 0.12 | 0.01 | 15 | $631 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.5 |
| 522 | Cooling | Smart Thermostat | Biz-Prescriptive | Health | ROB | 5,222 | 14% | 739 | 0.21 | 0.03 | 11 | $175 | 100% | 40% | 8 | 0% | 10% | 0.8 | 0.6 | 2.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 523 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Health | ROB | 1,684 | 7% | 122 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 0% | 20% | 0.8 | 0.5 | 0.6 |
| 524 | Cooling | Air Cooled Chiller | Biz-Custom | Health | ROB | 1,334 | 9% | 120 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 45% | 10% | 0.8 | 0.4 | 0.9 |
| 525 | Cooling | Water Cooled Chiller | Biz-Custom | Health | ROB | 670 | 23% | 152 | 0.04 | 0.01 | 23 | $126 | 100% | 40% | 11 | 5% | 10% | 0.8 | 0.4 | 1.2 |
| 526 | Cooling | Window Film | Biz-Custom | Health | Retro | 6,000 | 4% | 264 | 0.07 | 0.01 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 527 | Cooling | Triple Pane Windows | Biz-Custom | Health | Retro | 6,000 | 6% | 360 | 0.10 | 0.01 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.5 |
| 528 | Cooling | Energy Recovery Ventilator | Biz-Custom | Health | Retro | 1,385 | 62% | 862 | 0.24 | 0.03 | 15 | $1,046 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.4 | 0.6 |
| 529 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Health | ROB | 2,727 | 4% | 110 | 0.01 | 0.03 | 15 | $135 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.6 |
| 530 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Health | ROB | 2,727 | 13% | 343 | 0.03 | 0.08 | 15 | $446 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.6 |
| 531 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Health | ROB | 2,727 | 19% | 529 | 0.05 | 0.12 | 15 | $520 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.4 | 0.7 |
| 532 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,030 | 6% | 192 | 0.02 | 0.04 | 15 | $100 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.4 |
| 533 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,030 | 12% | 353 | 0.03 | 0.08 | 15 | $171 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.5 |
| 534 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,142 | 7% | 215 | 0.02 | 0.05 | 15 | $100 | 100% | 40% | 3 | 17% | 10% | 0.8 | 0.5 | 1.6 |
| 535 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,142 | 12% | 386 | 0.04 | 0.09 | 15 | $182 | 100% | 40% | 3 | 17% | 10% | 0.8 | 0.5 | 1.6 |
| 536 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,309 | 7% | 239 | 0.02 | 0.06 | 15 | $100 | 100% | 40% | 4 | 17% | 10% | 0.8 | 0.5 | 1.8 |
| 537 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Health | ROB | 3,309 | 13% | 428 | 0.04 | 0.10 | 15 | $202 | 100% | 40% | 4 | 17% | 10% | 0.8 | 0.5 | 1.6 |
| 538 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Health | ROB | 2,208 | 4% | 82 | 0.01 | 0.02 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.4 | 0.8 |
| 539 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Health | ROB | 2,208 | 9% | 195 | 0.02 | 0.05 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.5 | 1.9 |
| 540 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Health | ROB | 3,316 | 10% | 336 | 0.03 | 0.08 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.6 | 1.8 |
| 541 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Health | ROB | 6,995 | 67% | 4,684 | 0.47 | 0.54 | 15 | $1,115 | 100% | 40% | 1 | 100% | 29% | 0.7 | 0.5 | 2.8 |
| 542 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Health | Retro | 6,995 | 2% | 140 | 0.01 | 0.02 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.9 |
| 543 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Health | ROB | 18,059 | 54% | 9,789 | 0.99 | 1.14 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 42.8 |
| 544 | HotWater | Faucet Aerator | Biz-Prescriptive | Health | Retro | 6,995 | 67% | 4,684 | 0.47 | 0.54 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 2.8 |
| 545 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Health | ROB | 1,868 | 20% | 380 | 0.04 | 0.04 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 546 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Health | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 547 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Health | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 548 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Health | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 549 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Health | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 550 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Health | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.22 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 551 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Health | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 552 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Health | Retro | 349 | 68% | 236 | 0.03 | 0.02 | 9 | $27 | 100% | 40% | 1 | 3% | 75% | 0.8 | 0.8 | 3.9 |
| 553 | Lighting_Int | LED interior directional | Biz-Prescriptive | Health | Retro | 251 | 74% | 185 | 0.02 | 0.02 | 9 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.4 |
| 554 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Health | Retro | 225 | 45% | 101 | 0.01 | 0.01 | 9 | $2 | 100% | 40% | 3 | 80% | 45% | 0.8 | 0.7 | 23.7 |
| 555 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Health | Retro | 509 | 50% | 255 | 0.03 | 0.02 | 9 | $70 | 100% | 40% | 3 | 80% | 45% | 0.8 | 0.6 | 1.6 |
| 556 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Health | Retro | 1,009 | 61% | 613 | 0.08 | 0.06 | 9 | $44 | 100% | 40% | 4 | 9% | 35% | 0.8 | 0.7 | 6.2 |
| 557 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Health | Retro | 4,737 | 68% | 3,223 | 0.41 | 0.31 | 9 | $330 | 100% | 40% | 5 | 6% | 35% | 0.8 | 0.7 | 4.3 |
| 558 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Health | Retro | 187 | 100% | 187 | 0.02 | 0.02 | 11 | $4 | 100% | 40% | 6 | 80% | 0% | 0.8 | 0.7 | 24.4 |
| 559 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Health | Retro | 1,095 | 30% | 329 | 0.04 | 0.03 | 10 | $58 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.7 | 2.8 |
| 560 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Health | Retro | 4 | 49% | 2 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.6 | 2.2 |
| 561 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Health | Retro | 855 | 30% | 257 | 0.03 | 0.02 | 15 | $151 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.5 | 1.1 |
| 562 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Health | Retro | 70 | 43% | 30 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 563 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Health | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 564 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Health | Retro | 9,932 | 50% | 4,966 | 0.62 | 0.54 | 20 | $1,180 | 100% | 40% | 2 | 3% | 10% | 0.8 | 0.6 | 3.5 |
| 565 | Misc | High Efficiency Hand Dryers | Biz-Custom | Health | Retro | 1,909 | 83% | 1,585 | 0.20 | 0.17 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.6 | 1.6 |
| 566 | Misc | Ozone Commercial Laundry | Biz-Custom | Health | Retro | 2,984 | 25% | 746 | 0.09 | 0.08 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 567 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Health | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 568 | Misc | Miscellaneous Custom | Biz-Custom | Health | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 1% | 10% | 0.8 | 0.3 | 0.3 |
| 569 | Motors | Cogged V-Belt | Biz-Custom | Health | Retro | 17,237 | 3% | 534 | 0.07 | 0.06 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 0.9 |
| 570 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Health | Retro | 3,805 | 34% | 1,290 | 0.16 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| 571 | Motors | Power Drive Systems | Biz-Custom | Health | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| 572 | Motors | Switch Reluctance Motors | Biz-Custom | Health | Retro | 33,406 | 31% | 10,222 | 1.28 | 1.05 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 12.8 |
| 573 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Health | Retro | 551 | 40% | 223 | 0.03 | 0.02 | 6 | $0 | 100% | | 1 | 5% | 90% | 0.9 | 0.9 | 0.0 |
| 574 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Health | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 575 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Health | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 576 | Office_PC | Energy Star Server | Biz-Custom | Health | ROB | 1,621 | 23% | 368 | 0.05 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.3 |
| 577 | Office_PC | Server Virtualization | Biz-Custom | Health | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 578 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Health | Retro | 86,783 | 18% | 15,778 | 1.97 | 1.71 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 22.0 |
| 579 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Health | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 580 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Health | Retro | 764 | 47% | 358 | 0.04 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 581 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Health | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 582 | Refrigeration | Strip Curtains | Biz-Prescriptive | Health | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 5% | 30% | 0.7 | 0.6 | 0.0 |
| 583 | Refrigeration | Bare Suction Line | Biz-Custom | Health | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.6 |
| 584 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Health | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 4% | 25% | 0.7 | 0.4 | 0.4 |
| 585 | Refrigeration | Saturated Suction Controls | Biz-Custom | Health | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 586 | Refrigeration | Compressor Retrofit | Biz-Custom | Health | Retro | 813 | 20% | 163 | 0.03 | 0.02 | 15 | $477 | 100% | 40% | 5 | 12% | 25% | 0.7 | 0.4 | 0.2 |
| 587 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Health | Retro | 2,884 | 55% | 1,586 | 0.25 | 0.18 | 15 | $305 | 100% | 40% | 6 | 3% | 80% | 0.9 | 0.8 | 3.5 |
| 588 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Health | Retro | 2,236 | 32% | 716 | 0.11 | 0.08 | 15 | $155 | 100% | 40% | 7 | 3% | 25% | 0.7 | 0.5 | 3.1 |
| 589 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Health | Retro | 2,960 | 50% | 1,480 | 0.23 | 0.17 | 15 | $1,170 | 100% | 40% | 8 | 5% | 25% | 0.7 | 0.4 | 0.9 |
| 590 | Refrigeration | Refrigeration Economizer | Biz-Custom | Health | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 17% | 10% | 0.7 | 0.4 | 0.8 |
| 591 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Health | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 17% | 25% | 0.7 | 0.5 | 2.1 |
| 592 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Health | Retro | 1,584 | 36% | 578 | 0.09 | 0.07 | 12 | $686 | 100% | 40% | 11 | 5% | 25% | 0.7 | 0.4 | 0.5 |
| 593 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Health | Retro | 2,884 | 55% | 1,586 | 0.25 | 0.18 | 15 | $305 | 100% | 40% | 12 | 3% | 80% | 0.9 | 0.8 | 3.5 |
| 594 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Health | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 3% | 2% | 0.7 | 0.4 | 0.8 |
| 595 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Health | ROB | 2,140 | 29% | 629 | 0.10 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 17% | 54% | 0.7 | 0.6 | 0.3 |
| 596 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Health | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 17% | 54% | 0.7 | 0.6 | 0.1 |
| 597 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Health | Retro | 2,016 | 68% | 1,361 | 0.21 | 0.16 | 10 | $91 | 100% | 40% | 15 | 6% | 25% | 0.7 | 0.6 | 7.4 |
| 598 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Health | Retro | 2,922 | 50% | 1,453 | 0.23 | 0.17 | 12 | $686 | 100% | 40% | 16 | 6% | 25% | 0.7 | 0.5 | 1.2 |
| 599 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Health | ROB | 6,374 | 20% | 1,275 | 0.20 | 0.15 | 12 | $1,651 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.4 |
| 600 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Health | ROB | 4,522 | 7% | 305 | 0.05 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.1 |
| 601 | Refrigeration | Refrigeration - Custom | Biz-Custom | Health | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 602 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Health | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 603 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Health | ROB | 6,993 | 10% | 721 | 0.11 | 0.08 | 10 | $222 | 100% | 40% | 20 | 6% | 44% | 0.7 | 0.6 | 1.6 |
| 604 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Health | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 3% | 30% | 0.7 | 0.4 | 0.2 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 605 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Health | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 10% | 35% | 0.7 | 0.5 | 3.5 |
| 606 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Health | Retro | 2,639 | 20% | 528 | 0.07 | 0.06 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.6 |
| 607 | Ventilation | Demand Control Ventilation | Biz-Custom | Health | Retro | 2,166 | 43% | 940 | 0.12 | 0.11 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.7 |
| 608 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Health | Retro | 19,919 | 82% | 16,287 | 2.09 | 1.88 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.6 |
| 609 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Health | Retro | 21,909 | 83% | 18,277 | 2.35 | 2.11 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 2.9 |
| 610 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Health | Retro | 23,903 | 82% | 19,579 | 2.51 | 2.26 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.1 |
| 611 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Health | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 612 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Health | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 613 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Health | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.6 |
| 614 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Health | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 615 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Health | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 0.9 |
| 616 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Lodging | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.4 |
| 617 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Lodging | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 618 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Lodging | ROB | 1,583 | 21% | 329 | 0.04 | 0.05 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.6 |
| 619 | CompressedAir | AODD Pump Controls | Biz-Custom | Lodging | Retro | 103,919 | 35% | 36,372 | 4.51 | 5.04 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.5 |
| 620 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Lodging | Retro | 103,919 | 2% | 2,320 | 0.29 | 0.32 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 621 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Lodging | Retro | 1,480 | 50% | 740 | 0.09 | 0.10 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.2 |
| 622 | CompressedAir | Compressed Air - Custom | Biz-Custom | Lodging | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 623 | Cooking | Commercial Griddles | Biz-Prescriptive | Lodging | ROB | 15,825 | 12% | 1,910 | 0.60 | 0.19 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 624 | Cooking | Convection Ovens | Biz-Prescriptive | Lodging | ROB | 9,839 | 11% | 1,065 | 0.34 | 0.10 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 625 | Cooking | Combination Ovens | Biz-Prescriptive | Lodging | ROB | 23,958 | 38% | 9,058 | 2.86 | 0.89 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.3 |
| 626 | Cooking | Commercial Fryers | Biz-Prescriptive | Lodging | ROB | 18,955 | 17% | 3,274 | 1.04 | 0.32 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 627 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Lodging | ROB | 17,846 | 55% | 9,863 | 3.12 | 0.97 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.5 |
| 628 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Lodging | ROB | 13,697 | 68% | 9,314 | 2.95 | 0.91 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.7 |
| 629 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Lodging | ROB | 4,383 | 60% | 2,630 | 0.83 | 0.26 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.1 |
| 630 | Cooking | Dishwasher  Low Temp Door (Energy Star) | Biz-Prescriptive | Lodging | ROB | 39,306 | 44% | 17,369 | 1.79 | 2.76 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 17.9 |
| 631 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Lodging | ROB | 26,901 | 32% | 8,586 | 0.89 | 1.37 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 5.9 |
| 632 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Lodging | ROB | 837 | 15% | 123 | 0.04 | 0.00 | 15 | $153 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.6 |
| 633 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Lodging | ROB | 837 | 19% | 163 | 0.05 | 0.00 | 15 | $215 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.5 |
| 634 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Lodging | ROB | 837 | 31% | 259 | 0.08 | 0.01 | 15 | $399 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.5 |
| 635 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Lodging | ROB | 919 | 8% | 71 | 0.02 | 0.00 | 15 | $59 | 100% | 40% | 2 | 13% | 10% | 0.8 | 0.4 | 0.8 |
| 636 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Lodging | ROB | 919 | 12% | 110 | 0.04 | 0.00 | 15 | $97 | 100% | 40% | 2 | 13% | 10% | 0.8 | 0.4 | 0.8 |
| 637 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Lodging | ROB | 919 | 22% | 205 | 0.07 | 0.00 | 15 | $204 | 100% | 40% | 2 | 13% | 10% | 0.8 | 0.4 | 0.7 |
| 638 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Lodging | Retro | 1,011 | 7% | 71 | 0.02 | 0.00 | 3 | $5 | 100% | 40% | 3 | 26% | 50% | 0.8 | 0.6 | 2.4 |
| 639 | Cooling | Air Side Economizer | Biz-Custom | Lodging | Retro | 837 | 20% | 167 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 4 | 26% | 25% | 0.8 | 0.4 | 0.8 |
| 640 | Cooling | Advanced Rooftop Controls | Biz-Custom | Lodging | Retro | 8,760 | 56% | 4,888 | 1.58 | 0.10 | 15 | $2,950 | 100% | 40% | 5 | 26% | 20% | 0.8 | 0.5 | 1.2 |
| 641 | Cooling | HVAC Occupancy Controls | Biz-Custom | Lodging | Retro | 874 | 20% | 175 | 0.06 | 0.00 | 15 | $537 | 100% | 40% | 6 | 26% | 10% | 0.8 | 0.3 | 0.2 |
| 642 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Lodging | ROB | 867 | 13% | 108 | 0.03 | 0.00 | 15 | $115 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.4 | 0.7 |
| 643 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Lodging | ROB | 867 | 22% | 193 | 0.06 | 0.00 | 15 | $514 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 644 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Lodging | ROB | 867 | 33% | 289 | 0.09 | 0.01 | 15 | $631 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.3 |
| 645 | Cooling | Smart Thermostat | Biz-Prescriptive | Lodging | ROB | 3,466 | 14% | 491 | 0.16 | 0.01 | 11 | $175 | 100% | 40% | 8 | 0% | 10% | 0.8 | 0.6 | 1.5 |
| 646 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Lodging | ROB | 1,118 | 7% | 81 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 15% | 20% | 0.8 | 0.4 | 0.4 |
| 647 | Cooling | Air Cooled Chiller | Biz-Custom | Lodging | ROB | 886 | 9% | 80 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 42% | 10% | 0.8 | 0.3 | 0.6 |
| 648 | Cooling | Water Cooled Chiller | Biz-Custom | Lodging | ROB | 445 | 23% | 101 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 11 | 5% | 10% | 0.8 | 0.3 | 0.8 |
| 649 | Cooling | Window Film | Biz-Custom | Lodging | Retro | 6,000 | 4% | 264 | 0.09 | 0.01 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 650 | Cooling | Triple Pane Windows | Biz-Custom | Lodging | Retro | 6,000 | 6% | 360 | 0.12 | 0.01 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.5 |
| 651 | Cooling | Energy Recovery Ventilator | Biz-Custom | Lodging | Retro | 919 | 0% | 0 | 0.00 | 0.00 | 15 | $1,045 | 100% | | 13 | 100% | 2% | 0.8 | 0.7 | 0.0 |
| 652 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Lodging | ROB | 3,034 | 3% | 100 | 0.01 | 0.02 | 15 | $135 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.5 |
| 653 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Lodging | ROB | 3,034 | 11% | 341 | 0.04 | 0.07 | 15 | $446 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.6 |
| 654 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Lodging | ROB | 3,034 | 16% | 498 | 0.05 | 0.10 | 15 | $520 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.4 | 0.7 |
| 655 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,404 | 6% | 205 | 0.02 | 0.04 | 15 | $100 | 100% | 40% | 2 | 9% | 10% | 0.8 | 0.5 | 1.5 |
| 656 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,404 | 11% | 381 | 0.04 | 0.08 | 15 | $171 | 100% | 40% | 2 | 9% | 10% | 0.8 | 0.5 | 1.6 |
| 657 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,520 | 6% | 225 | 0.02 | 0.05 | 15 | $100 | 100% | 40% | 3 | 9% | 10% | 0.8 | 0.5 | 1.6 |
| 658 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,520 | 12% | 411 | 0.05 | 0.08 | 15 | $182 | 100% | 40% | 3 | 9% | 10% | 0.8 | 0.5 | 1.6 |
| 659 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,676 | 7% | 246 | 0.03 | 0.05 | 15 | $100 | 100% | 40% | 4 | 9% | 10% | 0.8 | 0.6 | 1.8 |
| 660 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Lodging | ROB | 3,676 | 12% | 449 | 0.05 | 0.09 | 15 | $202 | 100% | 40% | 4 | 9% | 10% | 0.8 | 0.5 | 1.6 |
| 661 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Lodging | ROB | 2,343 | 3% | 78 | 0.01 | 0.02 | 25 | $108 | 100% | 40% | 5 | 14% | 20% | 0.8 | 0.4 | 0.8 |
| 662 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Lodging | ROB | 2,343 | 7% | 153 | 0.02 | 0.03 | 25 | $108 | 100% | 40% | 5 | 14% | 20% | 0.8 | 0.5 | 1.5 |
| 663 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Lodging | ROB | 3,703 | 7% | 245 | 0.03 | 0.05 | 8 | $84 | 100% | 40% | 6 | 15% | 20% | 0.8 | 0.6 | 1.3 |
| 664 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Lodging | ROB | 6,347 | 67% | 4,250 | 0.44 | 0.68 | 15 | $1,115 | 100% | 40% | 1 | 100% | 26% | 0.7 | 0.5 | 2.6 |
| 665 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Lodging | Retro | 6,347 | 2% | 127 | 0.01 | 0.02 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.8 |
| 666 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Lodging | ROB | 18,059 | 54% | 9,789 | 1.01 | 1.56 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 44.4 |
| 667 | HotWater | Faucet Aerator | Biz-Prescriptive | Lodging | Retro | 6,347 | 67% | 4,250 | 0.44 | 0.68 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 2.6 |
| 668 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Lodging | ROB | 1,868 | 20% | 380 | 0.04 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 669 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Lodging | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 670 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Lodging | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 671 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Lodging | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 672 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Lodging | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 673 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Lodging | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 674 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Lodging | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 675 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Lodging | Retro | 356 | 68% | 241 | 0.02 | 0.03 | 8 | $27 | 100% | 40% | 1 | 9% | 75% | 0.8 | 0.8 | 3.5 |
| 676 | Lighting_Int | LED interior directional | Biz-Prescriptive | Lodging | Retro | 256 | 74% | 189 | 0.02 | 0.02 | 8 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.3 |
| 677 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Lodging | Retro | 229 | 45% | 103 | 0.01 | 0.01 | 8 | $2 | 100% | 40% | 3 | 46% | 45% | 0.8 | 0.7 | 21.7 |
| 678 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Lodging | Retro | 519 | 50% | 260 | 0.03 | 0.03 | 8 | $70 | 100% | 40% | 3 | 46% | 45% | 0.8 | 0.6 | 1.5 |
| 679 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Lodging | Retro | 1,029 | 61% | 626 | 0.06 | 0.08 | 8 | $44 | 100% | 40% | 4 | 26% | 35% | 0.8 | 0.7 | 5.6 |
| 680 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Lodging | Retro | 4,832 | 68% | 3,288 | 0.32 | 0.42 | 8 | $330 | 100% | 40% | 5 | 17% | 35% | 0.8 | 0.7 | 4.0 |
| 681 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Lodging | Retro | 191 | 100% | 191 | 0.02 | 0.02 | 11 | $4 | 100% | 40% | 6 | 46% | 0% | 0.8 | 0.7 | 24.6 |
| 682 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Lodging | Retro | 1,117 | 30% | 335 | 0.03 | 0.04 | 10 | $58 | 100% | 40% | 7 | 89% | 20% | 0.8 | 0.7 | 2.8 |
| 683 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Lodging | Retro | 4 | 49% | 2 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 89% | 20% | 0.8 | 0.6 | 2.2 |
| 684 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Lodging | Retro | 872 | 30% | 262 | 0.03 | 0.03 | 15 | $154 | 100% | 40% | 7 | 89% | 20% | 0.8 | 0.5 | 1.1 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 685 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Lodging | Retro | 67 | 43% | 29 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 686 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Lodging | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 687 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Lodging | Retro | 9,932 | 50% | 4,966 | 0.62 | 0.69 | 20 | $1,180 | 100% | 40% | 2 | 4% | 10% | 0.8 | 0.6 | 3.6 |
| 688 | Misc | High Efficiency Hand Dryers | Biz-Custom | Lodging | Retro | 262 | 83% | 217 | 0.03 | 0.03 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.3 | 0.2 |
| 689 | Misc | Ozone Commercial Laundry | Biz-Custom | Lodging | Retro | 2,984 | 25% | 746 | 0.09 | 0.10 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 690 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Lodging | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 691 | Misc | Miscellaneous Custom | Biz-Custom | Lodging | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 43% | 10% | 0.8 | 0.3 | 0.3 |
| 692 | Motors | Cogged V-Belt | Biz-Custom | Lodging | Retro | 29,207 | 3% | 905 | 0.11 | 0.10 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.6 |
| 693 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Lodging | Retro | 3,805 | 34% | 1,290 | 0.16 | 0.14 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| 694 | Motors | Power Drive Systems | Biz-Custom | Lodging | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| 695 | Motors | Switch Reluctance Motors | Biz-Custom | Lodging | Retro | 56,602 | 31% | 17,320 | 2.20 | 1.92 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.7 | 21.8 |
| 696 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Lodging | Retro | 551 | 40% | 223 | 0.03 | 0.03 | 6 | $0 | 100% | | 1 | 5% | 90% | 0.9 | 0.9 | 0.0 |
| 697 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Lodging | Retro | 1,086 | 10% | 109 | 0.01 | 0.02 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 698 | Office_NonPC | Plug Load  Occupancy Sensor | Biz-Custom | Lodging | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 699 | Office_PC | Energy Star Server | Biz-Custom | Lodging | ROB | 1,621 | 23% | 368 | 0.05 | 0.05 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.3 |
| 700 | Office_PC | Server Virtualization | Biz-Custom | Lodging | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 701 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Lodging | Retro | 86,783 | 18% | 15,778 | 1.96 | 2.18 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 22.3 |
| 702 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Lodging | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.8 |
| 703 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Lodging | Retro | 764 | 47% | 358 | 0.04 | 0.05 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 3.0 |
| 704 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Lodging | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 705 | Refrigeration | Strip Curtains | Biz-Prescriptive | Lodging | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 10% | 30% | 0.7 | 0.6 | 0.0 |
| 706 | Refrigeration | Bare Suction Line | Biz-Custom | Lodging | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 707 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Lodging | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 7% | 25% | 0.7 | 0.4 | 0.4 |
| 708 | Refrigeration | Saturated Suction Controls | Biz-Custom | Lodging | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 709 | Refrigeration | Compressor Retrofit | Biz-Custom | Lodging | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 23% | 25% | 0.7 | 0.4 | 0.2 |
| 710 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Lodging | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 6% | 80% | 0.9 | 0.8 | 3.5 |
| 711 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Lodging | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 6% | 25% | 0.7 | 0.5 | 3.1 |
| 712 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Lodging | Retro | 2,960 | 50% | 1,480 | 0.20 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 9% | 25% | 0.7 | 0.4 | 0.8 |
| 713 | Refrigeration | Refrigeration Economizer | Biz-Custom | Lodging | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 32% | 10% | 0.7 | 0.4 | 0.8 |
| 714 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Lodging | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 11% | 25% | 0.7 | 0.5 | 2.1 |
| 715 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Lodging | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 3% | 25% | 0.7 | 0.4 | 0.5 |
| 716 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Lodging | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 2% | 80% | 0.9 | 0.8 | 3.5 |
| 717 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Lodging | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 2% | 2% | 0.7 | 0.4 | 0.8 |
| 718 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Lodging | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.3 |
| 719 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Lodging | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.1 |
| 720 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Lodging | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 4% | 25% | 0.7 | 0.6 | 7.3 |
| 721 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Lodging | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 4% | 25% | 0.7 | 0.5 | 1.2 |
| 722 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Lodging | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.4 |
| 723 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Lodging | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.1 |
| 724 | Refrigeration | Refrigeration - Custom | Biz-Custom | Lodging | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 725 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Lodging | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 726 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Lodging | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 10% | 44% | 0.7 | 0.6 | 1.6 |
| 727 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Lodging | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 4% | 30% | 0.7 | 0.4 | 0.2 |
| 728 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Lodging | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 7% | 35% | 0.7 | 0.5 | 3.4 |
| 729 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Lodging | Retro | 2,639 | 20% | 528 | 0.06 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.6 |
| 730 | Ventilation | Demand Control Ventilation | Biz-Custom | Lodging | Retro | 2,166 | 43% | 940 | 0.11 | 0.12 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.8 |
| 731 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Lodging | Retro | 19,919 | 82% | 16,287 | 1.95 | 2.14 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.7 |
| 732 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Lodging | Retro | 21,909 | 83% | 18,277 | 2.19 | 2.40 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 2.9 |
| 733 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Lodging | Retro | 23,903 | 82% | 19,579 | 2.34 | 2.57 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.1 |
| 734 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Lodging | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 15% | 10% | 0.8 | 0.6 | 1.7 |
| 735 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Lodging | Retro | 7,167 | 19% | 1,382 | 0.21 | 0.17 | 5 | $260 | 100% | 40% | 2 | 85% | 20% | 0.8 | 0.6 | 1.4 |
| 736 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Lodging | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.7 |
| 737 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Lodging | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 738 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Lodging | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 0.9 |
| 739 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Retail | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 740 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Retail | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 741 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Retail | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 742 | CompressedAir | AODD Pump Controls | Biz-Custom | Retail | Retro | 103,919 | 35% | 36,372 | 3.91 | 4.19 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.1 |
| 743 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Retail | Retro | 103,919 | 2% | 2,320 | 0.25 | 0.27 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 1.9 |
| 744 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Retail | Retro | 1,480 | 50% | 740 | 0.08 | 0.09 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 9.9 |
| 745 | CompressedAir | Compressed Air - Custom | Biz-Custom | Retail | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.2 |
| 746 | Cooking | Commercial Griddles | Biz-Prescriptive | Retail | ROB | 15,825 | 12% | 1,910 | 0.47 | 0.20 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 747 | Cooking | Convection Ovens | Biz-Prescriptive | Retail | ROB | 9,839 | 11% | 1,065 | 0.26 | 0.11 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 748 | Cooking | Combination Ovens | Biz-Prescriptive | Retail | ROB | 23,958 | 38% | 9,058 | 2.21 | 0.96 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.3 |
| 749 | Cooking | Commercial Fryers | Biz-Prescriptive | Retail | ROB | 18,955 | 17% | 3,274 | 0.80 | 0.35 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 750 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Retail | ROB | 17,846 | 55% | 9,863 | 2.41 | 1.05 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 751 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Retail | ROB | 13,697 | 68% | 9,314 | 2.28 | 0.99 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.7 |
| 752 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Retail | ROB | 4,383 | 60% | 2,630 | 0.64 | 0.28 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.1 |
| 753 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Retail | ROB | 39,306 | 44% | 17,369 | 2.27 | 2.25 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 17.9 |
| 754 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Retail | ROB | 26,901 | 32% | 8,586 | 1.12 | 1.11 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 5.9 |
| 755 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Retail | ROB | 652 | 15% | 96 | 0.04 | 0.00 | 15 | $153 | 100% | 40% | 1 | 15% | 10% | 0.8 | 0.3 | 0.5 |
| 756 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Retail | ROB | 652 | 19% | 127 | 0.05 | 0.00 | 15 | $215 | 100% | 40% | 1 | 15% | 10% | 0.8 | 0.3 | 0.4 |
| 757 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Retail | ROB | 652 | 31% | 202 | 0.08 | 0.00 | 15 | $399 | 100% | 40% | 1 | 15% | 10% | 0.8 | 0.3 | 0.4 |
| 758 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Retail | ROB | 716 | 8% | 55 | 0.02 | 0.00 | 15 | $59 | 100% | 40% | 2 | 15% | 10% | 0.8 | 0.4 | 0.7 |
| 759 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Retail | ROB | 716 | 12% | 86 | 0.03 | 0.00 | 15 | $97 | 100% | 40% | 2 | 15% | 10% | 0.8 | 0.4 | 0.7 |
| 760 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Retail | ROB | 716 | 22% | 160 | 0.07 | 0.00 | 15 | $204 | 100% | 40% | 2 | 15% | 10% | 0.8 | 0.3 | 0.6 |
| 761 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Retail | Retro | 788 | 7% | 55 | 0.02 | 0.00 | 3 | $5 | 100% | 40% | 3 | 29% | 50% | 0.8 | 0.6 | 2.0 |
| 762 | Cooling | Air Side Economizer | Biz-Custom | Retail | Retro | 652 | 20% | 130 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 4 | 29% | 25% | 0.8 | 0.4 | 0.6 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 763 | Cooling | Advanced Rooftop Controls | Biz-Custom | Retail | Retro | 6,683 | 56% | 3,729 | 1.52 | 0.06 | 15 | $2,950 | 100% | 40% | 5 | 29% | 20% | 0.8 | 0.4 | 0.9 |
| 764 | Cooling | HVAC Occupancy Controls | Biz-Custom | Retail | Retro | 681 | 20% | 136 | 0.06 | 0.00 | 15 | $537 | 100% | 40% | 6 | 29% | 10% | 0.8 | 0.3 | 0.2 |
| 765 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Retail | ROB | 675 | 13% | 84 | 0.03 | 0.00 | 15 | $115 | 100% | 40% | 7 | 18% | 10% | 0.8 | 0.3 | 0.5 |
| 766 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Retail | ROB | 675 | 22% | 150 | 0.06 | 0.00 | 15 | $514 | 100% | 40% | 7 | 18% | 10% | 0.8 | 0.3 | 0.2 |
| 767 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Retail | ROB | 675 | 33% | 225 | 0.09 | 0.00 | 15 | $631 | 100% | 40% | 7 | 18% | 10% | 0.8 | 0.3 | 0.3 |
| 768 | Cooling | Smart Thermostat | Biz-Prescriptive | Retail | ROB | 2,702 | 14% | 383 | 0.16 | 0.01 | 11 | $175 | 100% | 40% | 8 | 18% | 10% | 0.8 | 0.5 | 1.3 |
| 769 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Retail | ROB | 872 | 7% | 63 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 18% | 20% | 0.8 | 0.4 | 0.3 |
| 770 | Cooling | Air Cooled Chiller | Biz-Custom | Retail | ROB | 690 | 9% | 62 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 32% | 10% | 0.8 | 0.3 | 0.5 |
| 771 | Cooling | Water Cooled Chiller | Biz-Custom | Retail | ROB | 347 | 23% | 79 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 11 | 4% | 10% | 0.8 | 0.3 | 0.6 |
| 772 | Cooling | Window Film | Biz-Custom | Retail | Retro | 6,000 | 4% | 264 | 0.11 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 773 | Cooling | Triple Pane Windows | Biz-Custom | Retail | Retro | 6,000 | 6% | 360 | 0.15 | 0.01 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 774 | Cooling | Energy Recovery Ventilator | Biz-Custom | Retail | Retro | 716 | 42% | 298 | 0.12 | 0.00 | 15 | $1,044 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.2 | 0.2 |
| 775 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Retail | ROB | 1,847 | 4% | 66 | 0.01 | 0.01 | 15 | $135 | 100% | 40% | 1 | 28% | 10% | 0.8 | 0.3 | 0.4 |
| 776 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Retail | ROB | 1,847 | 12% | 218 | 0.03 | 0.05 | 15 | $446 | 100% | 40% | 1 | 28% | 10% | 0.8 | 0.3 | 0.4 |
| 777 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Retail | ROB | 1,847 | 18% | 326 | 0.04 | 0.07 | 15 | $520 | 100% | 40% | 1 | 28% | 10% | 0.8 | 0.3 | 0.5 |
| 778 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,064 | 6% | 127 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 2 | 16% | 10% | 0.8 | 0.4 | 0.9 |
| 779 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,064 | 11% | 235 | 0.03 | 0.05 | 15 | $171 | 100% | 40% | 2 | 16% | 10% | 0.8 | 0.5 | 1.0 |
| 780 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,137 | 7% | 140 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 3 | 15% | 10% | 0.8 | 0.5 | 1.1 |
| 781 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,137 | 12% | 255 | 0.03 | 0.06 | 15 | $182 | 100% | 40% | 3 | 15% | 10% | 0.8 | 0.5 | 1.0 |
| 782 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,239 | 7% | 155 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 4 | 15% | 10% | 0.8 | 0.5 | 1.2 |
| 783 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Retail | ROB | 2,239 | 13% | 280 | 0.04 | 0.06 | 15 | $202 | 100% | 40% | 4 | 15% | 10% | 0.8 | 0.5 | 1.0 |
| 784 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Retail | ROB | 1,455 | 4% | 51 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 7% | 20% | 0.8 | 0.4 | 0.5 |
| 785 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Retail | ROB | 1,455 | 8% | 110 | 0.01 | 0.02 | 25 | $108 | 100% | 40% | 5 | 7% | 20% | 0.8 | 0.4 | 1.1 |
| 786 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Retail | ROB | 2,250 | 8% | 182 | 0.02 | 0.04 | 8 | $84 | 100% | 40% | 6 | 10% | 20% | 0.8 | 0.5 | 1.0 |
| 787 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Retail | ROB | 4,687 | 67% | 3,139 | 0.41 | 0.41 | 15 | $1,115 | 100% | 40% | 1 | 100% | 23% | 0.7 | 0.5 | 1.9 |
| 788 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Retail | Retro | 4,687 | 2% | 94 | 0.01 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.3 |
| 789 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Retail | ROB | 18,059 | 54% | 9,789 | 1.28 | 1.27 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 44.2 |
| 790 | HotWater | Faucet Aerator | Biz-Prescriptive | Retail | Retro | 4,687 | 67% | 3,139 | 0.41 | 0.41 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 1.9 |
| 791 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Retail | ROB | 1,868 | 20% | 380 | 0.05 | 0.05 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 792 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Retail | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 793 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Retail | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 794 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Retail | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 795 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Retail | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 796 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Retail | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 797 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Retail | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 798 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Retail | Retro | 238 | 68% | 161 | 0.02 | 0.02 | 12 | $27 | 100% | 40% | 1 | 4% | 75% | 0.8 | 0.8 | 3.3 |
| 799 | Lighting_Int | LED interior directional | Biz-Prescriptive | Retail | Retro | 171 | 74% | 126 | 0.01 | 0.01 | 12 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.2 |
| 800 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Retail | Retro | 153 | 45% | 68 | 0.01 | 0.01 | 12 | $2 | 100% | 40% | 3 | 75% | 45% | 0.8 | 0.7 | 20.0 |
| 801 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Retail | Retro | 346 | 50% | 173 | 0.02 | 0.02 | 12 | $70 | 100% | 40% | 3 | 75% | 45% | 0.8 | 0.6 | 1.4 |
| 802 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Retail | Retro | 687 | 61% | 417 | 0.04 | 0.04 | 12 | $44 | 100% | 40% | 4 | 12% | 35% | 0.8 | 0.7 | 5.2 |
| 803 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Retail | Retro | 3,225 | 68% | 2,194 | 0.23 | 0.23 | 12 | $330 | 100% | 40% | 5 | 8% | 35% | 0.8 | 0.7 | 3.7 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **804** | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Retail | Retro | 128 | 100% | 128 | 0.01 | 0.01 | 11 | $4 | 100% | 40% | 6 | 75% | 0% | 0.8 | 0.7 | 16.4 |
| **805** | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Retail | Retro | 746 | 30% | 224 | 0.02 | 0.02 | 10 | $58 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.6 | 1.9 |
| **806** | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Retail | Retro | 3 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.6 | 1.5 |
| **807** | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Retail | Retro | 582 | 30% | 175 | 0.02 | 0.02 | 15 | $103 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.5 | 1.1 |
| **808** | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Retail | Retro | 67 | 43% | 29 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| **809** | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Retail | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| **810** | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Retail | Retro | 9,932 | 50% | 4,966 | 0.53 | 0.57 | 20 | $1,180 | 100% | 40% | 2 | 0% | 10% | 0.8 | 0.6 | 3.5 |
| **811** | Misc | High Efficiency Hand Dryers | Biz-Custom | Retail | Retro | 1,909 | 83% | 1,585 | 0.17 | 0.18 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.6 | 1.6 |
| **812** | Misc | Ozone Commercial Laundry | Biz-Custom | Retail | Retro | 2,984 | 25% | 746 | 0.08 | 0.09 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| **813** | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Retail | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| **814** | Misc | Miscellaneous Custom | Biz-Custom | Retail | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 39% | 10% | 0.8 | 0.3 | 0.3 |
| **815** | Motors | Cogged V-Belt | Biz-Custom | Retail | Retro | 14,670 | 3% | 455 | 0.06 | 0.05 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.4 | 0.8 |
| **816** | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Retail | Retro | 3,805 | 34% | 1,290 | 0.18 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| **817** | Motors | Power Drive Systems | Biz-Custom | Retail | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.1 |
| **818** | Motors | Switch Reluctance Motors | Biz-Custom | Retail | Retro | 28,430 | 31% | 8,700 | 1.22 | 0.88 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 11.0 |
| **819** | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Retail | Retro | 551 | 40% | 223 | 0.02 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| **820** | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Retail | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| **821** | Office_NonPC | Plug Load  Occupancy Sensor | Biz-Custom | Retail | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| **822** | Office_PC | Energy Star Server | Biz-Custom | Retail | ROB | 1,621 | 23% | 368 | 0.04 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.2 |
| **823** | Office_PC | Server Virtualization | Biz-Custom | Retail | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| **824** | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Retail | Retro | 86,783 | 18% | 15,778 | 1.70 | 1.82 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 21.7 |
| **825** | Office_PC | High Efficiency CRAC unit | Biz-Custom | Retail | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| **826** | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Retail | Retro | 764 | 47% | 358 | 0.04 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| **827** | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Retail | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.6 |
| **828** | Refrigeration | Strip Curtains | Biz-Prescriptive | Retail | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 6% | 30% | 0.7 | 0.6 | 0.0 |
| **829** | Refrigeration | Bare Suction Line | Biz-Custom | Retail | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| **830** | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Retail | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 4% | 25% | 0.7 | 0.4 | 0.4 |
| **831** | Refrigeration | Saturated Suction Controls | Biz-Custom | Retail | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| **832** | Refrigeration | Compressor Retrofit | Biz-Custom | Retail | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 13% | 25% | 0.7 | 0.4 | 0.2 |
| **833** | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Retail | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 4% | 80% | 0.9 | 0.8 | 3.5 |
| **834** | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Retail | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 4% | 25% | 0.7 | 0.5 | 3.1 |
| **835** | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Retail | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 5% | 25% | 0.7 | 0.4 | 0.8 |
| **836** | Refrigeration | Refrigeration Economizer | Biz-Custom | Retail | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 18% | 10% | 0.7 | 0.4 | 0.8 |
| **837** | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Retail | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 18% | 75% | 0.8 | 0.8 | 2.1 |
| **838** | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Retail | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 5% | 25% | 0.7 | 0.4 | 0.5 |
| **839** | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Retail | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 3% | 80% | 0.9 | 0.8 | 3.5 |
| **840** | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Retail | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 3% | 2% | 0.7 | 0.4 | 0.8 |
| **841** | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Retail | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 17% | 54% | 0.7 | 0.6 | 0.3 |
| **842** | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Retail | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 17% | 54% | 0.7 | 0.6 | 0.1 |
| **843** | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Retail | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 6% | 75% | 0.8 | 0.8 | 7.3 |
| **844** | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Retail | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 6% | 25% | 0.7 | 0.5 | 1.2 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 845 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Retail | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.4 |
| 846 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Retail | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.1 |
| 847 | Refrigeration | Refrigeration - Custom | Biz-Custom | Retail | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 848 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Retail | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 849 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Retail | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 3% | 44% | 0.7 | 0.6 | 1.6 |
| 850 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Retail | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 3% | 30% | 0.7 | 0.4 | 0.2 |
| 851 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Retail | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 11% | 35% | 0.7 | 0.5 | 3.4 |
| 852 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Retail | Retro | 2,798 | 20% | 560 | 0.08 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.6 | 2.7 |
| 853 | Ventilation | Demand Control Ventilation | Biz-Custom | Retail | Retro | 2,166 | 43% | 940 | 0.13 | 0.11 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.8 |
| 854 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Retail | Retro | 19,919 | 82% | 16,287 | 2.20 | 1.91 | 15 | $4,130 | 100% | 40% | 3 | 10% | 32% | 0.8 | 0.6 | 2.7 |
| 855 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Retail | Retro | 21,909 | 83% | 18,277 | 2.47 | 2.14 | 15 | $4,190 | 100% | 40% | 4 | 10% | 32% | 0.8 | 0.6 | 2.9 |
| 856 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Retail | Retro | 23,903 | 82% | 19,579 | 2.64 | 2.29 | 15 | $4,230 | 100% | 40% | 5 | 10% | 32% | 0.8 | 0.6 | 3.1 |
| 857 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Retail | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 858 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Retail | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 859 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Retail | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.7 |
| 860 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Retail | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 861 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Retail | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 0.9 |
| 862 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Office | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 863 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Office | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 864 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Office | ROB | 1,583 | 21% | 329 | 0.05 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.6 |
| 865 | CompressedAir | AODD Pump Controls | Biz-Custom | Office | Retro | 103,919 | 35% | 36,372 | 5.33 | 4.22 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.4 |
| 866 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Office | Retro | 103,919 | 2% | 2,320 | 0.34 | 0.27 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 867 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Office | Retro | 1,480 | 50% | 740 | 0.11 | 0.09 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.1 |
| 868 | CompressedAir | Compressed Air - Custom | Biz-Custom | Office | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 869 | Cooking | Commercial Griddles | Biz-Prescriptive | Office | ROB | 15,825 | 12% | 1,910 | 0.97 | 0.24 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 870 | Cooking | Convection Ovens | Biz-Prescriptive | Office | ROB | 9,839 | 11% | 1,065 | 0.54 | 0.13 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 871 | Cooking | Combination Ovens | Biz-Prescriptive | Office | ROB | 23,958 | 38% | 9,058 | 4.60 | 1.14 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.5 |
| 872 | Cooking | Commercial Fryers | Biz-Prescriptive | Office | ROB | 18,955 | 17% | 3,274 | 1.66 | 0.41 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.5 |
| 873 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Office | ROB | 17,846 | 55% | 9,863 | 5.01 | 1.24 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.6 |
| 874 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Office | ROB | 13,697 | 68% | 9,314 | 4.73 | 1.17 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 5.4 |
| 875 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Office | ROB | 4,383 | 60% | 2,630 | 1.34 | 0.33 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.2 |
| 876 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Office | ROB | 39,306 | 44% | 17,369 | 2.91 | 2.59 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.6 |
| 877 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Office | ROB | 26,901 | 32% | 8,586 | 1.44 | 1.28 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.1 |
| 878 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Office | ROB | 788 | 15% | 116 | 0.07 | 0.00 | 15 | $153 | 100% | 40% | 1 | 26% | 10% | 0.8 | 0.3 | 0.6 |
| 879 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Office | ROB | 788 | 19% | 153 | 0.09 | 0.00 | 15 | $215 | 100% | 40% | 1 | 26% | 10% | 0.8 | 0.3 | 0.6 |
| 880 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Office | ROB | 788 | 31% | 244 | 0.14 | 0.00 | 15 | $399 | 100% | 40% | 1 | 26% | 10% | 0.8 | 0.3 | 0.5 |
| 881 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Office | ROB | 865 | 8% | 67 | 0.04 | 0.00 | 15 | $59 | 100% | 40% | 2 | 26% | 10% | 0.8 | 0.4 | 0.9 |
| 882 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Office | ROB | 865 | 12% | 104 | 0.06 | 0.00 | 15 | $97 | 100% | 40% | 2 | 26% | 10% | 0.8 | 0.4 | 0.9 |
| 883 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Office | ROB | 865 | 22% | 193 | 0.11 | 0.00 | 15 | $204 | 100% | 40% | 2 | 26% | 10% | 0.8 | 0.4 | 0.8 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 884 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Office | Retro | 952 | 7% | 67 | 0.04 | 0.00 | 3 | $5 | 100% | 40% | 3 | 51% | 50% | 0.8 | 0.6 | 2.5 |
| 885 | Cooling | Air Side Economizer | Biz-Custom | Office | Retro | 788 | 20% | 158 | 0.09 | 0.00 | 15 | $153 | 100% | 40% | 4 | 51% | 25% | 0.8 | 0.4 | 0.8 |
| 886 | Cooling | Advanced Rooftop Controls | Biz-Custom | Office | Retro | 6,782 | 56% | 3,785 | 2.15 | 0.02 | 15 | $2,950 | 100% | 40% | 5 | 51% | 20% | 0.8 | 0.5 | 1.0 |
| 887 | Cooling | HVAC Occupancy Controls | Biz-Custom | Office | Retro | 823 | 20% | 165 | 0.09 | 0.00 | 15 | $537 | 100% | 40% | 6 | 51% | 10% | 0.8 | 0.3 | 0.2 |
| 888 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Office | ROB | 816 | 13% | 102 | 0.06 | 0.00 | 15 | $115 | 100% | 40% | 7 | 7% | 10% | 0.8 | 0.4 | 0.7 |
| 889 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Office | ROB | 816 | 22% | 181 | 0.10 | 0.00 | 15 | $514 | 100% | 40% | 7 | 7% | 10% | 0.8 | 0.3 | 0.3 |
| 890 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Office | ROB | 816 | 33% | 272 | 0.15 | 0.00 | 15 | $631 | 100% | 40% | 7 | 7% | 10% | 0.8 | 0.3 | 0.3 |
| 891 | Cooling | Smart Thermostat | Biz-Prescriptive | Office | ROB | 3,264 | 14% | 462 | 0.26 | 0.00 | 11 | $175 | 100% | 40% | 8 | 7% | 10% | 0.8 | 0.6 | 1.6 |
| 892 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Office | ROB | 1,053 | 7% | 76 | 0.04 | 0.00 | 8 | $84 | 100% | 40% | 9 | 7% | 20% | 0.8 | 0.4 | 0.4 |
| 893 | Cooling | Air Cooled Chiller | Biz-Custom | Office | ROB | 834 | 9% | 75 | 0.04 | 0.00 | 23 | $126 | 100% | 40% | 10 | 32% | 10% | 0.8 | 0.3 | 0.7 |
| 894 | Cooling | Water Cooled Chiller | Biz-Custom | Office | ROB | 419 | 23% | 95 | 0.05 | 0.00 | 23 | $126 | 100% | 40% | 11 | 4% | 10% | 0.8 | 0.3 | 0.9 |
| 895 | Cooling | Window Film | Biz-Custom | Office | Retro | 6,000 | 4% | 264 | 0.15 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 896 | Cooling | Triple Pane Windows | Biz-Custom | Office | Retro | 6,000 | 6% | 360 | 0.20 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 897 | Cooling | Energy Recovery Ventilator | Biz-Custom | Office | Retro | 865 | 103% | 894 | 0.51 | 0.00 | 15 | $1,043 | 100% | 40% | 13 | 100% | 2% | 0.8 | 0.4 | 0.7 |
| 898 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Office | ROB | 1,962 | 4% | 74 | 0.01 | 0.02 | 15 | $135 | 100% | 40% | 1 | 6% | 10% | 0.8 | 0.3 | 0.4 |
| 899 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Office | ROB | 1,962 | 12% | 238 | 0.05 | 0.05 | 15 | $446 | 100% | 40% | 1 | 6% | 10% | 0.8 | 0.3 | 0.4 |
| 900 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Office | ROB | 1,962 | 18% | 362 | 0.07 | 0.08 | 15 | $520 | 100% | 40% | 1 | 6% | 10% | 0.8 | 0.3 | 0.5 |
| 901 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,187 | 6% | 136 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.0 |
| 902 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,187 | 12% | 252 | 0.05 | 0.06 | 15 | $171 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.1 |
| 903 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,265 | 7% | 151 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 3 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 904 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,265 | 12% | 274 | 0.05 | 0.06 | 15 | $182 | 100% | 40% | 3 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 905 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,379 | 7% | 168 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 4 | 16% | 10% | 0.8 | 0.5 | 1.3 |
| 906 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Office | ROB | 2,379 | 13% | 302 | 0.06 | 0.07 | 15 | $202 | 100% | 40% | 4 | 16% | 10% | 0.8 | 0.5 | 1.2 |
| 907 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Office | ROB | 1,565 | 4% | 56 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 4% | 20% | 0.8 | 0.4 | 0.6 |
| 908 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Office | ROB | 1,565 | 8% | 127 | 0.02 | 0.03 | 25 | $108 | 100% | 40% | 5 | 4% | 20% | 0.8 | 0.4 | 1.3 |
| 909 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Office | ROB | 2,388 | 9% | 215 | 0.04 | 0.05 | 8 | $84 | 100% | 40% | 6 | 10% | 20% | 0.8 | 0.6 | 1.2 |
| 910 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Office | ROB | 4,536 | 67% | 3,038 | 0.51 | 0.45 | 15 | $1,115 | 100% | 40% | 1 | 100% | 13% | 0.7 | 0.5 | 1.9 |
| 911 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Office | Retro | 4,536 | 2% | 91 | 0.02 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 1.3 |
| 912 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Office | ROB | 18,059 | 54% | 9,789 | 1.64 | 1.46 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 46.1 |
| 913 | HotWater | Faucet Aerator | Biz-Prescriptive | Office | Retro | 4,536 | 67% | 3,038 | 0.51 | 0.45 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 1.9 |
| 914 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Office | ROB | 1,868 | 20% | 380 | 0.06 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.1 |
| 915 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Office | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 916 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Office | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 917 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Office | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 918 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Office | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| 919 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Office | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 920 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Office | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 921 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Office | Retro | 179 | 68% | 121 | 0.02 | 0.02 | 15 | $27 | 100% | 40% | 1 | 3% | 75% | 0.8 | 0.8 | 3.2 |
| 922 | Lighting_Int | LED interior directional | Biz-Prescriptive | Office | Retro | 128 | 74% | 95 | 0.02 | 0.01 | 15 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.1 |
| 923 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Office | Retro | 115 | 45% | 51 | 0.01 | 0.01 | 15 | $2 | 100% | 40% | 3 | 80% | 45% | 0.8 | 0.7 | 19.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 924 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Office | Retro | 260 | 50% | 130 | 0.02 | 0.02 | 15 | $70 | 100% | 40% | 3 | 80% | 45% | 0.8 | 0.6 | 1.3 |
| 925 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Office | Retro | 516 | 61% | 314 | 0.05 | 0.05 | 15 | $44 | 100% | 40% | 4 | 9% | 35% | 0.8 | 0.7 | 5.0 |
| 926 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Office | Retro | 2,423 | 68% | 1,649 | 0.27 | 0.24 | 15 | $330 | 100% | 40% | 5 | 6% | 35% | 0.8 | 0.6 | 3.5 |
| 927 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Office | Retro | 96 | 100% | 96 | 0.02 | 0.01 | 11 | $4 | 100% | 40% | 6 | 80% | 0% | 0.8 | 0.7 | 13.2 |
| 928 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Office | Retro | 560 | 30% | 168 | 0.03 | 0.02 | 10 | $58 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.6 | 1.5 |
| 929 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Office | Retro | 2 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.5 | 1.2 |
| 930 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Office | Retro | 438 | 30% | 131 | 0.02 | 0.02 | 15 | $77 | 100% | 40% | 7 | 96% | 20% | 0.8 | 0.5 | 1.2 |
| 931 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Office | Retro | 70 | 43% | 30 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.3 |
| 932 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Office | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 933 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Office | Retro | 9,932 | 50% | 4,966 | 0.73 | 0.58 | 20 | $1,180 | 100% | 40% | 2 | 7% | 10% | 0.8 | 0.6 | 3.5 |
| 934 | Misc | High Efficiency Hand Dryers | Biz-Custom | Office | Retro | 262 | 83% | 217 | 0.03 | 0.03 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.3 | 0.2 |
| 935 | Misc | Ozone Commercial Laundry | Biz-Custom | Office | Retro | 2,984 | 25% | 746 | 0.11 | 0.09 | 10 | $20,310 | 100% | 40% | 4 | 1% | 2% | 0.8 | 0.2 | 1.2 |
| 936 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Office | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 937 | Misc | Miscellaneous Custom | Biz-Custom | Office | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 31% | 10% | 0.8 | 0.3 | 0.3 |
| 938 | Motors | Cogged V-Belt | Biz-Custom | Office | Retro | 9,092 | 3% | 282 | 0.04 | 0.04 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.3 | 0.5 |
| 939 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Office | Retro | 3,805 | 34% | 1,290 | 0.16 | 0.17 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 940 | Motors | Power Drive Systems | Biz-Custom | Office | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 941 | Motors | Switch Reluctance Motors | Biz-Custom | Office | Retro | 17,620 | 31% | 5,392 | 0.69 | 0.71 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 7.0 |
| 942 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Office | Retro | 551 | 40% | 223 | 0.03 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| 943 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Office | Retro | 1,086 | 10% | 109 | 0.02 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 944 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Office | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 945 | Office_PC | Energy Star Server | Biz-Custom | Office | ROB | 1,621 | 23% | 368 | 0.05 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.3 |
| 946 | Office_PC | Server Virtualization | Biz-Custom | Office | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 947 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Office | Retro | 86,783 | 18% | 15,778 | 2.31 | 1.83 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 22.2 |
| 948 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Office | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.8 |
| 949 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Office | Retro | 764 | 47% | 358 | 0.05 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 950 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Office | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 951 | Refrigeration | Strip Curtains | Biz-Prescriptive | Office | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 4 | $0 | 100% | 0% | 1 | 10% | 30% | 0.7 | 0.6 | 0.0 |
| 952 | Refrigeration | Bare Suction Line | Biz-Custom | Office | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 953 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Office | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 7% | 25% | 0.7 | 0.4 | 0.4 |
| 954 | Refrigeration | Saturated Suction Controls | Biz-Custom | Office | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 955 | Refrigeration | Compressor Retrofit | Biz-Custom | Office | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 22% | 25% | 0.7 | 0.4 | 0.2 |
| 956 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Office | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 6% | 80% | 0.9 | 0.8 | 3.5 |
| 957 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Office | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 6% | 25% | 0.7 | 0.5 | 3.1 |
| 958 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Office | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 8% | 25% | 0.7 | 0.4 | 0.8 |
| 959 | Refrigeration | Refrigeration Economizer | Biz-Custom | Office | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 31% | 10% | 0.7 | 0.4 | 0.8 |
| 960 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Office | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 20% | 25% | 0.7 | 0.5 | 2.1 |
| 961 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Office | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 6% | 25% | 0.7 | 0.4 | 0.5 |
| 962 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Office | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 3% | 80% | 0.9 | 0.8 | 3.5 |
| 963 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Office | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 3% | 2% | 0.7 | 0.4 | 0.8 |
| 964 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Office | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 19% | 54% | 0.7 | 0.6 | 0.3 |
| 965 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Office | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 19% | 54% | 0.7 | 0.6 | 0.1 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 966 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Office | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 7% | 25% | 0.7 | 0.6 | 7.3 |
| 967 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Office | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 7% | 25% | 0.7 | 0.5 | 1.2 |
| 968 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Office | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.4 |
| 969 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Office | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 6% | 54% | 0.7 | 0.6 | 0.1 |
| 970 | Refrigeration | Refrigeration - Custom | Biz-Custom | Office | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 971 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Office | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 972 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Office | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 9% | 44% | 0.7 | 0.6 | 1.6 |
| 973 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Office | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 9% | 30% | 0.7 | 0.4 | 0.2 |
| 974 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Office | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 12% | 35% | 0.7 | 0.5 | 3.4 |
| 975 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Office | Retro | 2,644 | 20% | 529 | 0.09 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 1.8 |
| 976 | Ventilation | Demand Control Ventilation | Biz-Custom | Office | Retro | 2,166 | 43% | 940 | 0.16 | 0.12 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.9 |
| 977 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Office | Retro | 19,919 | 82% | 16,287 | 2.82 | 2.08 | 15 | $4,130 | 100% | 40% | 3 | 5% | 32% | 0.8 | 0.6 | 2.8 |
| 978 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Office | Retro | 21,909 | 83% | 18,277 | 3.17 | 2.33 | 15 | $4,190 | 100% | 40% | 4 | 5% | 32% | 0.8 | 0.6 | 3.1 |
| 979 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Office | Retro | 23,903 | 82% | 19,579 | 3.39 | 2.50 | 15 | $4,230 | 100% | 40% | 5 | 5% | 32% | 0.8 | 0.6 | 3.3 |
| 980 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Office | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.8 |
| 981 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Office | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 982 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Office | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.9 |
| 983 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Office | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.5 |
| 984 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Office | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 1.0 |
| 985 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Warehouse | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 986 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Warehouse | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 987 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Warehouse | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 988 | CompressedAir | AODD Pump Controls | Biz-Custom | Warehouse | Retro | 103,919 | 35% | 36,372 | 4.91 | 3.96 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.3 |
| 989 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Warehouse | Retro | 103,919 | 2% | 2,320 | 0.31 | 0.25 | 13 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 2.0 |
| 990 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Warehouse | Retro | 1,480 | 50% | 740 | 0.10 | 0.08 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 10.0 |
| 991 | CompressedAir | Compressed Air - Custom | Biz-Custom | Warehouse | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 992 | Cooking | Commercial Griddles | Biz-Prescriptive | Warehouse | ROB | 15,825 | 12% | 1,910 | 0.47 | 0.20 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 993 | Cooking | Convection Ovens | Biz-Prescriptive | Warehouse | ROB | 9,839 | 11% | 1,065 | 0.26 | 0.11 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 994 | Cooking | Combination Ovens | Biz-Prescriptive | Warehouse | ROB | 23,958 | 38% | 9,058 | 2.21 | 0.96 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.3 |
| 995 | Cooking | Commercial Fryers | Biz-Prescriptive | Warehouse | ROB | 18,955 | 17% | 3,274 | 0.80 | 0.35 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 996 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Warehouse | ROB | 17,846 | 55% | 9,863 | 2.41 | 1.05 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 997 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Warehouse | ROB | 13,697 | 68% | 9,314 | 2.28 | 0.99 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.7 |
| 998 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Warehouse | ROB | 4,383 | 60% | 2,630 | 0.64 | 0.28 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.1 |
| 999 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Warehouse | ROB | 39,306 | 44% | 17,369 | 2.34 | 2.62 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.2 |
| 1000 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Warehouse | ROB | 26,901 | 32% | 8,586 | 1.16 | 1.29 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.0 |
| 1001 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Warehouse | ROB | 365 | 15% | 54 | 0.03 | 0.00 | 15 | $153 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.3 |
| 1002 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Warehouse | ROB | 365 | 19% | 71 | 0.05 | 0.00 | 15 | $215 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.3 |
| 1003 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Warehouse | ROB | 365 | 31% | 113 | 0.07 | 0.00 | 15 | $399 | 100% | 40% | 1 | 31% | 10% | 0.8 | 0.3 | 0.2 |
| 1004 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Warehouse | ROB | 401 | 8% | 31 | 0.02 | 0.00 | 15 | $59 | 100% | 40% | 2 | 31% | 10% | 0.8 | 0.3 | 0.4 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1005** | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Warehouse | ROB | 401 | 12% | 48 | 0.03 | 0.00 | 15 | $97 | 100% | 40% | 2 | 31% | 10% | 0.8 | 0.3 | 0.4 |
| **1006** | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Warehouse | ROB | 401 | 22% | 90 | 0.06 | 0.00 | 15 | $204 | 100% | 40% | 2 | 31% | 10% | 0.8 | 0.3 | 0.4 |
| **1007** | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Warehouse | Retro | 441 | 7% | 31 | 0.02 | 0.00 | 3 | $5 | 100% | 40% | 3 | 62% | 50% | 0.8 | 0.6 | 1.2 |
| **1008** | Cooling | Air Side Economizer | Biz-Custom | Warehouse | Retro | 365 | 20% | 73 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 4 | 62% | 25% | 0.8 | 0.4 | 0.4 |
| **1009** | Cooling | Advanced Rooftop Controls | Biz-Custom | Warehouse | Retro | 6,263 | 56% | 3,495 | 2.28 | 0.00 | 15 | $2,950 | 100% | 40% | 5 | 62% | 20% | 0.8 | 0.4 | 1.0 |
| **1010** | Cooling | HVAC Occupancy Controls | Biz-Custom | Warehouse | Retro | 381 | 20% | 76 | 0.05 | 0.00 | 15 | $537 | 100% | 40% | 6 | 62% | 10% | 0.8 | 0.2 | 0.1 |
| **1011** | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 378 | 13% | 47 | 0.03 | 0.00 | 15 | $115 | 100% | 40% | 7 | 38% | 10% | 0.8 | 0.3 | 0.3 |
| **1012** | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 378 | 22% | 84 | 0.05 | 0.00 | 15 | $514 | 100% | 40% | 7 | 38% | 10% | 0.8 | 0.2 | 0.1 |
| **1013** | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 378 | 33% | 126 | 0.08 | 0.00 | 15 | $631 | 100% | 40% | 7 | 38% | 10% | 0.8 | 0.2 | 0.2 |
| **1014** | Cooling | Smart Thermostat | Biz-Prescriptive | Warehouse | ROB | 1,512 | 14% | 214 | 0.14 | 0.00 | 11 | $175 | 100% | 40% | 8 | 38% | 10% | 0.8 | 0.4 | 0.8 |
| **1015** | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Warehouse | ROB | 488 | 7% | 35 | 0.02 | 0.00 | 8 | $84 | 100% | 40% | 9 | 0% | 20% | 0.8 | 0.4 | 0.2 |
| **1016** | Cooling | Air Cooled Chiller | Biz-Custom | Warehouse | ROB | 386 | 9% | 35 | 0.02 | 0.00 | 23 | $126 | 100% | 40% | 10 | 0% | 10% | 0.8 | 0.3 | 0.3 |
| **1017** | Cooling | Water Cooled Chiller | Biz-Custom | Warehouse | ROB | 194 | 23% | 44 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 11 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| **1018** | Cooling | Window Film | Biz-Custom | Warehouse | Retro | 6,000 | 4% | 264 | 0.17 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.6 |
| **1019** | Cooling | Triple Pane Windows | Biz-Custom | Warehouse | Retro | 6,000 | 6% | 360 | 0.23 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| **1020** | Cooling | Energy Recovery Ventilator | Biz-Custom | Warehouse | Retro | 401 | 0% | 0 | 0.00 | 0.00 | 15 | $1,042 | 100% | | 13 | 100% | 2% | 0.8 | 0.7 | 0.0 |
| **1021** | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 1,755 | 3% | 53 | 0.01 | 0.01 | 15 | $135 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.3 |
| **1022** | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 1,755 | 11% | 189 | 0.04 | 0.04 | 15 | $446 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.3 |
| **1023** | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Warehouse | ROB | 1,755 | 15% | 269 | 0.06 | 0.06 | 15 | $520 | 100% | 40% | 1 | 13% | 10% | 0.8 | 0.3 | 0.4 |
| **1024** | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 1,975 | 6% | 117 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 2 | 7% | 10% | 0.8 | 0.4 | 0.9 |
| **1025** | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 1,975 | 11% | 218 | 0.05 | 0.05 | 15 | $171 | 100% | 40% | 2 | 7% | 10% | 0.8 | 0.4 | 1.0 |
| **1026** | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 2,041 | 6% | 127 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 3 | 7% | 10% | 0.8 | 0.4 | 1.0 |
| **1027** | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 2,041 | 11% | 234 | 0.05 | 0.05 | 15 | $182 | 100% | 40% | 3 | 7% | 10% | 0.8 | 0.5 | 1.0 |
| **1028** | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 2,125 | 6% | 138 | 0.03 | 0.03 | 15 | $100 | 100% | 40% | 4 | 7% | 10% | 0.8 | 0.5 | 1.1 |
| **1029** | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Warehouse | ROB | 2,125 | 12% | 254 | 0.06 | 0.06 | 15 | $202 | 100% | 40% | 4 | 7% | 10% | 0.8 | 0.4 | 1.0 |
| **1030** | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Warehouse | ROB | 1,331 | 3% | 43 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.4 | 0.4 |
| **1031** | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Warehouse | ROB | 1,331 | 6% | 75 | 0.02 | 0.02 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.4 | 0.8 |
| **1032** | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Warehouse | ROB | 2,144 | 5% | 114 | 0.02 | 0.03 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.5 | 0.6 |
| **1033** | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Warehouse | ROB | 3,027 | 67% | 2,027 | 0.27 | 0.31 | 15 | $1,115 | 100% | 40% | 1 | 100% | 0% | 0.7 | 0.5 | 1.3 |
| **1034** | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Warehouse | Retro | 3,027 | 2% | 61 | 0.01 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 0.9 |
| **1035** | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Warehouse | ROB | 18,059 | 54% | 9,789 | 1.32 | 1.48 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 45.1 |
| **1036** | HotWater | Faucet Aerator | Biz-Prescriptive | Warehouse | Retro | 3,027 | 67% | 2,027 | 0.27 | 0.31 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 1.3 |
| **1037** | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Warehouse | ROB | 1,868 | 20% | 380 | 0.05 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| **1038** | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Warehouse | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| **1039** | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Warehouse | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| **1040** | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Warehouse | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| **1041** | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Warehouse | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.14 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |
| **1042** | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Warehouse | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| **1043** | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Warehouse | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1044 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Warehouse | Retro | 170 | 68% | 115 | 0.02 | 0.01 | 15 | $27 | 100% | 40% | 1 | 4% | 75% | 0.8 | 0.8 | 2.9 |
| 1045 | Lighting_Int | LED interior directional | Biz-Prescriptive | Warehouse | Retro | 122 | 74% | 90 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.0 |
| 1046 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Warehouse | Retro | 110 | 45% | 49 | 0.01 | 0.01 | 15 | $2 | 100% | 40% | 3 | 76% | 45% | 0.8 | 0.7 | 17.6 |
| 1047 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Warehouse | Retro | 248 | 50% | 124 | 0.02 | 0.01 | 15 | $70 | 100% | 40% | 3 | 76% | 45% | 0.8 | 0.6 | 1.2 |
| 1048 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Warehouse | Retro | 492 | 61% | 299 | 0.04 | 0.03 | 15 | $44 | 100% | 40% | 4 | 11% | 35% | 0.8 | 0.7 | 4.6 |
| 1049 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Warehouse | Retro | 2,310 | 68% | 1,571 | 0.22 | 0.17 | 15 | $330 | 100% | 40% | 5 | 7% | 35% | 0.8 | 0.6 | 3.2 |
| 1050 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Warehouse | Retro | 91 | 100% | 91 | 0.01 | 0.01 | 11 | $4 | 100% | 40% | 6 | 76% | 0% | 0.8 | 0.7 | 12.0 |
| 1051 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Warehouse | Retro | 534 | 30% | 160 | 0.02 | 0.02 | 10 | $58 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.6 | 1.4 |
| 1052 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Warehouse | Retro | 2 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.5 | 1.1 |
| 1053 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Warehouse | Retro | 417 | 30% | 125 | 0.02 | 0.01 | 15 | $74 | 100% | 40% | 7 | 95% | 20% | 0.8 | 0.5 | 1.1 |
| 1054 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Warehouse | Retro | 63 | 43% | 27 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 1055 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Warehouse | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 1056 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Warehouse | Retro | 9,932 | 50% | 4,966 | 0.67 | 0.54 | 20 | $1,180 | 100% | 40% | 2 | 0% | 10% | 0.8 | 0.6 | 3.5 |
| 1057 | Misc | High Efficiency Hand Dryers | Biz-Custom | Warehouse | Retro | 262 | 83% | 217 | 0.03 | 0.02 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.3 | 0.2 |
| 1058 | Misc | Ozone Commercial Laundry | Biz-Custom | Warehouse | Retro | 2,984 | 25% | 746 | 0.10 | 0.08 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 1059 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Warehouse | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 1060 | Misc | Miscellaneous Custom | Biz-Custom | Warehouse | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 65% | 10% | 0.8 | 0.3 | 0.3 |
| 1061 | Motors | Cogged V-Belt | Biz-Custom | Warehouse | Retro | 20,965 | 3% | 650 | 0.10 | 0.10 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.2 |
| 1062 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Warehouse | Retro | 3,805 | 34% | 1,290 | 0.19 | 0.20 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |
| 1063 | Motors | Power Drive Systems | Biz-Custom | Warehouse | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.4 |
| 1064 | Motors | Switch Reluctance Motors | Biz-Custom | Warehouse | Retro | 40,630 | 31% | 12,433 | 1.86 | 1.91 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.7 | 16.5 |
| 1065 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Warehouse | Retro | 551 | 40% | 223 | 0.03 | 0.02 | 6 | $0 | 100% | | 1 | 5% | 90% | 0.9 | 0.9 | 0.0 |
| 1066 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Warehouse | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 1067 | Office_NonPC | Plug Load  Occupancy Sensor | Biz-Custom | Warehouse | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 1068 | Office_PC | Energy Star Server | Biz-Custom | Warehouse | ROB | 1,621 | 23% | 368 | 0.05 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.3 |
| 1069 | Office_PC | Server Virtualization | Biz-Custom | Warehouse | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 1070 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Warehouse | Retro | 86,783 | 18% | 15,778 | 2.13 | 1.72 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 22.1 |
| 1071 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Warehouse | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 1072 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Warehouse | Retro | 764 | 47% | 358 | 0.05 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 1073 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Warehouse | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 1074 | Refrigeration | Strip Curtains | Biz-Prescriptive | Warehouse | Retro | 207 | 50% | 103 | 0.01 | 0.01 | 4 | $10 | 100% | 40% | 1 | 13% | 30% | 0.7 | 0.6 | 2.2 |
| 1075 | Refrigeration | Bare Suction Line | Biz-Custom | Warehouse | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 1076 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Warehouse | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 9% | 25% | 0.7 | 0.4 | 0.4 |
| 1077 | Refrigeration | Saturated Suction Controls | Biz-Custom | Warehouse | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 1078 | Refrigeration | Compressor Retrofit | Biz-Custom | Warehouse | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 29% | 25% | 0.7 | 0.4 | 0.2 |
| 1079 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Warehouse | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 8% | 80% | 0.9 | 0.8 | 3.5 |
| 1080 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Warehouse | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 8% | 25% | 0.7 | 0.5 | 3.1 |
| 1081 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Warehouse | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 11% | 25% | 0.7 | 0.4 | 0.8 |
| 1082 | Refrigeration | Refrigeration Economizer | Biz-Custom | Warehouse | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 41% | 10% | 0.7 | 0.4 | 0.8 |
| 1083 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Warehouse | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 9% | 25% | 0.7 | 0.5 | 2.1 |
| 1084 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Warehouse | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 3% | 25% | 0.7 | 0.4 | 0.5 |
| 1085 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Warehouse | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 1% | 80% | 0.9 | 0.8 | 3.5 |
| 1086 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Warehouse | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 1% | 2% | 0.7 | 0.4 | 0.8 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1087 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Warehouse | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 9% | 54% | 0.7 | 0.6 | 0.3 |
| 1088 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Warehouse | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 9% | 54% | 0.7 | 0.6 | 0.1 |
| 1089 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Warehouse | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 3% | 25% | 0.7 | 0.6 | 7.3 |
| 1090 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Warehouse | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 3% | 25% | 0.7 | 0.5 | 1.2 |
| 1091 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Warehouse | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 3% | 54% | 0.7 | 0.6 | 0.4 |
| 1092 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Warehouse | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 3% | 54% | 0.7 | 0.6 | 0.1 |
| 1093 | Refrigeration | Refrigeration - Custom | Biz-Custom | Warehouse | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 1094 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Warehouse | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 1095 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Warehouse | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 0% | 44% | 0.7 | 0.6 | 1.6 |
| 1096 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Warehouse | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 9% | 30% | 0.7 | 0.4 | 0.2 |
| 1097 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Warehouse | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 6% | 35% | 0.7 | 0.5 | 3.4 |
| 1098 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Warehouse | Retro | 2,298 | 20% | 460 | 0.05 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.4 |
| 1099 | Ventilation | Demand Control Ventilation | Biz-Custom | Warehouse | Retro | 2,166 | 43% | 940 | 0.11 | 0.13 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.8 |
| 1100 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Warehouse | Retro | 19,919 | 82% | 16,287 | 1.83 | 2.34 | 15 | $4,130 | 100% | 40% | 3 | 10% | 32% | 0.8 | 0.6 | 2.7 |
| 1101 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Warehouse | Retro | 21,909 | 83% | 18,277 | 2.05 | 2.62 | 15 | $4,190 | 100% | 40% | 4 | 10% | 32% | 0.8 | 0.6 | 3.0 |
| 1102 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Warehouse | Retro | 23,903 | 82% | 19,579 | 2.20 | 2.81 | 15 | $4,230 | 100% | 40% | 5 | 10% | 32% | 0.8 | 0.6 | 3.1 |
| 1103 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Warehouse | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 1104 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Warehouse | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% | | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 1105 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Warehouse | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.6 |
| 1106 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Warehouse | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 1107 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Warehouse | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 0.9 |
| 1108 | CompressedAir | Compressed Air Leak Repair | Biz-Custom | Other | Retro | 6 | 17% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 39% | 0.8 | 0.6 | 3.3 |
| 1109 | CompressedAir | Retro-commissioning_Compressed Air Optimization | Biz-Custom RCx | Other | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 1 | 100% | 20% | 0.8 | 0.6 | 1.2 |
| 1110 | CompressedAir | Efficient Air Compressors (VSD) | Biz-Custom | Other | ROB | 1,583 | 21% | 329 | 0.04 | 0.04 | 13 | $127 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.6 | 1.5 |
| 1111 | CompressedAir | AODD Pump Controls | Biz-Custom | Other | Retro | 103,919 | 35% | 36,372 | 4.38 | 4.31 | 10 | $1,150 | 100% | 40% | 3 | 100% | 50% | 0.8 | 0.7 | 15.2 |
| 1112 | CompressedAir | No Loss Condensate Drain | Biz-Custom | Other | Retro | 103,919 | 2% | 2,320 | 0.28 | 0.27 | 10 | $700 | 100% | 40% | 4 | 100% | 5% | 0.8 | 0.6 | 1.6 |
| 1113 | CompressedAir | Efficient Air Nozzles | Biz-Custom | Other | Retro | 1,480 | 50% | 740 | 0.09 | 0.09 | 15 | $50 | 100% | 40% | 5 | 5% | 20% | 0.8 | 0.6 | 9.9 |
| 1114 | CompressedAir | Compressed Air - Custom | Biz-Custom | Other | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 100% | 20% | 0.8 | 0.6 | 2.3 |
| 1115 | Cooking | Commercial Griddles | Biz-Prescriptive | Other | ROB | 15,825 | 12% | 1,910 | 0.32 | 0.24 | 12 | $0 | 100% | | 1 | 14% | 17% | 0.7 | 0.6 | 0.0 |
| 1116 | Cooking | Convection Ovens | Biz-Prescriptive | Other | ROB | 9,839 | 11% | 1,065 | 0.18 | 0.14 | 12 | $0 | 100% | | 2 | 18% | 53% | 0.7 | 0.6 | 0.0 |
| 1117 | Cooking | Combination Ovens | Biz-Prescriptive | Other | ROB | 23,958 | 38% | 9,058 | 1.53 | 1.16 | 12 | $4,300 | 100% | 40% | 2 | 18% | 53% | 0.7 | 0.6 | 1.2 |
| 1118 | Cooking | Commercial Fryers | Biz-Prescriptive | Other | ROB | 18,955 | 17% | 3,274 | 0.55 | 0.42 | 12 | $1,500 | 100% | 40% | 3 | 27% | 24% | 0.7 | 0.5 | 1.3 |
| 1119 | Cooking | Commercial Steam Cookers | Biz-Prescriptive | Other | ROB | 17,846 | 55% | 9,863 | 1.67 | 1.26 | 12 | $4,150 | 100% | 40% | 4 | 6% | 45% | 0.7 | 0.6 | 1.4 |
| 1120 | Cooking | Insulated Holding Cabinets (Full Size) | Biz-Prescriptive | Other | ROB | 13,697 | 68% | 9,314 | 1.57 | 1.19 | 12 | $1,200 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.5 | 4.5 |
| 1121 | Cooking | Insulated Holding Cabinets (Half-Size) | Biz-Prescriptive | Other | ROB | 4,383 | 60% | 2,630 | 0.44 | 0.34 | 12 | $1,500 | 100% | 40% | 5 | 3% | 16% | 0.7 | 0.4 | 1.0 |
| 1122 | Cooking | Dishwasher Low Temp Door (Energy Star) | Biz-Prescriptive | Other | ROB | 39,306 | 44% | 17,369 | 2.34 | 2.62 | 15 | $662 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 18.2 |
| 1123 | Cooking | Dishwasher High Temp Door (Energy Star) | Biz-Prescriptive | Other | ROB | 26,901 | 32% | 8,586 | 1.16 | 1.29 | 15 | $995 | 100% | 40% | 6 | 26% | 61% | 0.7 | 0.7 | 6.0 |
| 1124 | Cooling | Air Conditioner - 17 IEER (5-20 Tons) | Biz-Prescriptive | Other | ROB | 660 | 15% | 97 | 0.05 | 0.00 | 15 | $153 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.5 |
| 1125 | Cooling | Air Conditioner - 18 IEER (5-20 Tons) | Biz-Prescriptive | Other | ROB | 660 | 19% | 128 | 0.06 | 0.00 | 15 | $215 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.5 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1126 | Cooling | Air Conditioner - 21 IEER (5-20 Tons) | Biz-Prescriptive | Other | ROB | 660 | 31% | 204 | 0.10 | 0.00 | 15 | $399 | 100% | 40% | 1 | 29% | 10% | 0.8 | 0.3 | 0.4 |
| 1127 | Cooling | Air Conditioner - 14.3 IEER (20+ Tons) | Biz-Prescriptive | Other | ROB | 725 | 8% | 56 | 0.03 | 0.00 | 15 | $59 | 100% | 40% | 2 | 29% | 10% | 0.8 | 0.4 | 0.7 |
| 1128 | Cooling | Air Conditioner - 15 IEER (20+ Tons) | Biz-Prescriptive | Other | ROB | 725 | 12% | 87 | 0.04 | 0.00 | 15 | $97 | 100% | 40% | 2 | 29% | 10% | 0.8 | 0.4 | 0.7 |
| 1129 | Cooling | Air Conditioner - 17 IEER (20+ Tons) | Biz-Prescriptive | Other | ROB | 725 | 22% | 162 | 0.08 | 0.00 | 15 | $204 | 100% | 40% | 2 | 29% | 10% | 0.8 | 0.3 | 0.6 |
| 1130 | Cooling | Comprehensive Rooftop Unit Quality Maintenance (AC Tune-up) | Biz-Custom | Other | Retro | 797 | 7% | 56 | 0.03 | 0.00 | 3 | $5 | 100% | 40% | 3 | 57% | 50% | 0.8 | 0.6 | 2.0 |
| 1131 | Cooling | Air Side Economizer | Biz-Custom | Other | Retro | 660 | 20% | 132 | 0.06 | 0.00 | 15 | $153 | 100% | 40% | 4 | 57% | 25% | 0.8 | 0.4 | 0.7 |
| 1132 | Cooling | Advanced Rooftop Controls | Biz-Custom | Other | Retro | 6,773 | 56% | 3,779 | 1.76 | 0.04 | 15 | $2,950 | 100% | 40% | 5 | 57% | 20% | 0.8 | 0.5 | 1.0 |
| 1133 | Cooling | HVAC Occupancy Controls | Biz-Custom | Other | Retro | 689 | 20% | 138 | 0.06 | 0.00 | 15 | $537 | 100% | 40% | 6 | 57% | 10% | 0.8 | 0.3 | 0.2 |
| 1134 | Cooling | Air Conditioner - 16 SEER (<5 Tons) | Biz-Prescriptive | Other | ROB | 683 | 13% | 85 | 0.04 | 0.00 | 15 | $115 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.6 |
| 1135 | Cooling | Air Conditioner - 18 SEER(<5 Tons) | Biz-Prescriptive | Other | ROB | 683 | 22% | 152 | 0.07 | 0.00 | 15 | $514 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.2 |
| 1136 | Cooling | Air Conditioner - 21 SEER(<5 Tons) | Biz-Prescriptive | Other | ROB | 683 | 33% | 228 | 0.11 | 0.00 | 15 | $631 | 100% | 40% | 7 | 0% | 10% | 0.8 | 0.3 | 0.3 |
| 1137 | Cooling | Smart Thermostat | Biz-Prescriptive | Other | ROB | 2,733 | 14% | 387 | 0.18 | 0.00 | 11 | $175 | 100% | 40% | 8 | 0% | 10% | 0.8 | 0.5 | 1.3 |
| 1138 | Cooling | PTAC - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Other | ROB | 881 | 7% | 64 | 0.03 | 0.00 | 8 | $84 | 100% | 40% | 9 | 0% | 20% | 0.8 | 0.4 | 0.3 |
| 1139 | Cooling | Air Cooled Chiller | Biz-Custom | Other | ROB | 698 | 9% | 63 | 0.03 | 0.00 | 23 | $126 | 100% | 40% | 10 | 38% | 10% | 0.8 | 0.3 | 0.5 |
| 1140 | Cooling | Water Cooled Chiller | Biz-Custom | Other | ROB | 351 | 23% | 80 | 0.04 | 0.00 | 23 | $126 | 100% | 40% | 11 | 4% | 10% | 0.8 | 0.3 | 0.7 |
| 1141 | Cooling | Window Film | Biz-Custom | Other | Retro | 6,000 | 4% | 264 | 0.12 | 0.00 | 10 | $154 | 100% | 40% | 12 | 100% | 25% | 0.8 | 0.5 | 0.5 |
| 1142 | Cooling | Triple Pane Windows | Biz-Custom | Other | Retro | 6,000 | 6% | 360 | 0.17 | 0.00 | 25 | $700 | 100% | 40% | 12 | 100% | 2% | 0.8 | 0.3 | 0.6 |
| 1143 | Cooling | Energy Recovery Ventilator | Biz-Custom | Other | Retro | 725 | 0% | 0 | 0.00 | 0.00 | 15 | $1,041 | 100% | | 13 | 100% | 2% | 0.8 | 0.7 | 0.0 |
| 1144 | Heating | Heat Pump - 16 SEER (<5 Tons) | Biz-Prescriptive | Other | ROB | 2,224 | 3% | 75 | 0.01 | 0.02 | 15 | $135 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 1145 | Heating | Heat Pump - 18 SEER(<5 Tons) | Biz-Prescriptive | Other | ROB | 2,224 | 11% | 253 | 0.04 | 0.06 | 15 | $446 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.4 |
| 1146 | Heating | Heat Pump - 21 SEER(<5 Tons) | Biz-Prescriptive | Other | ROB | 2,224 | 17% | 372 | 0.06 | 0.08 | 15 | $520 | 100% | 40% | 1 | 0% | 10% | 0.8 | 0.3 | 0.5 |
| 1147 | Heating | Heat Pump - 15.0 IEER COP 3.6 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,492 | 6% | 151 | 0.02 | 0.03 | 15 | $100 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.1 |
| 1148 | Heating | Heat Pump - 16.0 IEER COP 3.8 (65,000-134,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,492 | 11% | 280 | 0.04 | 0.06 | 15 | $171 | 100% | 40% | 2 | 17% | 10% | 0.8 | 0.5 | 1.2 |
| 1149 | Heating | Heat Pump - 14.5 IEER COP 3.5 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,578 | 6% | 166 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 3 | 17% | 10% | 0.8 | 0.5 | 1.2 |
| 1150 | Heating | Heat Pump - 15.5 IEER COP 3.7 (135,000-239,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,578 | 12% | 303 | 0.05 | 0.07 | 15 | $182 | 100% | 40% | 3 | 17% | 10% | 0.8 | 0.5 | 1.2 |
| 1151 | Heating | Heat Pump - 12 IEER 3.4 COP (>239,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,694 | 7% | 182 | 0.03 | 0.04 | 15 | $100 | 100% | 40% | 4 | 17% | 10% | 0.8 | 0.5 | 1.4 |
| 1152 | Heating | Heat Pump - 13 IEER 3.6 COP (>239,000 Btu/hr) | Biz-Prescriptive | Other | ROB | 2,694 | 12% | 331 | 0.05 | 0.07 | 25 | $202 | 100% | 40% | 4 | 17% | 10% | 0.8 | 0.5 | 1.8 |
| 1153 | Heating | Geothermal HP - 17 EER < 135kbtu | Biz-Prescriptive | Other | ROB | 1,726 | 3% | 58 | 0.01 | 0.01 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.4 | 0.6 |
| 1154 | Heating | Geothermal HP - 19 EER < 135kbtu | Biz-Prescriptive | Other | ROB | 1,726 | 7% | 118 | 0.02 | 0.03 | 25 | $108 | 100% | 40% | 5 | 0% | 20% | 0.8 | 0.4 | 1.2 |
| 1155 | Heating | PTHP - 7,000 to 15,000 Btuh - lodging | Biz-Prescriptive | Other | ROB | 2,712 | 7% | 190 | 0.03 | 0.04 | 8 | $84 | 100% | 40% | 6 | 0% | 20% | 0.8 | 0.5 | 1.0 |
| 1156 | HotWater | Heat Pump Water Heater | Biz-Prescriptive | Other | ROB | 3,027 | 67% | 2,027 | 0.27 | 0.31 | 15 | $1,115 | 100% | 40% | 1 | 100% | 20% | 0.7 | 0.5 | 1.3 |
| 1157 | HotWater | Hot Water Pipe Insulation | Biz-Prescriptive | Other | Retro | 3,027 | 2% | 61 | 0.01 | 0.01 | 20 | $60 | 100% | 40% | 2 | 100% | 80% | 0.9 | 0.8 | 0.9 |
| 1158 | HotWater | Low Flow Pre-Rinse Sprayers | Biz-Prescriptive | Other | ROB | 18,059 | 54% | 9,789 | 1.32 | 1.48 | 5 | $60 | 100% | 40% | 3 | 20% | 85% | 0.9 | 0.9 | 45.1 |
| 1159 | HotWater | Faucet Aerator | Biz-Prescriptive | Other | Retro | 3,027 | 67% | 2,027 | 0.27 | 0.31 | 15 | $1,115 | 100% | 40% | 4 | 20% | 85% | 0.9 | 0.9 | 1.3 |
| 1160 | HotWater | ENERGY STAR Commercial Washing Machines | Biz-Prescriptive | Other | ROB | 1,868 | 20% | 380 | 0.05 | 0.06 | 11 | $200 | 100% | 40% | 5 | 25% | 33% | 0.7 | 0.5 | 1.0 |
| 1161 | Lighting_Ext | LED wallpack (existing W<250) | Biz-Prescriptive | Other | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 1 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 1162 | Lighting_Ext | LED parking lot fixture (existing W<250) | Biz-Prescriptive | Other | Retro | 856 | 66% | 567 | 0.00 | 0.07 | 12 | $248 | 100% | 40% | 2 | 17% | 69% | 0.8 | 0.8 | 1.2 |
| 1163 | Lighting_Ext | LED parking lot fixture (existing W≥250) | Biz-Prescriptive | Other | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 3 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 1164 | Lighting_Ext | LED parking garage fixture (existing W<250) | Biz-Prescriptive | Other | Retro | 1,742 | 66% | 1,154 | 0.00 | 0.13 | 6 | $248 | 100% | 40% | 4 | 17% | 69% | 0.8 | 0.8 | 1.3 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below: **Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1165 | Lighting_Ext | LED parking garage fixture (existing W≥250) | Biz-Prescriptive | Other | Retro | 3,235 | 60% | 1,953 | 0.00 | 0.23 | 6 | $756 | 100% | 40% | 5 | 17% | 69% | 0.8 | 0.8 | 0.7 |
| 1166 | Lighting_Ext | LED outdoor pole decorative fixture (existing W≥250) | Biz-Prescriptive | Other | Retro | 1,589 | 60% | 959 | 0.00 | 0.11 | 12 | $756 | 100% | 40% | 6 | 17% | 69% | 0.8 | 0.8 | 0.6 |
| 1167 | Lighting_Int | LED downlight fixture | Biz-Prescriptive | Other | Retro | 194 | 68% | 131 | 0.02 | 0.02 | 15 | $27 | 100% | 40% | 1 | 2% | 75% | 0.8 | 0.8 | 3.3 |
| 1168 | Lighting_Int | LED interior directional | Biz-Prescriptive | Other | Retro | 140 | 74% | 103 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 2 | 0% | 75% | 0.8 | 0.8 | 1.2 |
| 1169 | Lighting_Int | LED T8 tube replacement | Biz-Prescriptive | Other | Retro | 125 | 45% | 56 | 0.01 | 0.01 | 15 | $2 | 100% | 40% | 3 | 86% | 45% | 0.8 | 0.7 | 20.1 |
| 1170 | Lighting_Int | LED troffer, 2'X2' and 2'X4' | Biz-Prescriptive | Other | Retro | 283 | 50% | 142 | 0.02 | 0.02 | 15 | $70 | 100% | 40% | 3 | 86% | 45% | 0.8 | 0.6 | 1.4 |
| 1171 | Lighting_Int | LED low bay fixture | Biz-Prescriptive | Other | Retro | 561 | 61% | 341 | 0.04 | 0.04 | 15 | $44 | 100% | 40% | 6 | 6% | 35% | 0.8 | 0.7 | 5.2 |
| 1172 | Lighting_Int | LED high bay fixture | Biz-Prescriptive | Other | Retro | 2,636 | 68% | 1,793 | 0.22 | 0.23 | 15 | $330 | 100% | 40% | 5 | 4% | 35% | 0.8 | 0.7 | 3.7 |
| 1173 | Lighting_Int | DeLamp Fluorescent Fixture Average Lamp Wattage 28W | Biz-Prescriptive | Other | Retro | 104 | 100% | 104 | 0.01 | 0.01 | 11 | $4 | 100% | 40% | 6 | 86% | 0% | 0.8 | 0.7 | 13.7 |
| 1174 | Lighting_Int | Daylighting Controls | Biz-Prescriptive | Other | Retro | 609 | 30% | 183 | 0.02 | 0.02 | 10 | $58 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.6 | 1.6 |
| 1175 | Lighting_Int | Network Lighting Controls - Wireless (WiFi) | Biz-Prescriptive | Other | Retro | 2 | 49% | 1 | 0.00 | 0.00 | 15 | $1 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.5 | 1.2 |
| 1176 | Lighting_Int | Occupancy Sensors | Biz-Prescriptive | Other | Retro | 476 | 30% | 143 | 0.02 | 0.02 | 15 | $84 | 100% | 40% | 7 | 97% | 20% | 0.8 | 0.5 | 1.1 |
| 1177 | Lighting_Int | LED Exit Sign - 4 Watt Fixture (2 lamp) | Biz-Prescriptive | Other | Retro | 66 | 43% | 28 | 0.00 | 0.00 | 5 | $33 | 100% | 40% | 8 | 1% | 80% | 0.9 | 0.8 | 0.2 |
| 1178 | Misc | Vending Machine Controller - Non-Refrigerated | Biz-Custom | Other | Retro | 385 | 61% | 237 | 0.03 | 0.03 | 5 | $230 | 100% | 40% | 1 | 5% | 30% | 0.8 | 0.4 | 0.3 |
| 1179 | Misc | Kitchen Exhaust Hood Demand Ventilation Control System | Biz-Custom | Other | Retro | 9,932 | 50% | 4,966 | 0.60 | 0.59 | 20 | $1,180 | 100% | 40% | 2 | 11% | 10% | 0.8 | 0.6 | 3.5 |
| 1180 | Misc | High Efficiency Hand Dryers | Biz-Custom | Other | Retro | 262 | 83% | 217 | 0.03 | 0.03 | 10 | $483 | 100% | 40% | 3 | 5% | 10% | 0.8 | 0.3 | 0.2 |
| 1181 | Misc | Ozone Commercial Laundry | Biz-Custom | Other | Retro | 2,984 | 25% | 746 | 0.09 | 0.09 | 10 | $20,310 | 100% | 40% | 4 | 0% | 2% | 0.8 | 0.2 | 1.2 |
| 1182 | Misc | ENERGY STAR Uninterrupted Power Supply | Biz-Custom | Other | ROB | 3,096 | 3% | 85 | 0.01 | 0.01 | 15 | $59 | 100% | 40% | 5 | 0% | 70% | 0.8 | 0.8 | 1.0 |
| 1183 | Misc | Miscellaneous Custom | Biz-Custom | Other | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 6 | 19% | 10% | 0.8 | 0.3 | 0.3 |
| 1184 | Motors | Cogged V-Belt | Biz-Custom | Other | Retro | 17,237 | 3% | 534 | 0.08 | 0.07 | 15 | $384 | 100% | 40% | 1 | 50% | 10% | 0.8 | 0.5 | 1.0 |
| 1185 | Motors | Pump and Fan Variable Frequency Drive Controls (Pumps) | Biz-Custom | Other | Retro | 3,805 | 34% | 1,290 | 0.19 | 0.16 | 15 | $168 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 1186 | Motors | Power Drive Systems | Biz-Custom | Other | Retro | 4 | 23% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 2 | 100% | 10% | 0.8 | 0.6 | 5.2 |
| 1187 | Motors | Switch Reluctance Motors | Biz-Custom | Other | Retro | 33,406 | 31% | 10,222 | 1.48 | 1.26 | 15 | $528 | 100% | 40% | 2 | 100% | 1% | 0.8 | 0.6 | 13.2 |
| 1188 | Office_NonPC | Energy Star Printer/Copier/Fax | Biz-Custom | Other | Retro | 551 | 40% | 223 | 0.03 | 0.03 | 6 | $0 | 100% | | 1 | 30% | 90% | 0.9 | 0.9 | 0.0 |
| 1189 | Office_NonPC | Smart Power Strip – Commercial Use | Biz-Custom | Other | Retro | 1,086 | 10% | 109 | 0.01 | 0.01 | 7 | $50 | 100% | 40% | 2 | 60% | 35% | 0.8 | 0.6 | 0.8 |
| 1190 | Office_NonPC | Plug Load Occupancy Sensor | Biz-Custom | Other | Retro | 1,126 | 15% | 169 | 0.02 | 0.02 | 8 | $70 | 100% | 40% | 2 | 60% | 20% | 0.8 | 0.6 | 1.0 |
| 1191 | Office_PC | Energy Star Server | Biz-Custom | Other | ROB | 1,621 | 23% | 368 | 0.04 | 0.04 | 8 | $118 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.2 |
| 1192 | Office_PC | Server Virtualization | Biz-Custom | Other | ROB | 2 | 45% | 1 | 0.00 | 0.00 | 8 | $0 | 100% | 40% | 3 | 65% | 25% | 0.8 | 0.6 | 1.0 |
| 1193 | Office_PC | Electrically Commutated Plug Fans in data centers | Biz-Custom | Other | Retro | 86,783 | 18% | 15,778 | 1.90 | 1.87 | 15 | $480 | 100% | 40% | 3 | 65% | 20% | 0.8 | 0.7 | 21.9 |
| 1194 | Office_PC | High Efficiency CRAC unit | Biz-Custom | Other | ROB | 541 | 30% | 162 | 0.02 | 0.02 | 15 | $63 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 1.7 |
| 1195 | Office_PC | Computer Room Air Conditioner Economizer | Biz-Custom | Other | Retro | 764 | 47% | 358 | 0.04 | 0.04 | 15 | $82 | 100% | 40% | 4 | 65% | 20% | 0.8 | 0.6 | 2.9 |
| 1196 | Office_PC | Data Center Hot/Cold Aisle Configuration | Biz-Custom | Other | Retro | 4 | 25% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 5 | 3% | 10% | 0.8 | 0.6 | 1.7 |
| 1197 | Refrigeration | Strip Curtains | Biz-Prescriptive | Other | Retro | 37 | 50% | 18 | 0.00 | 0.00 | 4 | $10 | 100% | 40% | 1 | 10% | 30% | 0.7 | 0.5 | 0.4 |
| 1198 | Refrigeration | Bare Suction Line | Biz-Custom | Other | Retro | 23 | 93% | 21 | 0.00 | 0.00 | 15 | $4 | 100% | 40% | 2 | 0% | 50% | 0.7 | 0.6 | 3.5 |
| 1199 | Refrigeration | Floating Head Pressure Controls | Biz-Prescriptive | Other | Retro | 1,112 | 25% | 278 | 0.04 | 0.03 | 15 | $431 | 100% | 40% | 3 | 7% | 25% | 0.7 | 0.4 | 0.4 |
| 1200 | Refrigeration | Saturated Suction Controls | Biz-Custom | Other | Retro | 831 | 50% | 416 | 0.06 | 0.05 | 15 | $559 | 100% | 40% | 4 | 2% | 10% | 0.7 | 0.4 | 0.5 |
| 1201 | Refrigeration | Compressor Retrofit | Biz-Custom | Other | Retro | 813 | 20% | 163 | 0.02 | 0.02 | 15 | $477 | 100% | 40% | 5 | 23% | 25% | 0.7 | 0.4 | 0.2 |
| 1202 | Refrigeration | Electronically Commutated (EC) Walk-In Evaporator Fan Motor | Biz-Custom | Other | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 6 | 6% | 80% | 0.9 | 0.8 | 3.5 |
| 1203 | Refrigeration | Evaporator Fan Motor Controls | Biz-Custom | Other | Retro | 2,236 | 32% | 716 | 0.10 | 0.08 | 15 | $155 | 100% | 40% | 7 | 6% | 25% | 0.7 | 0.5 | 3.1 |
| 1204 | Refrigeration | Variable Speed Condenser Fan | Biz-Custom | Other | Retro | 2,960 | 50% | 1,480 | 0.21 | 0.16 | 15 | $1,170 | 100% | 40% | 8 | 9% | 25% | 0.7 | 0.4 | 0.8 |
| 1205 | Refrigeration | Refrigeration Economizer | Biz-Custom | Other | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 9 | 32% | 10% | 0.7 | 0.4 | 0.8 |
| 1206 | Refrigeration | Anti-Sweat Heater Controls MT | Biz-Custom | Other | Retro | 579 | 59% | 338 | 0.05 | 0.04 | 10 | $80 | 100% | 40% | 10 | 11% | 25% | 0.7 | 0.5 | 2.1 |
| 1207 | Refrigeration | Display Case Door Retrofit, Medium Temp | Biz-Prescriptive | Other | Retro | 1,584 | 36% | 578 | 0.08 | 0.06 | 12 | $686 | 100% | 40% | 11 | 3% | 25% | 0.7 | 0.4 | 0.5 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1208 | Refrigeration | Electronically Commutated (EC) Reach-In Evaporator Fan Motor | Biz-Custom | Other | Retro | 2,884 | 55% | 1,586 | 0.22 | 0.17 | 15 | $305 | 100% | 40% | 12 | 2% | 80% | 0.9 | 0.8 | 3.5 |
| 1209 | Refrigeration | Q-Sync Motor for Walk-In and Reach-in Evaporator Fan Motor | Biz-Custom | Other | Retro | 441 | 34% | 149 | 0.02 | 0.02 | 10 | $90 | 100% | 40% | 13 | 2% | 2% | 0.7 | 0.4 | 0.8 |
| 1210 | Refrigeration | Energy Star Reach-In Refrigerator, Glass Doors | Biz-Prescriptive | Other | ROB | 2,140 | 29% | 629 | 0.09 | 0.07 | 12 | $1,239 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.3 |
| 1211 | Refrigeration | Energy Star Reach-In Refrigerator, Solid Doors | Biz-Prescriptive | Other | ROB | 1,410 | 20% | 281 | 0.04 | 0.03 | 12 | $1,211 | 100% | 40% | 14 | 11% | 54% | 0.7 | 0.6 | 0.1 |
| 1212 | Refrigeration | Anti-Sweat Heater Controls LT | Biz-Custom | Other | Retro | 2,016 | 68% | 1,361 | 0.19 | 0.15 | 10 | $91 | 100% | 40% | 15 | 4% | 25% | 0.7 | 0.6 | 7.3 |
| 1213 | Refrigeration | Display Case Door Retrofit, Low Temp | Biz-Prescriptive | Other | Retro | 2,922 | 50% | 1,453 | 0.20 | 0.16 | 12 | $686 | 100% | 40% | 16 | 4% | 25% | 0.7 | 0.5 | 1.2 |
| 1214 | Refrigeration | Energy Star Reach-In Freezer, Glass Doors | Biz-Prescriptive | Other | ROB | 6,374 | 20% | 1,275 | 0.18 | 0.14 | 12 | $1,651 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.4 |
| 1215 | Refrigeration | Energy Star Reach-In Freezer, Solid Doors | Biz-Prescriptive | Other | ROB | 4,522 | 7% | 305 | 0.04 | 0.03 | 12 | $1,521 | 100% | 40% | 17 | 4% | 54% | 0.7 | 0.6 | 0.1 |
| 1216 | Refrigeration | Refrigeration - Custom | Biz-Custom | Other | Retro | 7 | 2% | 0 | 0.00 | 0.00 | 10 | $0 | 100% | 40% | 18 | 70% | 25% | 0.7 | 0.4 | 0.3 |
| 1217 | Refrigeration | Retro-commissioning_Refrigerator Optimization | Biz-Custom RCx | Other | Retro | 5 | 21% | 1 | 0.00 | 0.00 | 5 | $0 | 100% | 40% | 19 | 70% | 25% | 0.7 | 0.5 | 1.2 |
| 1218 | Refrigeration | Energy Star Ice Machine | Biz-Prescriptive | Other | ROB | 6,993 | 10% | 721 | 0.10 | 0.08 | 10 | $222 | 100% | 40% | 20 | 8% | 44% | 0.7 | 0.6 | 1.6 |
| 1219 | Refrigeration | ESTAR Refrigerated Vending Machine | Biz-Prescriptive | Other | ROB | 1,278 | 12% | 153 | 0.02 | 0.02 | 14 | $500 | 100% | 40% | 21 | 5% | 30% | 0.7 | 0.4 | 0.2 |
| 1220 | Refrigeration | LED Refrigerated Display Case Lighting Average 6W/LF | Biz-Prescriptive | Other | Retro | 115 | 74% | 84 | 0.01 | 0.01 | 9 | $11 | 100% | 40% | 22 | 7% | 35% | 0.7 | 0.5 | 3.4 |
| 1221 | Ventilation | Pump and Fan Variable Frequency Drive Controls (Fans) | Biz-Custom | Other | Retro | 2,627 | 20% | 525 | 0.08 | 0.07 | 15 | $227 | 100% | 40% | 1 | 100% | 32% | 0.8 | 0.5 | 2.6 |
| 1222 | Ventilation | Demand Control Ventilation | Biz-Custom | Other | Retro | 2,166 | 43% | 940 | 0.14 | 0.12 | 15 | $168 | 100% | 40% | 2 | 100% | 32% | 0.8 | 0.6 | 3.8 |
| 1223 | Ventilation | High Volume Low Speed Fan, 20 | Biz-Custom | Other | Retro | 19,919 | 82% | 16,287 | 2.39 | 2.12 | 15 | $4,130 | 100% | 40% | 3 | 10% | 32% | 0.8 | 0.6 | 2.7 |
| 1224 | Ventilation | High Volume Low Speed Fan, 22 | Biz-Custom | Other | Retro | 21,909 | 83% | 18,277 | 2.69 | 2.37 | 15 | $4,190 | 100% | 40% | 4 | 10% | 32% | 0.8 | 0.6 | 3.0 |
| 1225 | Ventilation | High Volume Low Speed Fan, 24 | Biz-Custom | Other | Retro | 23,903 | 82% | 19,579 | 2.88 | 2.54 | 15 | $4,230 | 100% | 40% | 5 | 10% | 32% | 0.8 | 0.6 | 3.2 |
| 1226 | WholeBldg_HVAC | HVAC - Energy Management System | Biz-Custom | Other | Retro | 13 | 8% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 1 | 100% | 10% | 0.8 | 0.6 | 1.7 |
| 1227 | WholeBldg_HVAC | GREM Controls | Biz-Custom | Other | Retro | 0 | 0% | 0 | 0.00 | 0.00 | 5 | $260 | 100% |  | 2 | 100% | 20% | 0.8 | 0.7 | 0.0 |
| 1228 | WholeBldg_HVAC | Retro-commissioning_Bld Optimization | Biz-Custom RCx | Other | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 40% | 3 | 100% | 0% | 0.8 | 0.6 | 5.7 |
| 1229 | WholeBldg | WholeBlg - Com RET | Biz-Custom | Other | Retro | 7 | 15% | 1 | 0.00 | 0.00 | 12 | $0 | 100% | 40% | 1 | 80% | 0% | 0.8 | 0.6 | 1.4 |
| 1230 | WholeBldg | Power Distribution Equipment Upgrades (Transformers) | Biz-Custom | Other | Retro | 1,150 | 1% | 6 | 0.00 | 0.00 | 30 | $8 | 100% | 40% | 2 | 100% | 20% | 0.8 | 0.4 | 1.0 |
| 1231 | WaterWasteWater | Water Supply & Wastewater treatment pumps and process efficiency | Biz-Custom | Industrial | Retro | 5 | 20% | 1 | 0.00 | 0.00 | 11 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.5 | 1.2 |
| 1232 | CompressedAir | Efficient Air Compressor Equipment | Biz-Custom | Industrial | ROB | 9 | 11% | 1 | 0.00 | 0.00 | 13 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.5 | 1.5 |
| 1233 | CompressedAir | Efficient Air Compressor Controls | Biz-Custom | Industrial | Retro | 15 | 7% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 1.5 |
| 1234 | HVAC | Efficient HVAC Equipment | Biz-Custom | Industrial | ROB | 8 | 13% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 4.3 |
| 1235 | HVAC | Efficient HVAC O&M | Biz-Custom | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 2.0 |
| 1236 | Lighting | Efficient Lighting Equipment | Biz-Prescriptive | Industrial | Retro | 2 | 50% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 4.2 |
| 1237 | Lighting | Efficient Lighting O&M | Biz-Custom | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.7 | 2.6 |
| 1238 | Machine Drive | Efficient MachDr Equipment | Biz-Custom | Industrial | ROB | 5 | 20% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 4.0 |
| 1239 | Machine Drive | Efficient MachDr O&M | Biz-Custom | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 1.8 |
| 1240 | Process Heat | Efficient ProcHeat Equipment | Biz-Custom | Industrial | ROB | 10 | 10% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 4.0 |
| 1241 | Process Heat | Efficient ProcHeat O&M | Biz-Custom | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 2.2 |
| 1242 | Process Refrig | Efficient ProcRefrig Equipment | Biz-Custom | Industrial | ROB | 6 | 17% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 3.8 |
| 1243 | Process Refrig | Efficient ProcRefrig O&M | Biz-Custom | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 1.6 |
| 1244 | Other Process | Efficient Other Facility Process Equipment | Biz-Custom | Industrial | ROB | 4 | 25% | 1 | 0.00 | 0.00 | 11 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.5 | 1.5 |
| 1245 | Other Process | Efficient Other Facility Process O&M | Biz-Custom | Industrial | Retro | 14 | 7% | 1 | 0.00 | 0.00 | 11 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.5 | 1.8 |
| 1246 | WholeBldg | Power Distribution (Transformers) | Biz-Custom | Industrial | Retro | 179 | 1% | 1 | 0.00 | 0.00 | 30 | $1 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.4 | 0.9 |

**Appendix E: C&I Measure Assumptions**

This file provides measure-level detail, including measure name, estimates of savings, costs, useful lives. A brief overview of key descriptor columns is provided below:
**Measure #:** Each measure permultation, in order. **End-use:** The end-use of each meaure. **Measure Name:** Generic measure name (multiple permutations for each measure). **Program:** Each measure is mapped to a program. **Building Type:** Each measure is 1 of 12 building types. **Replacement Type:** Market opportunity/replace-on-burnout (ROB), Retro (Retrofit), Recylce or New Construction (NC). **EE EUL:** measure useful life. End Use Measure Group: Categorizes measures competing to save the same kWh of energy used. **Base Saturation:** Saturation of baseline equipment (% of businesses with the measure). **EE Saturation:** % of existing equipment stock that is already efficient. **MAP Adoption Rate:** Long-term ultimate market adoption rate in the MAP scenario. **RAP Adoption Rate:** Long-term adoption rate in the RAP scenario. **TRC Score:** benefit-cost ratio in the measure-level screening (greater than 1.0 is cost-effective).

| Measure # | End-Use | Measure Name | Program | Building Type | Replacement Type | Base Annual Electric kWh Usage | % Elec Savings | Per Unit Elec Savings (kWh) | Per Unit Summer kW Savings | Per Unit Winter kW Savings | EE EUL | Measure Cost | MAP Incentive (%) | RAP Incentive (%) | End Use Measure Group | Base Saturation | EE Saturation | MAP Adoption Rate | RAP Adoption Rate | TRC Score |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1247 | WholeBldg | Strategic Energy Management | Biz-Custom SEM | Industrial | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.7 | 2.0 |
| 1248 | Motors | Efficient Motor Pmp Equipment - Q1 Cost | Biz-Agriculture | Agriculture | ROB | 8 | 13% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.7 | 65.1 |
| 1249 | Motors | Efficient Motor Pmp Equipment - Q2 Cost | Biz-Agriculture | Agriculture | ROB | 8 | 13% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.7 | 32.5 |
| 1250 | Motors | Efficient Motor Pmp Equipment - Q3 Cost | Biz-Agriculture | Agriculture | ROB | 8 | 13% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 13.0 |
| 1251 | Motors | Efficient Motor Pmp O&M | Biz-Agriculture | Agriculture | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.8 | 0.6 | 1.7 |
| 1252 | Refrigeration | Efficient Refrigeration Equipment | Biz-Agriculture | Agriculture | ROB | 6 | 16% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.7 | 0.5 | 3.5 |
| 1253 | Refrigeration | Refrigeration Equipment O&M | Biz-Agriculture | Agriculture | Retro | 33 | 3% | 1 | 0.00 | 0.00 | 3 | $0 | 100% | 0% | 2 | 100% | 25% | 0.7 | 0.5 | 1.5 |
| 1254 | Lighting | Efficient Lighting | Biz-Agriculture | Agriculture | Retro | 2 | 42% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 3.8 |
| 1255 | Ventilation | Efficient Ventilation | Biz-Agriculture | Agriculture | Retro | 2 | 53% | 1 | 0.00 | 0.00 | 10 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.5 | 1.5 |
| 1256 | HVAC | HVAC | Biz-Agriculture | Agriculture | ROB | 8 | 13% | 1 | 0.00 | 0.00 | 15 | $0 | 100% | 0% | 1 | 100% | 25% | 0.8 | 0.6 | 3.4 |

# APPENDIX F: PROGRAM PARTICIPATION TABLES

# APPENDIX F: PROGRAM POTENTIAL ASSUMPTIONS

**TABLE F-1 RESIDENTIAL PROGRAM MEASURE REBATES AND PARTICIPATION**

| | Rebate | Unit | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|
| **HEIP** | | | | | | | |
| **Residential Air Source Heat Pump** | $ 500.00 | per system | 68 | 95 | 122 | 149 | 176 |
| **Residential Central Air Conditioner** | $ 250.00 | per system | 32 | 45 | 58 | 70 | 83 |
| **Residential Ductless AC** | $ 200.00 | per system | 9 | 13 | 16 | 20 | 23 |
| **Residential Ductless Heat Pump** | $ 400.00 | per system | 80 | 111 | 143 | 175 | 207 |
| **Residential ENERGY STAR Room Air Conditioner** | $ 20.00 | per system | 230 | 322 | 414 | 505 | 597 |
| **Residential Heat Pump Water Heater** | $ 500.00 | per system | 5 | 7 | 9 | 10 | 12 |
| **Residential Attic Insulation** | $ 230.00 | per home (avg.) | 6 | 8 | 10 | 12 | 14 |
| **Residential Air Sealing** | $ 70.00 | per home (avg.) | 5 | 7 | 9 | 11 | 13 |
| **Residential Duct Sealing/Insulation** | $ 150.00 | per home (avg.) | 1 | 2 | 2 | 3 | 3 |
| **Residential Floor Insulation Above Crawlspace** | $ 220.00 | per home (avg.) | 6 | 8 | 10 | 13 | 15 |
| **Residential Smart Thermostat** | $ 50.00 | per thermostat | 166 | 233 | 299 | 365 | 432 |
| Market Placeholder | | | | | | | |
| **Residential Smart Thermostat** | $ 50.00 | per thermostat | - | 113 | 142 | 170 | 198 |
| **Residential Low Income Smart Thermostat** | $ 75.00 | per thermostat | - | 209 | 261 | 314 | 366 |
| **Residential ENERGY STAR Air Purifier** | $ 30.00 | per Purifier | - | 74 | 92 | 110 | 129 |
| **Residential ENERGY STAR Clothes Washer** | $ 50.00 | per washer | - | 156 | 195 | 233 | 272 |

TABLE F-2 LOW INCOME PROGRAM MEASURE REBATES AND PARTICIPATION

| | Rebate | Unit | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|
| Targeted Energy Efficiency | | | | | | | |
| **Air Source Heat Pump 14 SEER – Electric Furnace Baseline** | $ 3,000.00 | per system | 40 | 51 | 61 | 71 | 81 |
| **Residential Heat Pump Water Heater** | $ 2,000.00 | per system | 53 | 66 | 79 | 92 | 105 |
| **Residential Ductless Heat Pump** | $ 520.00 | per system | 48 | 61 | 73 | 85 | 97 |
| **Residential Air Sealing** | $ 70.00 | per home | 3 | 4 | 5 | 6 | 6 |
| **Residential Attic Insulation** | $ 500.00 | per home | 28 | 35 | 41 | 48 | 55 |
| **Residential Bathroom Aerator 1.0 gpm** | $ 1.00 | per aerator | 75 | 93 | 112 | 131 | 149 |
| **Residential Duct Sealing/Insulation** | $ 150.00 | per home | 49 | 62 | 74 | 86 | 98 |
| **Residential ENERGY STAR Room Air Conditioner** | $ 25.00 | per system | 38 | 48 | 57 | 67 | 76 |
| **Residential Floor Insulation Above Crawlspace** | $ 160.00 | per home | 7 | 9 | 11 | 13 | 14 |
| **Residential Water Heater Wrap** | $ 6.67 | per heater | 42 | 40 | 48 | 56 | 64 |
| **Residential Air Source Heat Pump – Code Baseline** | $ 2,500.00 | per system | 10 | 13 | 15 | 18 | 20 |

TABLE F-3 COMMERCIAL PROGRAM MEASURE REBATES AND PARTICIPATION

| | Rebate | Unit | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|
| **Commercial Prescriptive** | | | | | | | |
| **Commercial Air Conditioner** | $ 40.00 | per ton | - | 5 | 20 | 22 | 25 |
| **Commercial Combination Ovens** | $ 1,430.00 | per oven | - | - | 2 | 2 | 2 |
| **Commercial Fryers** | $ 500.00 | per fryer | - | - | 2 | 2 | 2 |
| **Commercial Steam Cookers** | $ 1,380.00 | per cooker | - | - | 1 | 1 | 1 |
| **Commercial Dishwasher** | $ 220.00 | per washer | - | - | 1 | 1 | 1 |
| **Commercial Smart Thermostat** | $ 50.00 | per thermostat | - | 44 | 50 | 56 | 62 |
| **Packaged Terminal Heat Pumps** | $ 250.00 | per ton | - | 3 | 3 | 4 | 4 |
| **Geothermal Heat Pump** | $ 1,000.00 | per system | - | 2 | 3 | 3 | 3 |
| **Commercial Air Source Heat Pump** | $ 1,000.00 | per system | - | 10 | 12 | 13 | 14 |
| **Commercial Heat Pump Water Heater** | $ 500.00 | per system | - | 6 | 7 | 7 | 8 |
| **LED Downlight Fixture** | $ 9.00 | per fixture | 610 | 701 | 792 | 884 | 975 |
| **LED High Bay Fixture** | $ 75.00 | per fixture | 79 | 90 | 102 | 114 | 126 |
| **LED Low Bay Fixture** | $ 10.00 | per fixture | 498 | 573 | 647 | 722 | 797 |
| **LED Exterior Area Lighting** | $ 75.00 | per fixture | 721 | 829 | 937 | 1,045 | 1,153 |
| **LED Refrigerated Display Case Lighting** | $ 3.67 | per foot | 2,613 | 3,005 | 3,397 | 3,789 | 4,181 |
| **LED Linear Tube Replacement** | $ 3.00 | per lamp | 18,133 | 20,852 | 23,572 | 26,292 | 29,012 |
| **LED Troffer** | $ 20.00 | per fixture | 593 | 681 | 770 | 859 | 948 |
| **LED Wallpack** | $ 75.00 | per fixture | 483 | 555 | 628 | 700 | 773 |
| **Network Lighting Controls** | $ 0.20 | per watt reduced | 181,614 | 208,856 | 236,098 | 263,340 | 290,582 |
| **Occupancy Sensors** | $ 30.00 | per control | 872 | 1,002 | 1,133 | 1,264 | 1,394 |
| **Daylighting Controls** | $ 20.00 | per control | 793 | 911 | 1,030 | 1,149 | 1,268 |
| **Commercial Custom** | | | | | | | |
| **Cooling** | $ 0.14 | per kwh | - | - | 127,047 | 177,866 | 228,685 |
| **Refrigeration** | $ 0.14 | per kwh | - | - | 201,616 | 282,262 | 362,908 |
| **Compressed Air** | $ 0.14 | per kwh | - | - | 24,538 | 34,353 | 44,168 |
| **Motors** | $ 0.14 | per kwh | - | - | 69,811 | 97,736 | 125,661 |
| **Ventilation** | $ 0.14 | per kwh | - | - | 254,679 | 356,550 | 458,422 |
| **Miscellaneous** | $ 0.14 | per kwh | - | - | 30,854 | 43,195 | 55,537 |
| **Whole Building HVAC Controls** | $ 0.14 | per kwh | - | - | 41,232 | 57,725 | 74,218 |

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

KENTUCKY POWER
An AEP Company

# 2023 POTENTIAL STUDY

June
2023

FINAL REPORT

prepared by
GDS ASSOCIATES INC
BRIGHTLINE GROUP

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_21** | Refer to the Hearing Testimony of Alex Vaughn. Provide the dates of the PJM Base Residual Auction and any incremental auction(s) for the 2022/2023 delivery year. |

**RESPONSE**

The 22/23 delivery year had a Base Residual Auction (BRA) & Third Incremental Auction (3IA), only. Those windows opened on 5/19/21 and 2/28/22, respectively.

Witness: Alex E. Vaughan

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_22** | Provide the PJM Incremental Auction and Base Residual Auction results for the 2022/2023 delivery year. |

**RESPONSE**

The BRA cleared at $50 MW-Day while the 3IA cleared at $19 MW-Day. The BRA report is publicly available on PJM's website at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-base-residual-auction-report.ashx

Witness: Alex E. Vaughan

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_23** | Provide the name, employer, and position of any person still employed with firsthand knowledge of the discussion or decision to not renew the Rockport Unit Power Agreement (UPA). |

**RESPONSE**

Brett Mattison, President and Chief Operating Officer, Southwestern Electric Power Company.

Witness: Brian K. West

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_24** | Provide a timeline of the decision to not renew the Rockport UPA. Include in the response the date that Kentucky Power made the final decision. |

**RESPONSE**

By its terms, the August 1, 1984 Unit Power Agreement by and between Kentucky Power Company and AEP Generating Company (the "Rockport UPA") became "effective with the date of commercial operation of Rockport Unit No. 1" and, after its term was extended in 2004, "continue[d] in effect through December 7, 2022."[2] The Rockport UPA did not contain any term or provision that conveyed to Kentucky Power the right to renew the Rockport UPA upon its expiration.

Because the Rockport UPA did not provide Kentucky Power with a right to renew that agreement, the Company cannot identify the date on which it made a "final decision to not renew the Rockport UPA." Nonetheless, beginning at least as early as February 2019, Kentucky Power consistently conveyed to the Commission the Company's expectation that the Rockport UPA would terminate in 2022, that Kentucky Power would not seek to extend or negotiate a new Rockport UPA, and that the Company expected that the Rockport UPA would be replaced with lower cost capacity.[3] In its 2019 environmental compliance plan proceeding, Kentucky Power indicated that "the Company [did] not intend to extend the UPA beyond December 7, 2022," and that it "currently expect[ed] that the Rockport UPA [would] expire and not be renewed."[4] The Company further stated that, if the Company's decision to not renew the Rockport UPA changed, then Kentucky Power would seek Commission approval to extend the UPA.[5]

[2] Rockport UPA, Section 6.
[3] *See, e.g.,* Case No. 2018-00418, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 17 (Feb. 8, 2019).
[4] *See* Case No. 2019-00389, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 6 (Jan. 31, 2020).
[5] *Id.*

On July 17, 2019, the U.S. District Court for the Southern District of Ohio in *United States et al., v. American Electric Power Service Corp, et al*., Civil Action No. C2-99-1182 and consolidated cases, issued an Order approving a Fifth Joint Modification to the Consent Decree entered in that action (the "NSR Consent Decree"). Paragraph 140 of the NSR Consent Decree, as modified by the Fifth Joint Modification, expressly states that "AEP Defendants **must** Retire Rockport Unit 1 by no later than December 31, 2028."[6]. In addition to the Rockport UPA not providing Kentucky Power a right to renew the Rockport UPA upon its expiration, the requirement to retire Rockport Unit 1 by no later than December 31, 2028, eliminated the possibility of a long-term renewal of the Rockport UPA.

In December 2020, the Company again communicated to the Commission that Kentucky Power would not renew the Rockport UPA. During the December 10, 2020 hearing in the Company's 2019 integrated resource plan proceeding, Kentucky Power's then-President and Chief Operating Officer, Brett Mattison, testified that the Rockport UPA would end in December 2022 and that the Rockport UPA represented "a nonfuel issue that [Kentucky Power] **definitely** [was] going to walk away from in December [2022]."[7] In response to a question from Staff Counsel Ms. Frederick asking, "[r]egarding the Rockport UPA, explain whether Kentucky Power has changed its plans and is now considering renewing the lease," Company Witness West testified: "No, we have not changed our plans. **Our plans continue to be that the UPA will expire, it will not be renewed**."[8]In its February 8, 2021, Application in Case No. 2021-00004, Kentucky Power further stated that "[t]he Rockport Unit Power Agreement expires December 7, 2022. Kentucky Power has elected not to renew the agreement."[9] The Company also confirmed in a March 26, 2021 response to a Staff data request that its decision "not to renew the Rockport UPA [was] final."[10]

Witness: Brian K. West

[6] *Available at*: sargus-bizhub-20190717162026 (epa.gov) (emphasis added).
[7] Case No. 2019-00443, Hearing Video Record at 9:37:02AM (Dec 10, 2020) (emphasis added).
[8] Case No. 2019-00443, Hearing Video Record at 10:15:06AM (Dec 10, 2020) (emphasis added).
[9] Case No. 2021-00004, Application at paragraph 5 (Feb. 8, 2021).
[10] Case No. 2021-00004, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 5 (Mar. 26, 2021).

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_25** | Provide all meeting minutes of the Mitchell Operating Committee, including but not limited to any specially called meetings, for the period beginning August 1, 2019, to the present date. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_25_Attachment1 for the requested information.

Witness: Timothy C. Kerns

**Date:** March 5, 2021

**Time:** 9:00 AM EST

Tim Kerns led the meeting, introducing new members to the Operating Agreement and the requirements of same.

Presentations were made on the topics reflected on the agenda and in the associated PowerPoint document.

Lee McGuire covered action items, of which there was one:

- At the request of Doug Rosenberger, Darryl Scott will contact Josh Snodgrass at Mitchell Plant to determine a more-agreeable testing schedule for gypsum (currently every 4 hours), to see if this can be worked into the upcoming negotiations with CertainTeed.

There was consensus among the Committee members that a 4th Quarter meeting is desirable. Lee McGuire will get this meeting scheduled.

# Mitchell Operating Committee

2021 ANNUAL MEETING

MARCH 5, 2021

# Agenda

| | |
|---|---|
| ❖Welcome | Kerns |
| ❖Introductions | All |
| ❖Purpose of Meeting | Kerns |
| ❖Review 2021 Capital and O&M Budget | Belter |
| ❖Review 2022 – 2025 Capital Forecast | Belter |
| ❖Unit Operation – March 2021 | Beller |
| ❖Review Fuel & Consumables Status | Leskowitz |
| ❖Review Environmental Compliance Plan and Allowance | March |
| ❖Open Discussion | All |
| ❖Takeaways and Action Items | McGuire |
| ❖Adjourn | |

# Mitchell Operation Agreement and Committee

# Mitchell Operating Agreement

- Operating Agreement was filed and ordered under KPSC Case No. 2014-00396

- Article 7 of the Operating Agreement describes the Operating Committee and Operations

ARTICLE SEVEN

OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

# Mitchell Operating Agreement

- Operating Committee shall consist of one representative and one alternate from each Owner (KPCo and WPCo) and the Agent (AEP).

- Operating Committee Members:
  - Tim Kerns – VP Generating Assets (Agent Rep)
  - Brett Mattison – President and COO KPCo
  - Brian West – VP KPCo Regulatory and Finance (KPCo Alternate)
  - Chris Beam – President and COO APCo / WPCo
  - Mike Zwick – VP APCo Generating Assets (APCo / WPCo Alternate)
  - Lee McGuire – Manager-Planning and Analysis (Agent Rep)

# 2021 -2025 Control Budget and Forecast

# Control Budget and Forecast

| Mitchell Plant & ML Major Projects - Direct Cost Control Budgets | | | | | | |
|---|---|---|---|---|---|---|
| Sum of Ctrl $ | | By Year | | | | |
| Budget | Type | 2021 | 2022 | 2023 | 2024 | 2025 |
| Capital | ML 1 SCR Catalyst | $1,837,678 | $59,703 | | $457,000 | $2,302,000 |
| | ML 2 SCR Catalyst | $424,000 | $2,138,000 | | $457,000 | $2,302,000 |
| | ML CCR-ELG | $13,481,714 | $28,886,154 | $63,784,342 | $6,313,371 | $1,013,920 |
| | ML DSI Project | | $3,999,237 | $4,186,591 | | |
| | ML Haul Road Relocate | | $3,816,927 | | | |
| | ML Landfill Expansion | $510,000 | $42,421 | $10,366,423 | $3,155,329 | |
| | ML1 Air Heater Basket Repl | | $5,112,000 | | | |
| | ML1 Cooling Tower Repl | | $5,000,000 | | | |
| | ML1 HP/1st RH Rotor Inspect | | $3,390,000 | | | |
| | ML1 Lower Sidewall | | $2,000,000 | | | |
| | ML2 Air Heater Basket Repl | $362,000 | $4,750,000 | | | |
| | ML2 Cooling Tower Comp | $3,925,000 | $2,287,000 | | | |
| | ML2 Cooling Tower Repair | | | $110,661 | $3,036,064 | $4,116,446 |
| | ML2 Cooling Tower Shell | | | $196,611 | $3,423,997 | $4,505,543 |
| | ML2 ESP Upgrades | $90,004 | $7,295,379 | | | |
| | ML2 HP/2ndRH Rotor Inspect | | | | $3,234,000 | |
| | ML2 HP/RH Turbine Inspect | | | | $3,234,000 | |
| | Partial Removal Old Stack | | $930,000 | | | |
| | Phase 2 GSU Transformer | $3,360,000 | $1,440,000 | | | |
| | Plant Blankets | $4,500,677 | $15,457,203 | $8,440,563 | $6,452,230 | $7,733,287 |
| | PPB | $2,195,283 | $2,348,006 | $2,443,055 | $2,460,330 | $2,525,742 |
| **Capital Total** | | **$30,686,355** | **$88,952,030** | **$89,528,246** | **$32,223,321** | **$24,498,938** |
| O&M | Base Cost of Operations | $25,207,040 | $25,863,666 | $27,522,574 | $27,989,434 | $29,613,766 |
| | Non-Outage Maintenance | $5,308,050 | $5,432,897 | $5,823,819 | $5,910,195 | $5,654,949 |
| | Scheduled Outage | $4,239,970 | $14,250,064 | $5,302,000 | $8,094,000 | $7,946,000 |
| **O&M Total** | | **$34,755,060** | **$45,546,627** | **$38,648,393** | **$41,993,629** | **$43,214,715** |
| **Grand Total** | | **$65,441,415** | **$134,498,657** | **$128,176,639** | **$74,216,950** | **$67,713,653** |

# Fuel Procurement and Reagents

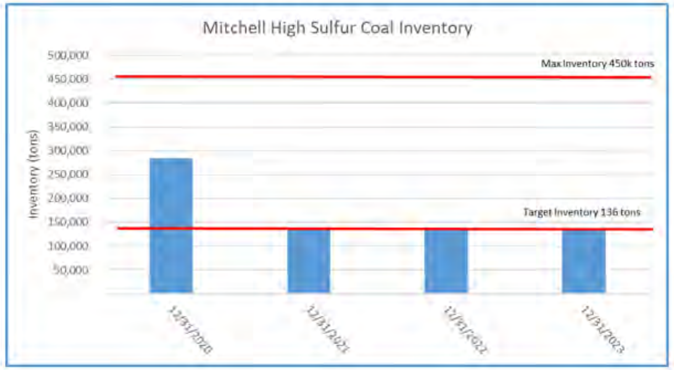
# Coal Procurement Strategy

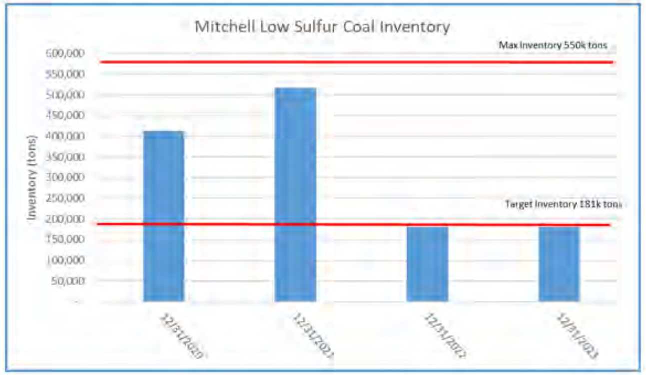
- **Inventory Analysis**

  Projected burn used in scenario below is based on Q1 2021 Forecast

  The forecasted fuel blend represents 80% high sulfur and 20% low sulfur on Unit 1 and 60% high sulfur and 40% low sulfur on Unit 2

  - Intend to flex coal blends on Unit 1 to assist with low sulfur inventory pile while optimizing unit offer price



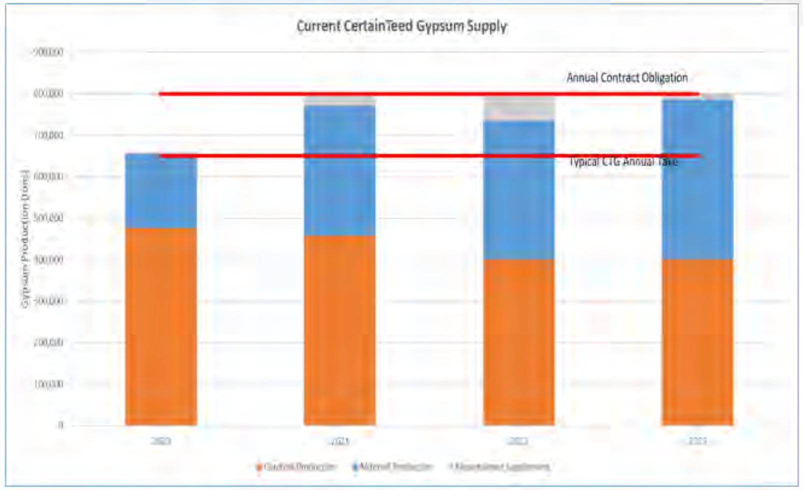




| **Mitchell High Sulfur** | 2021 | 2022 | 2023 |
|---|---|---|---|
| **Beginning Inventory Level** | 283,636 | 135,823 | 135,822 |
| **Total Commitments** | 1,020,907 | 1,000,000 | 1,000,000 |
| **Projected Burn** | 1,495,055 | 1,679,449 | 1,945,558 |
| **Open Position** | 326,335 | 679,448 | 945,559 |
| **Ending Inventory** | 135,823 | 135,822 | 135,823 |
| ***Delivered $/MMBtu*** | *$1.62* | *$1.57* | *$1.53* |

| **Mitchell Low Sulfur** | 2021 | 2022 | 2023 |
|---|---|---|---|
| **Beginning Inventory Level** | 412,262 | 516,588 | 181,097 |
| **Total Commitments** | 700,457 | 250,000 | - |
| **Projected Burn** | 596,131 | 669,677 | 841,562 |
| **Open Position** | - | 84,186 | 841,562 |
| **Ending Inventory** | 516,588 | 181,097 | 181,097 |
| ***Delivered $/MMBtu*** | *$2.79* | *$2.76* | *$2.67* |

# AEP Gypsum Supply to CertainTeed (CTG)

- **Current Contract Analysis**
  - Cardinal provided 475,000 tons in 2020 inclusive of landfill tons and at least 400,000 tons in other years on current slide
  - Mountaineer gypsum needed in current case to meet the production needs of CTG
  - Supply levels below CTG contractual annual level creates liquidated damage exposure risk to KPCO and Cardinal up to $20 per ton
  - Should AEP decide to walk away from contract, "failure to supply" exposure of $75M through 2023, then $60M beginning in 2024
- **Proposed Contract Points**
  - All production from ML and MT will be sold to CTG . Cardinal has separate agreement with CTG.
  - No mins, as produced. LDs are not a part of the proposed agreement.
  - Dock facilities must be maintained at ML, or infrastructure sold to CTG.

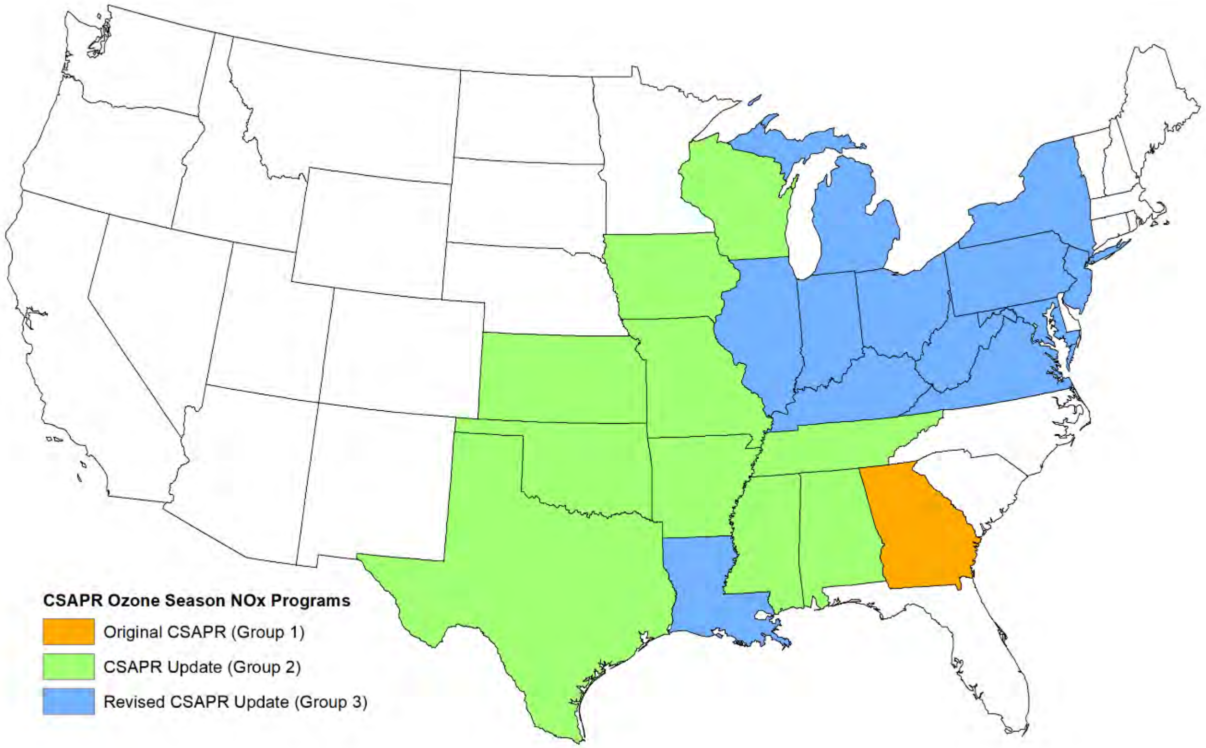



# Reagents Discussion

- Limestone
  - Trialed new sourcing with much better logistics. Delivered pricing will go from ~$33.67/ton to ~$19.02/ton.
  - Expecting a 43% savings in the delivered cost of the Limestone, approximately a $3 million savings on a $7 million spend for 2021.
  - Reducing the Limestone $/MWh from ~$1.36 to ~$0.77.
- High Reactivity Hydrated Lime conversion
  - Completed testing at Mitchell (800 MW unit). Lhoist favored over Mississippi Lime product.
  - Currently engineering has plans to test Amos 3 (1300 MW unit) around April 1.
  - Transition in our forecasting system planned for July 2023.
- Trona
  - 2021, servicing out of MIE milling facility. Likely to continue through 2022.
  - 2023 will see the plants serviced via rail cars as the transition is completed.
- Urea
  - Current contract runs through 2021 and will conduct an RFP in late Q2. Typically a 5- year agreement.
- Hydrated Lime
  - Used for waste water treatment (WWT). Current contract runs through 2022.

# Environmental Update

# Revised CSAPR Updated Coverage



KENTUCKY POWER

# What's in Store for 2021

2021***

**2021 Operating Co. Positions (tons)**

| | | SO2 | ANNx | OSNx |
|---|---|---|---|---|
| | APCo | 8,365 | 6,842 | 357 |
| | IMCo | 23,013 | 14,934 | 1,173 |
| Enter zero "0" below to hide | KPCo | 7,279 | 4,715 | 624 |
| AGR data, else enter 1 | WPCo | 2,021 | 1,835 | 448 |
| 0 | | 0 | 0 | 0 |
| | PSO | 0 | | 953 |
| TEXAS SO2 Program 2019+ | SWEPCo | 17,132 | | 1,088 |
| | Total | 40,678 | 28,326 | 4,644 |

**2021 AEP State Position Summary (tons)**

| State/OPCo | SO2 | ANNx | OSNx |
|---|---|---|---|
| AGR | 0 | 0 | 0 |
| KPCo | 4,061 | 2,636 | 207 |
| IMCo | 23,013 | 14,934 | 1,173 |
| Ind. Total | 27074 | 17570 | 1380 |
| KPCo | 1,197 | 244 | (30) |
| Ky. Total | 1197 | 244 | (30) |
| | | | |
| BPCo | 0 | 0 | 0 |
| JOU | 682 | 0 | 0 |
| APCo | 0 | 0 | (2) |
| Oh. Total | 14063 | 6581 | (171) |
| APCo | 2,457 | 1,532 | 3 |
| Va. Total | 2457 | 1532 | 3 |
| AGR | 0 | 0 | 0 |
| APCo | 5,908 | 5,310 | 356 |
| KPCo | 2,021 | 1,835 | 448 |
| WPCo | 2,021 | 1,835 | 448 |
| WVa Total | 9950 | 8980 | 1251 |
| | | | |
| IOU | | | (14) |

2021 PROPOSED

**AEP DR Emissions by State as % of AEP's Allocations**

| Limit 118% SO2 % | Limit 118% ANNx % | Limit 121% OSNx % | |
|---|---|---|---|
| 13% | 11% | 33% | Indiana |
| 18% | 77% | 111% | Kentucky |
| 0% | 5% | 103% | Ohio |
| 6% | 15% | 97% | Virginia |
| 66% | 57% | 78% | West Virginia |

# Ozone Season NOX Allowance Position – 2021

| 2021 AEP Ozone NOx Emissions/Allocations/Positions (tons) | | | | | | |
|---|---|---|---|---|---|---|
| Op Co | State | Budget | Projected Emissions | Allowance Surplus (Shortfall) | 2021 Op Co Aggregate Gr2/Gr3 | EOY Adj'd Bank |
| | | | | | | |
| | | | | | | |
| APCO | OH | 69 | 71 | (2) | | |
| APCO | VA | 110 | 107 | 3 | 357 | |
| APCO | WV | 4227 | 3,871 | 356 | | |
| I&M | IN | 1,749 | 576 | 1173 | 1173 | |
| KPCO | IN | 309 | 102 | 207 | | |
| KPCO | KY | 282 | 312 | (30) | 624 | |
| KPCO | WV | 704.5 | 257 | 448 | | |
| WPCO | WV | 704.5 | 257 | 448 | 448 | |
| PSO | OK | 2,738 | 1,928 | 810 | 953 | |
| PSO | TX | 143 | 0 | 143 | | |
| SWEPCO | AR | 779 | 654 | 125 | 976 | |
| SWEPCO | LA | 659 | 546 | 113 | 113 | |
| SWEPCO | TX | 3,539 | 2,688 | 851 | | |
| | | AEP OSNx Gr2 Total | | 1929 | | |
| | | AEP OSNx Gr3 Total | | 2715 | | |

# What Changes in 2024

2024***

**2024 Operating Co. Positions (tons)**

| | | SO2 | ANNx | OSNx |
|---|---|---|---|---|
| | APCo | 7,882 | 6,488 | (1,029) |
| | IMCo | 26,866 | 17,094 | 315 |
| Enter zero "0" below to hide | KPCo | 7,192 | 4,798 | (132) |
| AGR data, else enter 1 | WPCo | 1,254 | 1,434 | (46) |
| 0 | AGR | 0 | 0 | 0 |
| | PSO | 0 | | 359 |
| TEXAS SO2 Program 2019+ | SWEPCo | 28,406 | | 643 |
| | Total | 43,194 | 29,814 | 110 |

**2024 AEP State Position Summary (tons)**

2024 PROPOSED

**AEP DR Emissions by State as % of AEP's Allocations**

| State/OPCo | SO2 | ANNx | OSNx | SO2 % (Limit 118%) | ANNx % (Limit 118%) | OSNx % (Limit 121%) | |
|---|---|---|---|---|---|---|---|
| AGR | 0 | 0 | 0 | | | | |
| KPCo | 4,653 | 2,949 | 0 | | | | |
| IMCo | 26,866 | 17,094 | 315 | | | | |
| **Ind. Total** | **31519** | **20043** | **315** | 6% | 5% | 60% | **Indiana** |
| KPCo | 1,285 | 415 | (86) | | | | |
| **Ky. Total** | **1285** | **415** | **(86)** | 12% | 61% | 139% | **Kentucky** |
| | | | | | | | |
| BPCo | 0 | 0 | 0 | | | | |
| JOU | 682 | 429 | 0 | | | | |
| APCo | 0 | 0 | (9) | | | | |
| **Oh. Total** | **14433** | **9370** | **0** | 0% | 3% | 113% | **Ohio** |
| APCo | 2,521 | 1,491 | (201) | | | | |
| **Va. Total** | **2521** | **1491** | **(201)** | 3% | 17% | 391% | **Virginia** |
| AGR | 0 | 0 | 0 | | | | |
| APCo | 5,361 | 4,997 | (819) | | | | |
| KPCo | 1,254 | 1,434 | (46) | | | | |
| WPCo | 1,254 | 1,434 | (46) | | | | |
| **WVa Total** | **7869** | **7865** | **(911)** | 73% | 62% | 119% | **West Virginia** |
| | | | | | | | |
| JOU | | | (112) | | | | |

# Ozone Season NOX Allowance Position – 2024

| 2024 AEP Ozone NOx Emissions/Allocations/Positions (tons) | | | | | | |
|---|---|---|---|---|---|---|
| Op Co | State | Budget | Projected Emissions | Allowance Surplus (Shortfall) | 2021 Op Co Aggregate Gr2/Gr3 | EOY Adj'd Bank |
| | | | | | | |
| | | | | | | |
| APCO | OH | 69 | 78 | (9) | | |
| APCO | VA | 69 | 270 | (201) | (1029) | |
| APCO | WV | 3689 | 4,508 | (819) | | |
| I&M | IN | 795 | 480 | 315 | 315 | |
| KPCO | IN | 0 | 0 | 0 | | |
| KPCO | KY | 220 | 306 | (86) | (132) | |
| KPCO | WV | 595 | 641 | (46) | | |
| WPCO | WV | 595 | 641 | (46) | (46) | |
| PSO | OK | 2,069 | 1,853 | 216 | 359 | |
| PSO | TX | 143 | 0 | 143 | | |
| SWEPCO | AR | 779 | 984 | (205) | 93 | |
| SWEPCO | LA | 634 | 84 | 550 | 550 | |
| SWEPCO | TX | 2,888 | 2,590 | 298 | | |
| | | AEP OSNx Gr2 Total | | 452 | | |
| | | AEP OSNx Gr3 Total | | (342) | | |

CONFIDENTIAL AND PROPRIETARY INFORMATION

# Closing Comments

# Open Discussion

# Action Items and Takeaways

# MITCHELL OPERATING COMMITTEE

## MINUTES

## October 20, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on October 20, 2021, at 3:00 p.m. (Eastern).

**Operating Representatives Present:**

(1) Chris Beam, President and Chief Operating Officer, Wheeling Power Company; (2) Brett Mattison, President and Chief Operating Officer, Kentucky Power Company; and (3) Tim Kerns, VP Generating Assets, Fossil & Hydro Generation, American Electric Power Service Corporation.

Constituting all of the Operating Representatives. Also present were John Crespo, Mike Zwick, Christen Blend, Jim Bacha, Gary Spitznogle, Kathy Milenkovski, Brian West, Brian Rupp, and Raja Sundararajan.

Mr. Crespo acted as Secretary of the meeting of the Operating Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives approved the Agenda for the meeting, attached.

Ms. Blend, Mr. Bacha and Ms. Milenkovski, legal counsel for AEP, provide an update on (1) the KY Order on Application for Declaratory Order; (2) the WV Order on Petition to Reopen and Take Further Action; and (3) ELG/CCR environmental permitting matters. The Operating Representatives asked questions and engaged in further discussions regarding the matters presented. The Operating Representatives asked that additional information be presented at a future meeting by legal counsel regarding the environmental permits related to the Mitchell Plant.

Mr. Zwick provided an update on the status of the ELG/CCR engineering and construction. Mr. Zwick also provided an update on the status of the forecasted capital expenditures for the ELG/CCR Project and the status of the 2022 Budget, which is currently under review. The Operating Representative asked questions and engaged in further discussions regarding the matters presented.

The Operating Representatives took up discussion on the proposed Resolution set forth in the Agenda regarding the appointment of an independent engineer to evaluate the allocation of the capital costs of the CCR and ELG project in accordance with the orders issued by the public service commissions of West Virginia and Kentucky. The Operating Representatives discussed modifications to the proposed resolution to (1) affirmatively state that the independent engineer should be qualified to perform the work, and (2) require that the selection of the independent engineer by the Agent be presented to and ratified by the Operating Committee.

**WHEREFORE**, upon motion duly made and seconded, it was unanimously,

> **RESOLVED**, in order to ensure that neither Kentucky Power nor its customers will inappropriately bear the costs of the Mitchell ELG project, and to ensure that each Owner bears an equitable share of other costs of environmental compliance benefitting that Owner, the Operating Committee, pursuant to its authority under Section 7.2 of the Agreement, delegates to Agent authority to retain an independent engineer on behalf of the Owners, qualified for the work, at their equal cost and expense, to prepare an analysis of the appropriate allocation between the Owners of the capital and operating costs of the ELG and CCR projects, provided that the independent engineer selected by the Agent shall first be presented to and ratified by the Operating Committee in writing, and to take such further action in furtherance of the foregoing and provide such information of the Owners to the independent engineer as may be necessary or advisable in Agent's reasonable discretion.

Mr. Crespo, Secretary to the Operating Committee and legal counsel for AEP, reviewed the terms of the Agreement and the changes that could be made to address the matters raised in the orders issued by the public service commissions of West Virginia and Kentucky. The Operating Representative asked questions and engaged in further discussions regarding the matters presented.

The Operating Representatives took up discussion on the proposed Resolution set forth in the Agenda regarding the preparation of modifications to the Agreement to address the matters presented.

**WHEREFORE**, upon motion duly made and seconded, it was unanimously,

> **RESOLVED**, the Operating Committee directs Agent within 10 business days to prepare for its review proposed modifications to the Agreement and/or new agreements related to the ownership, operation, maintenance and future potential retirement of the Mitchell Plant that will address the matters raised in the orders issued by the Kentucky and West Virginia public service commissions, and other matters, including but not limited to provisions regarding: (1) transfer of plant operations and permits from Kentucky Power to Wheeling Power; (2) ensuring that neither Kentucky Power nor its customers will inappropriately bear the costs of the Mitchell ELG project; (3) ensuring that Wheeling Power is appropriately made responsible for capital and operating costs (including ELG costs) arising from directives of the West Virginia commission that Wheeling operate the Mitchell Plant beyond 2028; (4) prohibitions on Kentucky Power sharing in capacity and energy from the Mitchell Plant after December 31, 2028; (5) changes in the ownership of the Mitchell Plant to accommodate the continued operation of the Mitchell Plant without involvement of Kentucky Power or Kentucky jurisdictional customers; and (6) Any other provisions that the Agent may deem necessary or advisable to propose to the Owners.

There being no further business, the Operating Committee meeting was adjourned.

John C Crespo

John Crespo

Secretary

# MITCHELL OPERATING COMMITTEE

## AGENDA

## October 20, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") will be held on October 20, 2021, at 3:00 p.m. (Eastern).

**Invitees**: Operating Representatives: Tim Kerns (Agent), Brett Mattison (Kentucky Power), Chris Beam (Wheeling Power), Mike Zwick (Agent – Alternate)

Other Invitees: John Crespo (Secretary), Christen Blend, Jim Bacha, Gary Spitznogle, Kathy Milenkovski

**1. Call to Order**

A. Roll Call for Quorum

B. Review of Agenda

**2. Legal Update on ELG/CCR Certificate Proceedings in KY and WV** -- Legal Counsel

A. KY Order on Application for Declaratory Order

B. WV Order on Petition to Reopen and Take Further Action

C. ELG/CCR Environmental Permitting Update

**3. Update on CCR/ELG Projects** -- Tim Kerns

A. Update on ELG/CCR Planning and Construction Progress

B. Proposed Resolution for review by the Operating Committee:

**RESOLVED**, in order to ensure that neither Kentucky Power nor its customers will inappropriately bear the costs of the Mitchell ELG project, and to ensure that each Owner bears an equitable share of other costs of environmental compliance benefitting that Owner, the Operating Committee, pursuant to its authority under Section 7.2 of the Agreement, delegates to Agent authority to retain an independent engineer on behalf of the Owners, at their equal cost and expense, to prepare an analysis of the appropriate allocation between the Owners of the capital and operating costs of the ELG and CCR projects, and to take such further action in furtherance of the foregoing and provide such information of the Owners to the independent engineer as may be necessary or advisable in Agent's reasonable discretion.

**4. Update on CCR/ELG Budget** – Tim Kerns

A. Review of 2021 Budget

B. Review of Upcoming 2022 Budget Cycle Process

5. **Operating Agreement** – Tim Kerns

A. Review of Terms of Operating Agreement

B. Proposed Resolution for review by the committee:

**RESOLVED**, the Operating Committee directs Agent within 10 business days to prepare for its review proposed modifications to the Agreement and/or new agreements related to the ownership, operation, maintenance and future potential retirement of the Mitchell Plant that will address the matters raised in the orders issued by the Kentucky and West Virginia public service commissions, and other matters, including but not limited to provisions regarding:

(1) Transfer of plant operations and permits from Kentucky Power to Wheeling Power;

(2) Ensuring that neither Kentucky Power nor its customers will inappropriately bear the costs of the Mitchell ELG project;

(3) Ensuring that Wheeling Power is appropriately made responsible for capital and operating costs (including ELG costs) arising from directives of the West Virginia commission that Wheeling operate the Mitchell Plant beyond 2028;

(4) Prohibitions on Kentucky Power sharing in capacity and energy from the Mitchell Plant after December 31, 2028;

(5) Changes in the ownership of the Mitchell Plant to accommodate the continued operation of the Mitchell Plant without involvement of Kentucky Power or Kentucky jurisdictional customers; and

(6) Any other provisions that the Agent may deem necessary or advisable to propose to the Owners.

6. **Other Business**

7. **Adjournment**

# MITCHELL OPERATING COMMITTEE

## Minutes

## October 25, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on October 25, 2021, at 12:00 p.m. (Eastern).

**Operating Representatives Present:**

(1) Chris Beam, President and Chief Operating Officer, Wheeling Power Company; and
(2) Brett Mattison, President and Chief Operating Officer, Kentucky Power Company.

Constituting the Operating Representatives of the Owners. Also present were John Crespo, Christen Blend, Jim Bacha, Matt Satterwhite, Mike Zwick and Raja Sundararajan.

Mr. Crespo acted as Secretary of the meeting of the Operating Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives approved the Agenda for the meeting, attached.

Mr. Crespo, Secretary to the Operating Committee and legal counsel for AEP, presented the draft Mitchell Operation and Maintenance Agreement and the draft Mitchell Ownership Agreement. Mr. Crespo further presented the terms and conditions of the Mitchell Ownership Agreement to the Operating Representatives as set forth in the Agenda. The Operating Representatives asked questions of legal counsel and engaged in further discussions regarding the matters presented. The Owners requested that Mr. Crespo, as Secretary, summarize and record their comments, representing the views of the Owners on the agreements, and provide those comments to the Agent for further review. The summary prepared by Mr. Crespo at the request of the Owners is attached.

There being no further business, the Operating Committee meeting was adjourned.

John Crespo

Secretary

## John C Crespo

**From:** John C Crespo
**Sent:** Monday, October 25, 2021 3:43 PM
**To:** Randy G Ryan (rgryan@aep.com); Stephan T Haynes
**Cc:** Christian T Beam; Brett Mattison; Tim Kerns; Michael J Zwick
**Subject:** Mitchell Operating Committee Feedback

Randy and Steve, the Mitchell Operating Committee met today and we went over the draft Mitchell Operating Agreement and draft Mitchell Ownership Agreement. Based on our discussions, the Committee has asked me to provide the following feedback on various sections and definitions. We would plan to further discuss these items and any revisions proposed by AEP Service Corp. to the form of the documents at a future meeting of the Operating Committee.

- Recitals
  - Requested more information about the removal of AEPSC as a party.
  - Requested clarification on the title of the O&M Agreement – is the "M" maintenance or management, and would the latter be more appropriate.
- Section 1.8
  - Section reference to "ELG Expenses" could be confusing because it refers to investment and not expense. The term could be renamed to indicate it refers to capital investments.
  - The second line may be more clearly phrased, "an amount greater than 50% of any capital expenditures, including ELG [Investments], as contemplated…."
- Sections 6.4(d), 6.7(a), 6.7(b), 6.7(d), 7.2(f)
  - Should be worded to avoid the impression that KPCO is paying for a portion of ELG upgrades.
  - Ensuring that each section referring to the allocation of the costs of capital investments and O&M required by KPCO and WPCO to each comply with their CCR and CCR/ELG obligations, respectively, is described consistently in each affected section. Should be clear that the division is based on the independent engineer's evaluation. Defined terms should also be consistent with that process.
- Section 6.7(b)
  - Should be worded to avoid the impression that KPCO is paying for a portion of ELG upgrades.
  - Could be clearer if the proviso regarding KPCO sharing in ELG costs is revised or deleted. KPCO should pay its share of the costs identified by the IE that are necessary for it to comply with the CCR rules, and WPCO should pay its share of the costs identified by the IE that are necessary for it to comply with both the CCR and ELG rules.
- Section 7.6
  - Requested more information about separate dispatch and operating committee safeguards regarding use of coal inventory in times of coal scarcity.
- Section 9.6
  - The buyout standards were discussed and are being reviewed. Discussed whether the Operating Committee needs to address their use of good faith in considering future capacity commitments in PJM related to Mitchell after 2028.

Please let me know if you have any questions. --John

# MITCHELL OPERATING COMMITTEE

## AGENDA

## October 25, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") will be held on October 25, 2021, at 12:00 p.m. (Eastern).

**Invitees**: Operating Representatives: Tim Kerns (Agent), Brett Mattison (Kentucky Power), Chris Beam (Wheeling Power), Mike Zwick (Agent – Alternate)

Other Invitees: John Crespo (Secretary), Christen Blend, Jim Bacha, Randy Ryan, Mathew Satterwhite, Raja Sundararajan, Randy Ryan, Stephan Haynes

**1. Call to Order**

A. Roll Call for Quorum

B. Review of Agenda

**2. Operating Agreement** – Legal Counsel

A. Review of Terms of draft Operating and Ownership Agreements, including the following provisions of the draft Ownership Agreement:

- Section 1.5, regarding appointment of Wheeling as the operator.
- Section 1.8, regarding the funding of certain capital expenditures and ELG expenditures in the Capital Budget.
- Section 3.2, regarding early retirement.
- Section 6.4(d), regarding O&M expenses related to ELG upgrades.
- Section 6.7, regarding the funding of certain capital investments including ELG upgrades and upgrades with a depreciable life extending beyond 2028.
- Section 7.2(d), (f), related to inclusion in the Capital Budget of certain Owner-funded capital projects and determinations by a technical expert related to division of ELG expenses.
- Section 9.6, regarding buyout by Wheeling of Kentucky Power's ownership interests effective 12/31/2028 if an early retirement has not previously occurred, and related matters including valuation of said interest and other buyout procedures.
- Such other provisions as may be of interest to the Committee.

**6. Other Business**

**7. Adjournment**

# OPERATIONS AND MAINTENANCE AGREEMENT

by and between

**KENTUCKY POWER COMPANY, as the Non-Operator Owner**

and

**WHEELING POWER COMPANY, as the Operator**

Dated as of

[_________], 2021

# TABLE OF CONTENTS

**Page**

# MITCHELL PLANT OPERATIONS AND MAINTENANCE AGREEMENT

This OPERATIONS AND MAINTENANCE AGREEMENT (this "Agreement"), dated as of [__________] (the "Effective Date"), is entered by and between WHEELING POWER COMPANY, a West Virginia corporation (in its capacity as the operator of the Facility, "Operator" and in its capacity as an owner of the Facility, "WPCo") and KENTUCKY POWER COMPANY, a Kentucky corporation qualified as a foreign corporation in West Virginia (in its capacity as an owner of the Facility, the "Non-Operator Owner" and, together with WPCo, each an "Owner" and, together, the "Owners").

RECITALS

1. Owners each own an undivided Ownership Interest in the Facility (these and other capitalized terms are defined in Article II).

2. On the date hereof, WPCo and the Non-Operator Owner have entered into that certain Mitchell Plant Ownership Agreement, setting forth the respective rights, duties and obligations of the Owners with respect to each other and the Facility in their capacities as the Owners thereof (the "Ownership Agreement").

3. Pursuant to the Ownership Agreement, WPCo has agreed to manage the day-to-day operations and maintenance of the Facility as Operator pursuant to the terms of this Agreement.

4. Operator and the Non-Operator Owner desire to execute this Agreement to set forth the respective rights, duties and obligations of WPCo, in its capacity as Operator of the Facility, and the Non-Operator Owner, in its capacity as an Owner of an undivided interest as a co-tenant in the Facility.

NOW, THEREFORE, in consideration of the foregoing premises, and of the mutual covenants, undertakings and conditions set forth below, the Parties agree as follows:

## ARTICLE I - AGREEMENT

1.1 Agreement. This Agreement consists of the recitals, and the terms and conditions set forth in this Agreement, as well as the appendices that are referenced in the table of contents and attached to this Agreement.

1.2 Relationship of the Parties. Operator shall perform the Services in its capacity as an independent contractor of the Owners and as principal on its own behalf as an Owner. Subject to any limitations set forth in this Agreement and the Ownership Agreement, the Owners delegate to Operator, and Operator accepts from the Owners, the responsibility of providing the Services at the Facility. The Owners and Operator agree that the scope of delegation is strictly limited to the matters set forth in this Agreement and the Ownership Agreement. Without limiting the generality of the foregoing, the Owners retain the ultimate authority and obligation to determine whether and to what extent the Facility operates, and Operator shall not cause the Facility to generate power except as expressly directed to do so by the Owners or any dispatching authority specified by the Owners in accordance with the Ownership Agreement. For the avoidance of doubt, any provision of this Agreement requiring the delegation of authority, direction, consent or authorization with respect to the Owners shall mean the delegation, direction, consent or authorization of both Owners (or the Operating Committee) in accordance with the Ownership Agreement (except to the extent the Ownership Agreement gives exclusive authority to the Non-Operator Owner thereunder, in which case such delegation of authority, direction, consent or authorization with respect to the Owners shall mean exclusively the delegation, direction, consent or authorization of the Non-Operator Owner).

1.3 Entire Agreement. This Agreement, together with the Ownership Agreement, contains the entire agreement between the Parties with respect to Operator's provision of Services at the Facility and supersedes all prior negotiations, undertakings and agreements.

## ARTICLE II - DEFINITIONS

For all purposes of this Agreement (including the preceding sections and recitals), unless otherwise required by the context in which any defined term appears, capitalized terms have the meanings specified in this Article II. The singular includes the plural, as the context requires. The terms "includes" and "including" mean "including, but not limited to." The terms "ensure" and "reasonable efforts" will not be construed as a guarantee, but will imply only a duty to use reasonable efforts and care, consistent with Prudent Operation and Maintenance Practices, and will include reasonable expenditures of money and at least such efforts as Operator would undertake for its own assets, services or maintenance, or for services provided to an Affiliate. "Gross negligence" will not be construed as simple or ordinary negligence, it being the intent of the Parties to preserve a distinction between errors made inadvertently while attempting to perform with due care and actions taken with a knowing disregard for a foreseeable risk. "Day" (regardless of capitalization) shall mean a calendar day, unless specifically designated as a Business Day. "Month" (regardless of capitalization) shall mean a calendar month. References to articles, sections and appendices mean the articles and sections of, and appendices to, this Agreement, except where expressly stated otherwise.

"AEP" shall mean American Electric Power Company, Inc., a New York corporation and an Affiliate of WPCo.

"AEPSC" shall mean American Electric Power Service Corporation, a New York corporation and an Affiliate of WPCo.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly, controls, is controlled by, or is under common control with such Person. As used in this definition, "control" (including, with its correlative meanings, "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of securities or partnership or other ownership interests, by contract or otherwise. The Non-Operator Owner shall not be deemed an Affiliate of the Operator.

"Agreement" has the meaning set forth in the preamble to this Agreement.

"Applicable Law" means all laws (including common law), statutes, codes, acts, treaties, ordinances, orders, judgments, writs, decrees, injunctions, rules, regulations, Governmental Approvals, Permits, directives, and requirements of all Governmental Authorities (including with respect to the environment) having jurisdiction over an Owner, any other Person or entity (as to that Person or entity), this Agreement, any Facility asset or the Facility, as applicable.

"Bankruptcy" means a situation in which (i) a Person files a voluntary petition in bankruptcy or is adjudicated as bankrupt or insolvent, or files any petition or answer or consent seeking any reorganization, arrangement, moratorium, composition, readjustment, liquidation, dissolution or similar relief for itself under the present or future applicable United States federal, state or other statute or law relative to bankruptcy, insolvency or other relief for debtors, or seeks or consents to or acquiesces in the appointment of any trustee, receiver, conservator or liquidator of such Person or of all or any substantial part of its properties (the term "acquiesce," as used in this definition, includes the failure to file a petition or motion to vacate or discharge any order, judgment or decree within fifteen (15) days after entry of such order, judgment or decree); (ii) a court of competent jurisdiction enters an order, judgment or decree approving a petition filed against any Person seeking a reorganization, arrangement, moratorium, composition, readjustment, liquidation, dissolution or similar relief under the present or any future United States federal bankruptcy act, or any other present or future Applicable Law relating to bankruptcy, insolvency or other relief for debtors, and such Person acquiesces and such decree remains unvacated and unstayed for an aggregate of sixty (60) days (whether or not consecutive) from the date of entry thereof, or a trustee, receiver, conservator or liquidator of such Person is appointed with the consent or acquiescence of such Person and such appointment remains unvacated and unstayed for an aggregate of sixty (60) days, whether or not consecutive; (iii) a Person admits in writing its inability to pay its debts as they mature; (iv) a Person gives notice, to any Governmental Authority of insolvency or pending insolvency, or suspension or pending suspension of operations; or (v) a Person makes a general assignment for the benefit of creditors or takes any other similar action for the protection or benefit of creditors (other than in the ordinary course of such party's business).

"Budget" means an annual operating budget and annual capital budget adopted or amended pursuant to the Ownership Agreement.

"Business Day" means any day other than (i) a Saturday or Sunday or (ii) a day on which banks in West Virginia or Ohio are required or permitted to be closed.

"Claims" means any and all claims, assertions, demands, suits, investigations, inquiries, and proceedings.

"Confidential Information" means, with respect to each Party, all written or oral information of a proprietary, intellectual or similar nature, relating to the business, projects, operations, activities or affairs of a Party and its Affiliates, whether of a technical or financial nature or otherwise (including environmental assessment reports, financial information, business plans and proposals, ideas, concepts, trade secrets, know-how, processes, pricing of services or products, and other technical or business information, whether concerning this Agreement, each Party's respective businesses or otherwise) that has not been publicly disclosed and that the receiving Party acquires directly or indirectly from the disclosing Party.

"Cost Allocation Manual" means the Cost Allocation Manual of Operator and its Affiliates, as may be amended from time to time, as filed with FERC and, to the extent required, the WVPSC.

"Decommission" or "Decommissioning" shall mean the retirement, dismantlement and permanent removal of the generating units and other property, plant, and equipment comprising the Facility, including any common facilities associated with each generating unit that are to be permanently removed from service, the restoration of the Site and the removal or remediation of any hazardous materials or other contaminated equipment, materials, coal ash or wastes associated therewith, in a manner that meets the requirements of Applicable Law.

"Decommissioning Work" shall mean all work reasonably necessary or undertaken to Decommission the Facility, including work associated with the preparation and implementation of Decommissioning plans and the preparation, submittal and prosecution of all necessary applications with Governmental Authorities as required to Decommission the Facility in accordance with Applicable Law.

"Dollars" means United States Dollars, the lawful currency of the United States of America.

"Due Date" means, with respect to any Operator invoice, the date that is thirty (30) days following the date on which Operator submits the invoice to the Non-Operator Owner in accordance with Article VII. If such date does not fall on a Business Day, then the Due Date shall be the first Business Day after such date.

"Effective Date" means the date set forth in the preamble to this Agreement.

"Emergency" has the meaning set forth in Section 3.8.

"Encumbrance" means (i) any mortgage, charge, lien, pledge, hypothecation, title retention arrangement or other security interest, as or in effect as security for the payment of a monetary obligation or the observance of any other obligation; (ii) any easement, servitude, restrictive covenant, equity or interest in the nature of an encumbrance, garnishee order, writ of execution, right of set-off, lease, license to use or occupy, assignment of income or monetary Claim; and (iii) any agreement to create any of the foregoing or allow any of the foregoing to exist.

"Environmental Law" means any Applicable Law pertaining to (i) the regulation or protection of employee health or safety, public health or safety, or the indoor or outdoor environment; (ii) the conservation, management, development, control or use of land, natural resources, or wildlife; (iii) the protection or use of surface water or ground water; (iv) the management, manufacture, possession, presence, use, generation, treatment, storage, disposal, transportation, or handling of, or exposure to any Hazardous Material; or (v) pollution (including release of any hazardous substance to air, land, surface water and ground water), including the Comprehensive Environmental Response, Compensation, and Liability Act, as amended by the Superfund Amendments and Reauthorization Act of 1986 (42 U.S.C. §§ 9601 et seq.), the Hazardous Materials Transportation Act (49 U.S.C. §§ 1801 et seq.), the Resource Conservation and Recovery Act, as amended (42 U.S.C. §§ 6901 et seq.), the Toxic Substances Control Act (15 U.S.C. §§ 2601 et seq.), the Clean Water Act (33 U.S.C. §§ 7401 et seq.), the Clean Air Act, as amended (42 U.S.C. §§ 7401 et seq.), the Safe Drinking Water Act (42 U.S.C. §§ 300f et seq.), the Uranium Mill Tailings Radiation Control Act (42 U.S.C. §§ 7901 et seq.), the Federal Insecticide, Fungicide and Rodenticide Act (7 U.S.C. §§ 136 et seq.), all as now or hereafter amended or supplemented, and any regulations promulgated thereunder, and any other similar federal, state, or local statutes, rules and regulations.

"Environmental Liability" has the meaning set forth in Section 10.3.1.

"Facility" means the Mitchell Power Generation Facility consisting of two (2) coal-fired generating units, each having a nominal nameplate capacity of 800 megawatts, and associated plant, equipment and real estate, located in Moundsville, West Virginia, and includes all electrical or thermal devices, and related structures and connections that are located at the Site and used for the production of power and the transportation and handling of fuel for the benefit of the Owners, but excluding the real property and operation known as the Conner Run Fly Ash Impoundment and Dam.

"Facility Agreements" means this Agreement, the Ownership Agreement, all applicable interconnection agreements, fuel supply agreements, coal ash, gypsum and other combustion byproduct disposal or sales agreements, all applicable equipment maintenance agreements in effect or entered into, and as amended, supplemented or modified, from time to time by the Operator or the Owners relating to the Facility, all equipment contracts with regard to warranties and equipment design and specifications, and any other agreement reasonably designated by the Owners as a "Facility Agreement."

"Facility Equipment" has the meaning set forth in Section 13.1.

"Facility Personnel" means those individuals who are employed by Operator or its Affiliates to perform services in respect of the Facility under this Agreement.

"Force Majeure Event" has the meaning set forth in Section 14.6.1.

"Governmental Approval" means any consent, license, approval, exemption, Permit, "no objection certificate" or other authorization of whatever nature that is required to be granted by any Governmental Authority or any third party with respect to the siting, construction, operation, service and maintenance of the Facility in accordance with this Agreement, or otherwise necessary to enable an Owner or Operator to exercise its rights, or observe or perform its obligations, under this Agreement.

"Governmental Authority" means any federal, national, regional, state, municipal or local government authority, tribunal, court, agency, body, board or instrumentality, or any regulatory, administrative or other department, bureau or agency, or any political or other subdivision, department or branch of the foregoing, including any independent system operator, regional transmission organization or electric reliability organization.

"Hazardous Materials" means (a) any petroleum or petroleum products, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation, 1.4 Dioxane, per-and polyfluoroalkyl substances, and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls; (b) any chemicals, materials or substances that are now or hereafter become defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollution," "pollutants," "regulated substances," or words of similar import under Applicable Law; or (c) any other chemical, material, substance or waste declared to be or regulated as hazardous, toxic or polluting material by any Governmental Authority, exposure to which is now or hereafter prohibited, limited or regulated by any Governmental Authority.

"Late Payment Rate" means a rate of interest per annum equal to the lesser of (i) the "prime" rate of interest per annum for corporate loans as published in The Wall Street Journal under "Money Rates" as such rate may be in effect from time to time during the period the delinquent amount remains outstanding plus four (4) percentage points (4%) per annum or (ii) the maximum rate of interest permitted by Applicable Law.

"Lender" means any entity or entities providing financing or refinancing to an Owner under any financing agreements in connection with the construction or permanent financing for the Facility, and their permitted successors and assigns.

"Liabilities" means, collectively, any and all Claims, damages, judgments, losses, obligations, liabilities, actions and causes of action, fees (including reasonable attorneys' fees and disbursements), costs (including court costs), expenses, penalties, fines and sanctions.

"Manuals" means Facility Equipment manuals, system descriptions, system operating instructions, equipment maintenance instructions and pertinent design documentation created by the Persons that constructed the Facility or manufactured its equipment, and the operation and maintenance procedures and Facility systems descriptions, training, safety, chemistry and environmental manuals, together with the documents and schedules described in such manuals.

"NERC" means the North American Electric Reliability Corporation.

"Non-Operator Owner" has the meaning set forth in the preamble to this Agreement.

"Non-Operator Owner Indemnitees" has the meaning set forth in Section 10.1.

"Operating Committee" means the "Operating Committee" as composed from time to time pursuant to and defined in the Ownership Agreement.

"Operating Costs" has the meaning set forth in Section 7.2.1.

"Operator" has the meaning set forth in the preamble to this Agreement.

"Operator Indemnitees" has the meaning set forth in Section 10.2.

"Operator Proprietary Information" has the meaning set forth in Section 13.3.

"Owner" has the meaning set forth in the preamble to this Agreement.

"Ownership Agreement" has the meaning set forth in the recitals to this Agreement.

"Ownership Interest" has the meaning set forth in the Ownership Agreement.

"Party" means a party to this Agreement and "Parties" means, collectively, the parties to this Agreement, unless the context clearly requires a different construction.

"Permit" means any permit, license, consent, approval or certificate that is required or used for the operation or maintenance of the Facility or the performance of any Service and includes Permits required under Environmental Laws.

"Person" means any Party, individual, partnership, corporation, association, limited liability company, business trust, government or political subdivision thereof, governmental agency or other entity.

"Plan" means an annual operating plan adopted or amended pursuant to Section 5.3.

"Plant Manager" means the production/plant manager for the Facility selected in accordance with Section 3.6, Section 8.5 or Section 8.6.

"Project Manager" means the individual appointed in accordance with Section 5.1.

"Prudent Operation and Maintenance Practices" means those practices, methods and acts generally employed in the power generation industry with respect to facilities of similar type, fuel characteristics and geographical location as the Facility, that at the particular time in question, in the exercise of reasonable judgment in light of the facts known at the time the decision in question was being made, would have been expected to accomplish the desired result of such decision consistent with the goals established in a Budget and Plan, and the requirements of Applicable Law, System Operators, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy and expedition. With respect to Operator, Prudent Operation and Maintenance Practices are not limited to the optimum practices, methods or acts to the exclusion of all others, but rather include a spectrum of possible practices, methods or acts commonly employed in the coal-fired power generation industry, including taking reasonable actions to provide a sufficient number of Persons who are available and adequately trained to provide Services at the Facility, and timely perform preventive, routine, and non-routine maintenance and repairs, as exemplified and generally described in Appendix A, subject, in all cases, to the Operator's duties and the limitations on Operator's authority, as set forth in this Agreement and the Ownership Agreement.

["Qualified Replacement Operator" shall mean a Person that:

(i) has operated for a period of at least three (3) years, and continues to operate, coal and/or natural gas power generation facilities with an aggregate electricity output of at least one thousand (1,000) megawatts and at least one of those facilities is a coal power generation facility with an aggregate electricity output of at least three hundred (300) megawatts (or has engaged a third party to operate the Facility who satisfies such operation standards); and

(ii) either has (a) a credit rating of "BBB-" or higher by S&P Global Ratings and "Baa3" or higher by Moody's Investor Service or (b) a tangible net worth of at least $500,000,000 (or has a direct or indirect parent who satisfies such financial standards).]

"Services" has the meaning set forth in Section 3.1.

"Site" means the land on which the Facility is situated.

"Standards of Performance" means the standards for Operator's performance of the Services set forth in Section 3.3.

"System Operator" means any Person or regional transmission organization, such as PJM Interconnection, L.L.C., supervising the collective transmission or generation facilities of the power region in which the Facility is located that is charged with coordination of market transactions, system-wide transmission planning and network reliability.

"Term" means the initial term together with any extensions.

"Termination Transition Period" has the meaning set forth in Section 8.5.1.

"WPCo" has the meaning set forth in the preamble to this Agreement.

"Year" means the calendar year. With respect to the Year in which the Effective Date occurs, a Year will be deemed to begin on the Effective Date and end on December 31st of such Year. If this Agreement terminates, the final Year will be deemed to end on the date that termination occurs.

## ARTICLE III - RESPONSIBILITIES OF OPERATOR

3.1 Provision of Services. Operator shall operate and maintain the Facility and perform other duties as set forth in this Agreement and as directed by the Owners pursuant to the Ownership Agreement, including performing and, as applicable, contracting for the benefit of the Owners with suppliers and service providers to perform, the services set forth on Appendix A (collectively, the "Services") and agrees to be responsible for the day-to-day operation and maintenance of the Facility.

3.2 Procurement.

3.2.1 Operator shall sign contracts and purchase orders for goods and services to be delivered to the Facility in the name of Operator as agent for the Owners, and shall not contract in the name of the Non-Operator Owner without the Non-Operator Owner's prior written consent. Operator acknowledges that such contracts and purchase orders are for the benefit of the Owners and the Facility. Operator shall endeavor to negotiate with vendors from standard terms and conditions, including reasonable warranties for the benefit of the Owners.

3.2.2 The Non-Operator Owner shall use commercially reasonable efforts to obtain, promptly following the Effective Date, any and all consents of third parties required to assign, transfer or convey to Operator any contracts or purchase orders for goods and services (including fuel supply and transportation) to be delivered to or used by the Facility that are in the name of the Non-Operator Owner as a result of the Non-Operator Owner having served as the Operator prior to the Effective Date, which are reasonably required to be transferred to Operator for the performance of the Services. To the extent that, notwithstanding its commercially reasonable efforts, the Non-Operator Owner is unable to obtain any such required consent effective as of the Effective Date, and as a result thereof Operator shall be prevented by such third party from receiving the rights and benefits with respect to any such contract or purchase order intended to be transferred hereunder, or if any attempted assignment would adversely affect the rights of the Non-Operator Owner thereunder so that Operator would not in fact receive all such rights or the Non-Operator Owner would forfeit or otherwise lose the benefit of rights that the Non-Operator Owner is entitled to retain, the Non-Operator Owner and Operator shall cooperate to implement any lawful and commercially reasonable arrangement as the Non-Operator Owner and Operator shall agree, under which Operator would, to the extent practicable, obtain the claims, rights and benefits under such contract or purchase order and assume the burdens and obligations with respect thereto, including by the Non-Operator Owner subcontracting, sublicensing, subleasing, delegating or granting a limited power of attorney or similar appointment as agent to Operator to administer such contracts or purchase orders; provided, however, that the Non-Operator Owner and WPCo shall each bear its respective share of the costs and expenses under any such contract or purchase order in accordance with this Agreement and the Ownership Agreement. The Non-Operator Owner and Operator shall continue to cooperate to assign, transfer or convey to Operator any such contract or purchase order that remain held by the Non-Operator Owner and to otherwise arrange for Operator to directly contract with the applicable third party for any renewal contract or purchase upon the expiration or termination of any such contract or purchase order.

3.3 Standards for Performance of the Services. Operator shall perform the Services in accordance with (i) the Manuals, (ii) the applicable Budget and Plan, (iii) Applicable Laws, (iv) Prudent Operation and Maintenance Practices, (v) insurer requirements delivered to Operator by the Owners in writing, (vi) the requirements in the Facility Agreements (vii) this Agreement; and (viii) as directed by the Owners pursuant to the Ownership Agreement. Subject to the other provisions of this Agreement, Operator shall perform the Services and other obligations under this Agreement in a manner consistent with the Operating Committee's directions. The Parties acknowledge and agree that, subject to Operator's compliance with the Standards of Performance, Operator shall have no liability for acting or refraining to act in accordance with the directions of the Operating Committee, except to the extent caused by Operator's gross negligence, willful misconduct, fraud, willful violation of any Applicable Law, willful breach of this Agreement or the Ownership Agreement or other willful misconduct.

3.4 Dispatch. Operator shall use commercially reasonable efforts to comply with any applicable dispatch instructions of the System Operator and, to the extent applicable, the directions of the Operating Committee or other Person identified by an Owner in writing to Operator as being authorized to provide dispatch instructions made in accordance with the Ownership Agreement. Operator shall give the Operating Committee notice as soon as practicable of any inability of the Facility to make the requisite deliveries of energy, capacity or ancillary services and of Operator's plan to restore operation of the Facility. In the case of any interruption, curtailment or reduction in (i) supplies of fuel or (ii) acceptance of energy, capacity or ancillary services by the System Operator or in the case of any other dispatch constraint imposed on the Facility, Operator shall notify the Non-Operator Owner as soon as practicable. Upon removal of the constraint, Operator shall use its commercially reasonable efforts to restore the availability of the Facility for dispatch consistent with applicable dispatch instructions of the System Operator and, to the extent applicable, the directions of the Operating Committee or other Person identified by an Owner in writing to Operator as being authorized to provide dispatch instructions made in accordance with the Ownership Agreement.

3.5 Licenses and Permits.

3.5.1 General. Operator shall review all Applicable Laws containing or establishing compliance requirements in connection with the operation and maintenance and Decommissioning of the Facility and shall use commercially reasonable efforts to obtain and maintain, for the benefit of both Owners, all Permits required by Applicable Law for the ownership, operation, maintenance and Decommissioning of the Facility and for Operator's performance of the Services, and shall (i) from time to time, notify the Operating Committee if Operator believes that a Permit is required by Applicable Law to be obtained by an Owner in its name in order to allow Operator to perform the Services and assist each Owner, at each Owner's written request and such Owner's sole cost and expense, in securing and complying with, as appropriate, all necessary Permits (and renewals of the same) which are required to be in an Owner's name, including those relating to air emissions, boiler operation, water usage, septic system operation, wastewater discharge, chemical and other waste (including Hazardous Materials) storage and disposal, emissions testing and safety, and (ii) initiate and maintain precautions and procedures reasonably necessary to comply with Applicable Laws. Any Permit held solely in the name of Operator shall, to the extent necessary for the other Owner's compliance with Applicable Law in its role as an Owner, be held by Operator for the benefit of both Owners. Any Permit held solely in the name of the Non-Operator Owner shall, to the extent necessary and consistent with Applicable Laws, be made available for the use of the Operator for the benefit of the Owners and, if reasonably necessary to facilitate Operator's operation and maintenance or Decommissioning of the Facility, the Non-Operator Owner shall cooperate with Operator to effect an assignment or other transfer of such Permit to Operator or otherwise submit such Permit modifications or updating information as necessary to reflect the role of Operator with respect to such Permit.

3.5.2 NERC Compliance. Operator (or an Affiliate thereof) shall register with NERC as the "Generator Owner" and "Generator Operator" for the Facility in accordance with 18 C.F.R. § 39.2(c) effective from and after [the Effective Date][1]. On and after [the Effective Date], Operator shall, or shall cause its applicable Affiliate to, (i) maintain compliance with all NERC reliability standards applicable to the Facility and all NERC rules applicable to Operator as Generator Owner and Generator Operator for the Facility in accordance with 18 C.F.R. § 39.2(b), including any actions related to mitigation and compliance enhancement required or implemented thereunder; (ii) provide notice to the Operating Committee promptly following the determination by Operator of any reportable physical or cyber security incident under the NERC reliability standards or other Applicable Law; (iii) maintain and provide documentation and maintenance records to the Operating Committee regarding any operation, testing, maintenance or faults of any generation protection relays, gen-tie relays or any other equipment necessary to fulfill Operator's

[1] **Note**: Subject to modification if registration cannot be effective as of the Effective Date.

or its applicable Affiliate's obligations as the Generator Owner or Generator Operator for the Facility; and (iv) provide to the Non-Operator Owner upon written request any other information, documentation and support reasonably necessary for Operator or its applicable Affiliate to demonstrate compliance with the NERC reliability standards. To the extent that any fine or sanction is imposed in respect of the performance of Operator's obligations under this Section 3.5.2 pursuant to Section 215(c) of the Federal Power Act, any cost related thereto shall be a included as an Operating Cost, to the extent permitted by Applicable Law.

3.6 Personnel Matters. Subject to Sections 8.5 and 8.6, and as otherwise set forth in this Section 3.6, Operator shall be responsible for determining the working hours, rates of compensation and all other matters relating to the employment of Operator's Facility Personnel, including the designation or appointment of the Plant Manager, in its reasonable judgment and in accordance with Non-Operator Owner's and its Affiliates' past practices in the ordinary course of its business during the time it served as operator of the Facility, and shall retain sole authority, control and responsibility with respect to its employment policies. Operator shall submit for the Operating Committee's approval the staffing requirements for the Facility on an annual basis. If Operator intends to select a new Plant Manager, or if the individual serving as Plant Manager ceases to be the Plant Manager, Operator shall provide prompt written notice to the Non-Operator Owner of the selection of a substitute Plant Manager. Facility Personnel shall be qualified and experienced in the duties to which they are assigned. Operator shall, upon the reasonable written request of the Non-Operator Owner, for cause (as documented in reasonable detail in any such written request), use commercially reasonable efforts to, as promptly as practicable under the circumstances and subject to any applicable collective bargaining agreements, remove from the Site and the Facility workforce, the services of any employee or other individual, subject to Operator's confirmation that such cause exists.

3.7 No Liens or Encumbrances. Operator shall use commercially reasonable efforts to keep and maintain the Facility free and clear of all liens and Encumbrances resulting from the failure by Operator to perform the Services or the personal debts and obligations of Operator unrelated to its ownership interest in the Facility.

3.8 Emergency Action. In the event of an emergency affecting the safety, health or protection of, or otherwise endangering, any Person, property or the environment located at or about the Facility (an "Emergency"), Operator shall take prompt action in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate any imminent damage, injury or loss threatened by such Emergency, and shall notify the Non-Operator Owner of such Emergency and Operator's response as soon as practical under the circumstances and in no event later than forty-eight (48) business hours after Operator becomes aware of such event. To the extent Operator procures goods and services as necessary to respond to an Emergency, reasonable and documented out of pocket costs in respect thereof shall be treated as Operating Costs.

## ARTICLE IV - OBLIGATIONS, RIGHTS AND REPRESENTATIVES OF EACH OWNER

4.1 General. Each Owner expressly reserves the exclusive authority to make, and shall make, such business and strategic decisions as it deems appropriate from time to time in reference to the operation and maintenance of the Facility in accordance with the Ownership Agreement.

Upon request from Operator, the Non-Operator Owner shall promptly furnish or cause to be furnished to Operator, at the Non-Operator Owner's expense, the information, access, materials, instructions and other items described in this Article IV that are in the possession or control of the Non-Operator Owner and which are reasonably necessary for performance of the Services by Operator and not otherwise available to Operator. All such items will be made available at such times and in such manner as may be reasonably required for the expeditious and orderly performance of the Services by Operator.

4.2 Information. Subject to the Standards of Performance, Operator shall be entitled to rely upon any information provided by the Non-Operator Owner or any other party to the Facility Agreements in the performance of the Services.

4.3 Access to Facility. Each Owner shall provide Operator and Operator's contractors, vendors, suppliers, employees and agents and Facility Agreement counterparties, to the extent applicable, reasonable access to and use of the Facility and the Site and to such Owner's records and data at the Facility and, in the case of the Non-Operator Owner, reasonably available to the Non-Operator Owner or in the Non-Operator Owner's possession and reasonably necessary for the performance of Services by Operator under this Agreement.

4.4 Instructions, Approvals, etc. Each Owner shall provide or cause to be provided (including through action of the Operating Committee) to Operator all instructions Operator is required to obtain in accordance with this Agreement. Without limiting the provisions of Section 3.2.2, each Owner shall reasonably cooperate to make available or cause to be available to Operator the benefits of all assets (including Permits and contracts relating to the Facility) held in the name of such Owner, as reasonably required for the operation of the Facility. Each Owner shall not direct Operator to take any action inconsistent with Applicable Law or otherwise adversely affecting the safety, health or protection of any person, or property or the environment located at or about the Facility.

## ARTICLE V - REPRESENTATIVES, BUDGETS AND REPORTS

5.1 Representatives of Operator. On or as soon as practical after the Effective Date, Operator shall appoint a Project Manager who shall be authorized to represent Operator with each Owner and the Operating Committee concerning Operator's performance of the Services. The Project Manager may be the same individual as the Plant Manager. Operator shall be responsible for all communications, directions, requests and decisions made by its Project Manager at its direction. Operator shall notify the Non-Operator Owner in writing upon the appointment of its Project Manager, and of any successors. The Project Manager has no authority to modify, amend or terminate this Agreement or, absent written notice by Operator to the contrary, to enter into any other agreement on behalf of Operator other than as provided herein.

5.2 Representatives of Owner; Operating Committee. The Operating Representative of each Owner (pursuant to and as defined in the Ownership Agreement) shall be authorized and empowered to act for and on behalf of such Owner on all matters requiring the consent, approval or other action of an Owner pursuant to this Agreement. Each Owner shall notify Operator and the other Operating Representative in writing upon the appointment of its Operating Representative, and of any successors. Any provision of this Agreement requiring the consent, approval, or similar act of the Operating Committee shall mean the consent, approval, or similar act of the Operating Committee acting in accordance with the terms of the Ownership Agreement.

5.3 Plans and Budgets.

5.3.1 Adoption.

5.3.1.1. Budgets. The initial Budget and Plan for the first Year following the Effective Date is attached as Appendix B hereto. No later than ninety (90) days prior to each operating Year, Operator shall deliver to the Operating Committee for the Operating Committee's review, revision if applicable and approval (i) a proposed annual operating budget, (ii) any proposed amendments to the annual capital budget, (iii) an annual operating plan and (iv) a six (6) Year future forecast of operating and capital expenses. Each such proposed budget, plan and forecast shall contain such detail and supporting documentation as reasonably necessary or reasonably requested for the Operating Committee's review, and Operator shall provide all such additional information and supporting documentation as may be reasonably requested by the Operating Committee and as required by the Ownership Agreement. The Operating Committee shall review and provide modifications to each such proposed budget, plan and forecast and Operator shall cooperate to revise each such proposed budget and plan to receive the Operating Committee's approval of same by December 1 of each Year. Each Budget and Plan as approved by the Operating Committee or otherwise deemed implemented pursuant to the Ownership Agreement shall remain in effect in accordance with the Ownership Agreement. Operator and the Non-Operator Owner by mutual agreement may modify the process and procedures set forth in this Section 5.3.1.

5.3.1.2. Amendments. If either the Non-Operator Owner or Operator becomes aware of facts or circumstances that it believes necessitate a change to a Budget or Plan, that Party shall promptly notify the other Party in writing, specifying the impact upon the Budget and the reasons for the change. The Project Manager shall then discuss appropriate amendments to the Budget with the Operating Committee.

5.3.1.3. Failure to Agree. Operator acknowledges that the Owners retain ultimate authority with respect to expenses incurred for the Facility. Accordingly, Operator shall accept each Budget as determined in accordance with the Ownership Agreement. To the extent that the Operating Committee limits funds for Operating Costs, Operator shall be relieved from performing only those specific Services that would result in the incurrence of such non-reimbursable Operating Costs.

5.3.2 Limitations on Variation from Budget. Except as otherwise permitted in response to an Emergency in accordance with Section 3.8, Operator shall obtain the Operating Committee's written approval (i) for any expenditures resulting in cumulative budget overruns exceeding ten percent (10%) in the aggregate in any Year with respect to either the operating Budget or capital expense Budget, or (ii) for any unbudgeted expenditure or capital project having a projected cost of more than $100,000.

5.4 Availability of Operating Data and Records. Operator shall deliver Facility data recorded, prepared or maintained by Operator to the Operating Committee: (i) as necessary or reasonably requested by an Owner to assist each Owner in complying with requirements of Governmental Authorities, Permits and Facility Agreements; or (ii) upon request by the Non-Operator Owner, in each case as soon as reasonably practicable but in any event within ten (10) Business Days following such request.

5.5 Litigation and Permit Lapses. Promptly upon obtaining actual knowledge thereof, either Party shall submit prompt written notice to the other Party of the following, to the extent relating to the Facility or the Services or agreements relating to either the Facility or the Services: (i) any litigation, Claims or actions filed, including by, against or with any Governmental Authority; (ii) any actual refusal to grant, renew or extend, or any action filed with respect to the granting, renewal or extension of, any Permit; (iii) all penalties or notices of violation issued or asserted by any Governmental Authority; (iv) any dispute with any Governmental Authority that may affect the Facility in any material respect; and (v) with respect to the matters identified in items (i), (ii), (iii) or (iv), any material threats of such matters. Upon Non-Operator Owner's request, Operator shall provide any documentation related to any of the foregoing.

5.6 Other Information. Operator shall promptly submit to the Non-Operator Owner any material information concerning new or significant aspects of the Facility operations and, upon the Non-Operator Owner's request, shall promptly submit any other information concerning the Facility or the Services.

5.7 Records Maintenance and Retention. Operator shall maintain all records, reports, documents and data, including all data retrievable from an electronic data storage source, for the Facility in accordance with Applicable Law and shall retain and preserve all such records, reports, documents and data created in connection with the operation and maintenance of the Facility, in accordance with Applicable Law, provided that Operator shall notify the Non-Operator Owner in writing at least sixty (60) days prior to the destruction or other disposition of any record, report, document or data. If the Non-Operator Owner gives written notice to Operator prior to the expiration of the 60-day period, Operator shall maintain custody of such material until the earlier of (i) such time as the Non-Operator Owner notifies Operator to dispose of such material and (ii) seven (7) Years. If the Non-Operator Owner does not provide written notice to Operator prior to the expiration of the 60- day period, Operator may destroy or dispose of such material and shall provide the Non-Operator Owner with a certificate confirming such destruction or disposition.

## ARTICLE VI - LIMITATIONS ON AUTHORITY

6.1 Limitations on Authority. Operator has no authority to make policies or decisions with respect to the overall operation or maintenance of the Facility as a commercial enterprise pursuant to the terms of this Agreement. The Owners, acting through the Operating Committee and pursuant to the terms of the Ownership Agreement, shall determine all such matters. Notwithstanding any provision in this Agreement to the contrary, unless previously approved in a Budget and Plan or otherwise approved in writing by the Operating Committee, in connection with Operator's provision of Services hereunder, Operator is prohibited from doing any of the following (and shall not permit any of its agents, Affiliates, or representatives to do any of the following):

6.1.1 Dispose of Assets. Selling, leasing, pledging, mortgaging, granting a security interest in, encumbering, conveying, or making any license, exchange or other transfer or disposition of all or any portion of the Facility, the Site or any other property or assets of the Owners, including any property or assets purchased by Operator, the cost of which is an Operating Cost;

6.1.2 Make Expenditures. Making any expenditure or acquiring, on an Operating Cost basis, any goods or services from third parties, except in conformity with a Budget or as otherwise permitted under Section 5.3.2 or as authorized by the Operating Committee; provided, however, that in the event of an Emergency, Operator, without approval from the Owners, is authorized to take all reasonable actions in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate such threatened damage, injury or loss in accordance with Section 3.8;

6.1.3 Take Other Actions. Taking or agreeing to take any other action or actions the decision for which is reserved exclusively for the Operating Committee pursuant to the Ownership Agreement; provided, however, that in the event of an Emergency, Operator, without approval from the Operating Committee, is authorized to take all reasonable actions in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate such threatened damage, injury or loss in accordance with Section 3.8;

6.1.4 Act Regarding Lawsuits and Settlements. Settling, compromising, assigning, pledging, transferring, releasing or consenting to the compromise, assignment, pledge, transfer or release of, any material Claim, suit, debt, demand or judgment against or due by any Owner or Operator, the cost of which would be an Operating Cost hereunder, or submitting any such Claim, dispute or controversy to arbitration or judicial process, or stipulating in respect thereof to a judgment, or consent to the same; provided, however, that such prohibition shall not apply to, nor shall it be construed as a release or waiver of, any of Operator's rights or obligations pursuant to this Agreement or any other agreement between the Parties; or

6.1.5 Pursue Transactions. Engaging in any other transaction on behalf of the any Owner that is not permitted under this Agreement.

## ARTICLE VII - COMPENSATION AND PAYMENT

7.1 General. The Non-Operator Owner shall pay Operator, and WPCo shall bear directly in its capacity as an Owner, its allocated share in accordance with the Ownership Agreement of all Operating Costs, all as further described below. All Operating Costs shall initially be paid for by Operator (except as otherwise provided in this Agreement) and subsequently invoiced monthly in arrears as more fully set forth in this Article VII.

7.2 Costs.

7.2.1 Operating Costs. Subject to the Ownership Agreement and the limitations on expenditures set forth elsewhere in this Agreement (including Section 5.3), the Non-Operator Owner shall reimburse Operator for its allocated share in accordance with the Ownership Agreement of the fully distributed costs incurred (whether paid or accrued) in the provision of Services (which shall be allocated consistent with Non-Operator Owner's and its Affiliates past practices in the ordinary course of business during the time it served as operator of the Facility and in any event in accordance with the Cost Allocation Manual with respect to costs incurred by Affiliates of Operator), including for labor, goods, services, capital expenditures, overhead, cost of capital, Taxes (other than income or franchise taxes), Permits and bonds (the "Operating Costs"), in each case invoiced in a manner consistent with the example invoice worksheets attached hereto as Appendix C, which shall include such costs with respect to: (i) equipment, material, supplies and other consumables, spare parts, replacement components, tools, office equipment, computer equipment, software, information technology and supplies acquired for use at the Facility; (ii) fuel supply and transportation; (iii) costs associated with special training of Facility Personnel and associated travel and living expenses; (iv) amounts paid under subcontracts, purchase orders and agreements; (v) fees for Permits required to be held by Operator; (vi) community relations and labor relations activities; and (vii) Operator's cost of Facility Personnel (and the allocable portion of other employees of Operator and its Affiliates attributable to performing the Services) wages, salaries, overtime, employee bonus, customary or required severance payments, unemployment insurance, long-term disability insurance, short term disability payments, sick leave, payroll taxes imposed on wages and benefits, worker's compensation costs and holidays, vacations, group medical, dental and life insurance, defined contribution retirement plans and other employee benefits; (viii) costs of third-party advisors, consultants, attorneys, accountants and contractors retained and managed by Operator in support of, and allocable to, the Services; (ix) a reasonably allocable portion of the cost of the insurance maintained by Operator in accordance with Section 9.1 on account of its Operator role; (x) reasonable costs incurred in response to an Emergency; and (xi) any other activity that Operator is required or expressly requested in writing by the Owners to perform under this Agreement for the benefit of the Facility or that is approved in a Budget or by the Operating Committee pursuant to the terms of this Agreement.

7.2.2 Invoicing. On or before the twenty-fifth (25$^{th}$) day of each calendar month during the Term, Operator shall submit invoices to the Non-Operator Owner in form and substance reasonably similar to that attached hereto as Appendix C for Operating Costs incurred during the preceding calendar month (as well as any such costs for any prior period that were not previously invoiced). If any contract or purchase order intended to be assigned, transferred or conveyed to Operator remains held by the Non-Operator Owner as described in Section 3.2.2 and the Non-Operator Owner directly pays costs thereunder for the benefit of the Owners, the invoice submitted by Operator shall net WPCo's allocated share in accordance with the Ownership Agreement of any such costs paid by the Non-Operator Owner for the benefit of the Owners. The Non-Operator Owner shall make payment to Operator of its allocated share in accordance with the Ownership Agreement of the invoiced amount no later than the Due Date. For the avoidance of doubt, WPCo, in its capacity as an Owner, shall bear directly its allocated share in accordance with the Ownership Agreement of such Operating Costs.

7.3 Cost Audit. The Non-Operator Owner shall be entitled to conduct an audit, or to delegate a representative to audit, at its sole cost and expense and review of Operator's books and records with respect to all Operating Costs and performance of the Services together with any supporting documentation for a period of one (1) Year from and after the date of the audited payment. If, pursuant to such audit and review, it is agreed that any amount previously paid by Operator or by an Owner was not properly incurred as an Operating Cost or an adjustment of any such cost is required, Operator shall credit to the Non-Operator Owner or Operator, as applicable, its allocated share in accordance with the Ownership Agreement of such amount in the next succeeding invoice or promptly paid in cash if there shall not be further invoices issued.

7.4 Late Payment Rate. To the extent a Party fails to pay any amount required to be paid under this Agreement by the Due Date, the unpaid amount shall accrue interest each day at the Late Payment Rate from the Due Date until such amount (plus accrued interest) is paid by the applicable Party in full. In the event any paid amounts are disputed by a Party in good faith and such dispute is resolved (including if applicable in accordance with the procedures set forth in Section 14.7) in the favor of such Party, then the applicable other Party shall repay to such Party such overpaid amount plus interest thereon accrued each day at the Late Payment Rate from payment by such Party until such amount (plus accrued interest) is repaid in full to such Party by the applicable other Party.

## ARTICLE VIII - TERM

8.1 Term. The Term of this Agreement shall commence on the Effective Date and, subject to approval or acceptance of termination by FERC or other Governmental Authority to the extent required, shall end on the date of termination of the Ownership Agreement (the "Term"). Notwithstanding the foregoing, this Agreement and the Term is subject to earlier termination pursuant to Sections 8.2 and 8.3.

8.2 Termination by the Non-Operator Owner for Cause. The Non-Operator Owner shall be permitted to terminate this Agreement upon written notice to Operator if any of the following events occur: (i) the Bankruptcy of Operator; (ii) a payment default by Operator (other than a disputed payment) that Operator fails to cure within ten (10) Business Days after Operator has received written notice of such default; (iii) Operator incurs liability to the Owners equal to the liability limit set forth in Section 11.2 for any two Years during the Term (provided that written notice of termination must be delivered to Operator no later than ninety (90) days after the end of the second of such two Years), or (iv) a material default by Operator in the performance of its obligations under this Agreement, including any default that has, or is reasonably expected to have, a material adverse effect on the operations, maintenance or performance of the Facility and Operator has failed to cure such default within sixty (60) days of written notice of such failure; provided, that if it is not possible to cure such breach within sixty (60) days of receipt of such notice of failure, Operator (A) fails to commence to cure the breach within such sixty (60) day period, (B) thereafter fails to continue diligent efforts to complete the cure as soon as reasonably possible, or (C) fails to complete the cure within ninety (90) days of receipt of such notice of failure. In addition, Non-Operator Owner shall have the option to terminate this Agreement for convenience upon ninety (90) days written notice to Operator delivered no later than ninety (90) days after the occurrence of any transfer, assignment, sale or other disposition (including any transfers, assignments, sales or other dispositions in connection with a foreclosure or an exercise of remedies by the Financing Parties) that results in WPCo's Ownership Interest no longer being owned directly or indirectly by AEP or an Affiliate thereof, except in the case of an transfer, assignment, sale or other disposition to a successor Operator that is a Qualified Replacement Operator in compliance with the terms of this Agreement and the Ownership Agreement.

8.3 Termination by Operator. Operator shall be permitted to terminate this Agreement upon written notice to the Non-Operator Owner if any of the following events occur: (i) a payment default by the Non-Operator Owner (other than a disputed payment) that is not cured within thirty (30) days after the Due Date for any invoice; (ii) the Bankruptcy of the Non-Operator Owner; or (ii) a default by the Non-Operator Owner of any other obligation under this Agreement that has a material adverse effect on Operator's ability to perform the Services and that the Non-Operator Owner has failed to cure or make substantial progress in the reasonable opinion of Operator toward curing within ninety (90) days of written notice by Operator to the Non-Operator Owner of such failure. As soon as practicable after all cost information is gathered following termination, Operator shall invoice the Non-Operator Owner for its allocated share in accordance with the Ownership Agreement for Services rendered by Operator through the termination date, including all Operating Costs incurred through the date of termination but not paid.

8.4 Transfer of Facility Custody. Upon expiration or termination of this Agreement, Operator shall leave at the Facility all documents and records, tools, supplies, spare parts, safety equipment, Manuals, and any other items furnished on an Operating Cost basis, all of which shall remain the property of the Owners without additional charge. Operator shall execute all documents and take all other reasonable steps as may be reasonably requested by the Non-Operator Owner to assign to and vest in a replacement provider of Services all of its pro-rata rights, benefits, interests and title in connection with any subcontracts Operator executed in its own name for the benefit of the Facility and the Owners.

8.5 Services Upon Termination.

8.5.1 Upon notice of termination of this Agreement by either Operator or the Non-Operator Owner, unless the Non-Operator Owner is then in payment default such that Operator would have the right to terminate this Agreement pursuant to Section 8.3(i), the Non-Operator Owner shall have the right to specify a period of transition of no longer than nine (9) months (the "Termination Transition Period") during which Operator shall: (i) continue to provide Services at the Facility in accordance with this Agreement; (ii) cooperate with the Non-Operator Owner in planning and implementing a transition to any replacement provider of Services; (iii) use its commercially reasonable efforts to minimize disruption of Facility operations in connection with such transition activities; (iv) make all requisite regulatory filings as promptly upon commencement of the Termination Transition Period, subject to cooperation of the Parties; (v) transfer all Permits, licenses, registrations, approvals and contracts to the Non-Operator Owner or such replacement operator, in each case, as requested by the Non-Operator Owner; and (vi) take all actions incidental thereto and as reasonably requested by the Non-Operator Owner. The provisions of Article VII shall continue to apply during the Termination Transition Period. To facilitate employee transfer, Operator shall permit the replacement service provider and the Non-Operator Owner to interview such Facility Personnel for potential positions with such replacement operator in a manner and at times that do not interfere with Operator's responsibility to perform the Services. If Operator or one of its Affiliates continues to own a portion of the Facility, Operator shall, or shall cause its Affiliates to, reasonably cooperate to allow a successor operator to operate the Facility after the termination of this Agreement, including by granting access rights and executing other instruments as may be reasonably requested by the Non-Operator Owner and any replacement operator.

8.5.2 Any modifications to the ownership and operation of the Facility, including any termination of this Agreement, shall be subject to any required regulatory or administrative filings and approvals.

8.6 Plant Manager Replacement. Upon (i) commencement of the Termination Transition Period or (ii) the occurrence of any of the conditions described in Section 8.2, the Non-Operator Owner may designate a qualified individual with significant experience as a project manager or similar senior operating role in respect of the management and operation of large coal-fired generation facilities with similar operating characteristics as the Facility to replace the existing Plant Manager and who shall upon such appointment be the Plant Manager.

## ARTICLE IX - INSURANCE

9.1 Operator Insurance Requirements.

9.1.1 Commencing with the performance of the Services hereunder, and continuing until the termination of this Agreement, Operator (and any tier subcontractors) shall maintain or cause to be maintained occurrence form (if written on a claims -made policy form, be maintained with a retroactive date that is prior to this Agreement Effective Date for a period of at least three (3) Years following the last Year in which such policy provides coverage under the terms of this Agreement) insurance policies as follows: (i) Workers' Compensation in accordance with the statutory requirements of the state in which the Services are performed and Employer's Liability Insurance of not less than one million Dollars ($1,000,000) each accident/employee/disease; (ii) Commercial General Liability Insurance having a limit of at least one million Dollars ($1,000,000) per occurrence/two million Dollars ($2,000,000) in the aggregate for contractual liability, personal injury, bodily injury to or death of Persons, and/or loss of use or damage to property, including but not limited to products and completed operations liability (which shall continue for at least three (3) Years after completion), premises and operations liability and explosion, collapse, and underground hazard coverage; (iii) Commercial/Business Automobile Liability Insurance (including owned (if any), non-owned or hired autos) having a limit of at least one million Dollars ($1,000,000) each accident for bodily injury, death, property damage and contractual liability and no fellow employee exclusion; (iv) Umbrella/Excess Liability insurance with limits of at least twenty-four million Dollars ($24,000,000) per occurrence and follow form of the underlying Employer's Liability, Commercial General Liability and Auto Liability insurance, and provide at least the same scope of coverages thereunder; (v) coverage for sudden/accidental occurrences for bodily injury, property damage, environmental damage, cleanup costs and defense with a minimum of one million Dollars ($1,000,000) per occurrence; and (vi) "all-risk" or its equivalent property insurance providing coverage risks of physical damage to the Facility or Facility Equipment in an amount in accordance with Good Utility Practice.

9.1.2 Unless otherwise determined by the Operating Committee that the Operator should purchase capacity insurance on behalf of both Owners, Operator (including in its capacity as an Owner) and Non-Operator Owner may each procure individually, in proportion to their Ownership Interests, PJM Interconnection, L.L.C. capacity performance insurance on terms and conditions, and placed with insurance companies, reasonably acceptable to the Operator or such Owner, as applicable. Operator shall make such certifications relating to the operation, maintenance and condition of the Facility from time to time during the Term as may be reasonably necessary in connection with the procurement or maintenance of such insurance coverage by Operator and the Non-Operator Owner and any other insurance policies of either Owner that may relate to coverage pertaining to or affecting an Owner's Ownership Interest.

9.2 Form and Content. All insurance policies provided and maintained by Operator and each subcontractor shall: (i) except with respect to insurance policies issued by any "captive" insurer of Operator or its Affiliates, be underwritten by insurers that are rated A.M. Best "A- VII" or higher; (ii) specifically include the Non-Operator Owner and its directors, officers, employees, affiliates, subcontractors, and joint owners of any facilities as additional insureds for their liability arising out of the acts or omissions of Operator, including for completed operations, with respect to Operator's acts, omissions, services, products or operations, whether in whole or in part, excluding, however, for Workers' Compensation/Employer's Liability insurance, Pollution Legal Liability insurance, and "all-risk" property insurance; (iii) be endorsed to provide, where permitted by law, waiver of any rights of subrogation against an Owner and its directors, officers, employees, affiliates and subcontractors, and joint owners of any facilities; (iv) provide that such policies and additional insured provisions are primary with respect to the acts, omissions, services, products or operations of Operator or its subcontractors, to the extent of Operator's negligence, (v) contain standard separation of insured and severability of interest provisions except with respect to the limits of the insurer's liability; and (vii) not have any cross-liability exclusion, or any similar exclusion that excludes coverage for Claims brought by additional insureds under the policy against another insured under the policy; Any deductibles or retentions shall be the sole responsibility of Operator and its subcontractors. Evidence of such coverage shall be provided in the form of Operator's certificate of insurance furnished to the Non-Operator Owner prior to the Effective Date, upon any policy replacement or renewal and upon the Non-Operator Owner's request. Operator shall provide at least thirty (30) days' prior written notice to the Non-Operator Owner prior to cancellation of any policy (or ten (10) days' notice in the case of non-payment of premium).

## ARTICLE X - INDEMNIFICATION

10.1 Operator Indemnification. Subject to the limitations of liability in Section 11.1, Operator shall indemnify and hold harmless the Non-Operator Owner and its Affiliates, and their respective officers, directors, employees, managers, members, agents and representatives (collectively, the "Non-Operator Owner Indemnitees"), from and against, and no Non-Operator Owner Indemnitee shall be responsible for any and all Liabilities incurred, assessed, sustained or suffered by any Non-Operator Owner Indemnitee to the extent caused by Operator's gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law, or willful breach of this Agreement. Any Liabilities paid by Operator pursuant to its indemnity obligation under this Section 10.1 shall in no event be considered Operating Costs hereunder.

10.2 Owner Indemnification. Subject to the limitations of liability in Section 11.1, each Owner shall, severally with respect to its proportionate share in respect of its Ownership Interest and not jointly, indemnify and hold harmless Operator and its Affiliates, and their respective officers, directors, employees, agents and representatives (collectively, the "Operator Indemnitees"), from and against, and no Operator Indemnitee shall have responsibility for, any and all Liabilities to a third party incurred, assessed, sustained or suffered by or against any Operator Indemnitee arising from or relating to Operator's performance of the Services under this

Agreement, except to the extent caused by Operator's gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law, or willful breach of this Agreement; provided, however, that the Liabilities for which Non-Operator Owner is obligated to indemnify any Operator Indemnitees under this Section 10.2 shall not in any event include any Liabilities for which WPCo is obligated to indemnify Non-Operator Owner (and/or its Affiliates) in any agreement among the Owners (and/or their Affiliates) and AEP (and/or its Affiliates) pertaining to the allocation of emission limitations associated with the Facility. For the avoidance of doubt, WPCo, in its capacity as an Owner of the Facility, shall bear directly its proportionate share of Liabilities under this Section 10.2 in respect of its Ownership Interest.

10.3 Environmental Indemnification.

10.3.1 Owner Indemnity for Environmental Liabilities. Subject to the limitations of liability in Section 11.1, and without in any way limiting the provisions of Section 10.3.2, each Owner shall, severally with respect to its proportionate share in respect of its Ownership Interest and not jointly, indemnify and hold harmless the Operator Indemnitees, from and against, and no Operator Indemnitees shall have responsibility for, any and all Liabilities, including all civil and criminal fines or penalties and other costs and expenses incurred, assessed, sustained or suffered by or against any Operator Indemnitees, as applicable, as a result of or in connection with any matters governed by Environmental Laws directly or indirectly related to or arising out of (i) the design, permitting or construction of the Facility or the condition of the Site, and any adjacent parcels; (ii) the operation, maintenance, ownership, control or use of the Facility or otherwise related to the Facility; and (iii) the offsite transportation, treatment or disposal of all wastes generated at the Facility and any properties included within or adjacent to the Site, whether occurring before or after the Effective Date (collectively, "Environmental Liabilities"), including any Environmental Liabilities arising out of the actual or alleged existence, generation, use, emission, collection, treatment, storage, transportation, disposal, recovery, removal, release, discharge or dispersal of Hazardous Materials, but excluding Operator Environmental Liabilities; provided, however, that the Environmental Liabilities for which any Owner is obligated to indemnify any Operator Indemnitees under this Section 10.3.1 shall not in any event include any Operator Environmental Liabilities for which Operator is liable under Section 10.3.2. For the avoidance of doubt, WPCo, in its capacity as an Owner of the Facility, shall bear its proportionate share of Environmental Liabilities under this Section 10.3.2 in respect of its Ownership Interest.

10.3.2 Operator Indemnity for Environmental Liabilities. Subject to the provisions of Section 10.1 and the limitations of liability in Section 11.1, Operator shall indemnify and hold harmless the Non-Operator Owner Indemnitees from and against, and no Non-Operator Owner Indemnitee shall be responsible hereunder for any Liabilities, including any civil and criminal fines or penalties and other costs and expenses incurred, assessed, sustained or suffered by or against any Person as a result of or in connection with any breach or violation of or any other matters governed by Environmental Laws to the extent caused by the gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law or willful breach of this Agreement by Operator or arising out of the existence, generation, use, emission, collection, treatment, storage, transportation, disposal, recovery, removal, release, discharge or dispersal of Hazardous Materials brought on Site by Operator or its Affiliates or agents on or after the Effective Date (the "Operator Environmental Liabilities"). Operator understands and agrees that any Operator Environmental Liabilities paid by Operator pursuant to this Section 10.3.2 shall not be Operating Costs hereunder.

10.3.3 Governmental Actions. During the Term, Operator shall use commercially reasonable efforts to cooperate with and assist the Owners with their acquisition of data and information, and preparation and filing with appropriate Governmental Authorities of any notices, plans, submissions, or other materials and information necessary for compliance by the Owners with applicable Environmental Laws and the requirements of any Permits related to the Facility. All such environmental reports shall be submitted by, and in the names of, both Owners. All reasonable and documented costs associated therewith, including the reasonable costs of any outside consultants, legal services, Governmental Authority charges, sampling and remedial work shall be paid by the Owners as an Operating Cost, and the Non-Operator Owner shall reimburse WPCo to the extent of the Non-Operator Owner's pro rata share, unless such costs are incurred arising out of or associated with Operator Environmental Liabilities that are subject to Operator's indemnity obligation pursuant to Section 10.3.2 hereof. Nothing contained herein shall be construed as requiring Operator to take any corrective action with respect to Environmental Liabilities unless (x) affirmatively and expressly directed in writing to so do by the Operating Committee and appropriate funding is made available, or (y) affirmatively and expressly directed to do so by a Governmental Authority, in order to comply with any Environmental Law, in which case the cost of any corrective actions so undertaken shall be deemed an Environmental Liability subject to Section 10.3.1 hereof (if not otherwise reimbursed as an Operating Cost hereunder), unless such Environmental Liability arises out of or is associated with Operator Environmental Liabilities subject to Operator's indemnity obligation pursuant to Section 10.3.2 hereof.

## ARTICLE XI - LIABILITIES OF THE PARTIES

11.1 Limitations of Liability. Notwithstanding any provision in this Agreement that may be susceptible to contrary interpretation, neither the Parties nor any Non-Operator Owner Indemnitees or Operator Indemnitees shall be liable for consequential or indirect loss or damage, including loss of profit, cost of capital, loss of goodwill, increased Operating Costs, or any special or incidental damages; provided, however, that notwithstanding the foregoing, in no event will the foregoing limitations of liability be applied to limit the extent of the liability of either Party to the other for or with respect to any Claims of third parties or to the extent arising from gross negligence, actual fraud, willful violation of Applicable Law or willful breach of this Agreement. The Parties further agree that the waivers and disclaimers of liability, indemnities, releases from liability and limitations of liability expressed in this Agreement shall survive termination or expiration of this Agreement, and shall apply in all circumstances, whether in contract, equity, tort or otherwise, regardless of the fault, negligence (in whole or in part), strict liability, breach of contract or breach of warranty of the Party indemnified, released or whose liabilities are limited, and shall extend to the Non-Operator Owner Indemnitees and Operator Indemnitees.

11.2 Operator's Total Aggregate Liability. Except to the extent that a Non-Operator Owner Indemnitee suffers Liabilities that are caused by, result from or arise out of Operator's or its Affiliates' breach of Article XIII or its gross negligence, actual fraud, willful violation of Applicable Law or willful breach of this Agreement, or willful misconduct (including in connection with any Services), the total liability of Operator to the Non-Operating Owner for all Liabilities arising out of, connected with or resulting from any events occurring or claims made in connection with this Agreement, whether based in contract, warranty, tort, strict liability or otherwise, shall not exceed, in the aggregate, the sum of (i) an amount equal to twenty-five percent (25%) of the Operating Costs, but excluding Operating Costs relating to any services, goods, inventory and equipment provided hereunder by third parties other than Operator's Affiliates, incurred pursuant to this Agreement in the prior twelve (12) month period, *plus* (ii) the Non-Operating Owner's fifty percent (50%) share of any insurance proceeds actually received by the Operator or paid on the Operator's behalf with respect to the relevant loss or damages under the insurance policies procured by the Operator pursuant to Section 9.1.

11.3 No Warranties or Guarantees.

11.3.1 EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, NEITHER PARTY MAKES ANY WARRANTIES OR GUARANTEES TO THE OTHER, EITHER EXPRESS OR IMPLIED, WITH RESPECT TO THE SUBJECT MATTER OF THIS AGREEMENT, AND BOTH PARTIES DISCLAIM AND WAIVE ANY IMPLIED WARRANTIES OR WARRANTIES IMPOSED BY LAW, INCLUDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR ANY IMPLIED WARRANTY OF NON-INFRINGEMENT.

11.3.2 OPERATOR IS ACTING AS AGENT OR OTHERWISE AS A RESELLER WITH RESPECT TO ALL SERVICES, GOODS, INVENTORY AND EQUIPMENT PROVIDED HEREUNDER BY THIRD PARTIES OTHER THAN OPERATOR'S AFFILIATES, AND, AS SUCH, DOES NOT PROVIDE ANY WARRANTY FOR SUCH THIRD PARTY SERVICES, GOODS, INVENTORY OR EQUIPMENT PROVIDED HEREUNDER. ALL SUCH THIRD PARTY SERVICES, GOODS, INVENTORY AND EQUIPMENT ARE PROVIDED AS IS, WHERE IS, WITH ALL FAULTS AND WITHOUT WARRANTY OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OR ANY IMPLIED WARRANTY OF NON-INFRINGEMENT UNLESS CAUSED BY THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT, ACTUAL FRAUD, WILLFUL VIOLATION OF ANY APPLICABLE LAW OR WILLFUL BREACH OF THIS AGREEMENT BY OPERATOR OR ITS AFFILIATES. THE SOLE REMEDY IN CONNECTION WITH ANY DEFECTS IN OR FAILURES OF SUCH THIRD PARTY SERVICES, GOODS, INVENTORY OR EQUIPMENT (WHETHER A CLAIM FOR SUCH DEFECT ARISES UNDER CONTRACT, TORT, STRICT LIABILITY, STATUTE, OR ANY OTHER LEGAL OR EQUITABLE THEORY OR PRINCIPLE INCLUDING NEGLIGENCE) SHALL BE TO SEEK RECOURSE EXCLUSIVELY FROM THE COUNTERPARTIES TO THE THIRD PARTY CONTRACTS, UNLESS THE DEFECT OR FAILURE WAS CAUSED BY THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT, ACTUAL FRAUD, WILLFUL VIOLATION OF ANY APPLICABLE LAW OR WILLFUL BREACH OF THIS AGREEMENT BY OPERATOR OR ITS AFFILIATES.

## ARTICLE XII - CONFIDENTIALITY

12.1 General. During the Term, and for the later of three (3) Years after the termination of this Agreement or five (5) Years after receipt of the applicable Confidential Information, each Party shall hold in confidence any Confidential Information supplied by or on behalf of the other Party. Each receiving Party further agrees to require its contractors, vendors, suppliers and employees, agents or prospective purchasers to preserve the confidentiality of Confidential Information. The receiving Party may make necessary disclosures to third parties directly engaged in the operation, ownership or financing of the Facility if such third parties are under an obligation to receive and hold such Confidential Information in confidence.

12.2 Exceptions. The provisions of this Article XII do not apply to information within one or more of the following categories:

12.2.1 Public Domain. Information that was in the public domain prior to the receiving Party's receipt or that subsequently becomes part of the public domain by publication or otherwise, except by the receiving Party's or its Affiliate's wrongful act.

12.2.2 Prior Receipt. Information that the receiving Party can demonstrate was in its possession prior to receipt thereof from the disclosing Party so long as such possession did not result from a violation of a confidentiality obligation.

12.2.3 Third Party Delivery. Information received from a third party having no obligation of secrecy with respect thereto.

12.2.4 Permitted Disclosures. Information disclosed by an Owner to Lenders or prospective Lenders, equity investors or prospective equity investors, prospective purchasers, consultants, attorneys, accountants and other designated agents in each case on a confidential, need-to-know-basis.

12.2.5 Regulatory Filings. Information required to be disclosed by an Owner in connection with any required regulatory or administrative filings.

12.3 Required Disclosure. Notwithstanding the forgoing, any receiving Party required by law, rule, regulation, subpoena or order, or in the course of regulatory, administrative or judicial proceedings, to disclose Confidential Information that is otherwise required to be maintained in confidence pursuant to this Article XII, may make disclosure notwithstanding the provisions of this Article XII. Prior to doing so, the receiving Party, promptly upon learning of the requirement, shall notify the disclosing Party of the requirement and cooperate to the maximum extent practicable to minimize the disclosure of Confidential Information. Any receiving Party disclosing Confidential Information pursuant to this Section 12.3 shall use commercially reasonable efforts, at the disclosing Party's cost, to obtain proprietary or confidential treatment of Confidential Information by the third party to whom the information will be disclosed, and to the extent such remedies are available, shall use commercially reasonable efforts to seek protective orders limiting the dissemination and use of Confidential Information. Nothing in this Agreement is intended to prevent the disclosing Party from appearing in any proceedings and objecting to the disclosure.

## ARTICLE XIII - TITLE, DOCUMENTS AND DATA

13.1 Materials and Equipment. Operator shall use commercially reasonable efforts to cause title to all materials, equipment, supplies, consumables, spare parts and other items purchased or obtained by Operator on an Operating Cost basis ("Facility Equipment") to pass directly from the vendor or supplier to, and vest in, each Owner to the extent of such Owner's Ownership Interest. Operator shall have no title or other claim to such items other than in its capacity as an Owner of the Facility.

13.2 Documents. All Manuals, operational data, Facility drawings, Operator reports and records and other materials and documents (both paper and electronic) created by Operator, its Affiliates or their respective employees, representatives or contractors in connection with performance of the Services are the property of each Owner to the extent of its Ownership Interest in the Facility. All such materials and documents shall be available for review by the Non-Operator Owner at all reasonable times during development and promptly upon completion. All such materials and documents required to be submitted for the approval of the Operating Committee shall be prepared and processed in accordance with the requirements and specifications set forth herein. However, the Operating Committee's approval of materials and documents submitted by Operator shall not relieve Operator of its responsibility to perform it obligations under this Agreement.

13.3 Proprietary Information. Where materials or documents prepared or developed by Operator or its Affiliates, or their respective employees, representatives or contractors, contain proprietary or technical information, systems, techniques or know-how previously developed by them or acquired by them from third parties (the "Operator Proprietary Information"), the Non-Operator Owner shall have an irrevocable license to use such Operator Proprietary Information to the extent necessary for the operation or maintenance of the Facility at no additional cost to the Non-Operator Owner.

## ARTICLE XIV - MISCELLANEOUS PROVISIONS

14.1 Assignment. This Agreement shall not be assignable, in whole or in part, by a Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed, except that this Agreement may be (i) collaterally assigned by an Owner without such consent to a Lender in connection with such Lender's financing of such Owner's Ownership Interest and (ii) assigned by an Owner (in whole but not in part) without such consent to the transferee of its Ownership Interest, whether by merger, division, sale of equity interest, or otherwise, in each case, solely to the extent that such transfer of its Ownership Interest is in accordance with the Ownership Agreement. Any assignment pursuant to this Section 14.1 shall not relieve the assigning Party of any of its obligations under this Agreement that arose prior to the date of such assignment. This Agreement shall be binding upon and inure to the benefit of the successors and permitted assigns of the Parties.

14.2 Effect of Bankruptcy. The Parties intend that, in the event of a Bankruptcy, payments required under this Agreement shall be deemed to be administrative expenses as defined in 11 U.S.C. §503.

14.3 Access. The Non-Operator Owner and Lenders and their agents and representatives shall have access to the Facility, all Facility operations and any documents, materials and records and accounts relating to the Facility operations for purposes of inspection and review. Upon the request of the Non-Operator Owner and its agents and representatives, Operator shall provide such Persons with access to all data and logs Operator maintains regarding the Facility. During any inspection or review of the Facility, the Non-Operator Owner and Lenders and their agents and representatives shall comply with all of Operator's safety and security procedures, and shall conduct inspections and reviews in such a manner as to cause minimum interference with Operator's activities. Operator also shall cooperate with the Non-Operator Owner in allowing its agents and representatives access to the Facility.

14.4 Subcontractors; Subagents.

14.4.1 Operator shall have the right to hire third-party subcontractors or to acquire rights from third parties to provide all or part of any Services hereunder without the prior consent of the Operating Committee. The cost of such third-party Services or acquisition of such rights shall be Operating Costs in accordance with Section 7.2.1. Operator, for the benefit of the Owners, shall use commercially reasonable efforts to obtain from all subcontractors and suppliers, including any subcontractors and suppliers who are Affiliates of Operator, customary guarantees and warranties to the extent available with respect to the equipment, goods, services or other work provided or performed by such subcontractor and supplier. Notwithstanding the foregoing or anything to the contrary, Operator shall not, without the prior written approval of Non-Operator Owner, such approval not to be unreasonably withheld, conditioned or delayed, procure or enter into any agreement with any third-party subcontractor with respect to the Services with a cost included in the Operating Costs in excess of $500,000 in any Year. Each agreement with a third-party subcontractor shall reflect costs that are on an arm's-length basis and no greater in any material respect than Operator could reasonably provide on Operator's own (or through its Affiliates) without material hardship.

14.4.2 Operator may delegate any obligations hereunder to one or more Affiliates, or designate one or more Affiliates as subagents for the performance of its obligations, and, to the extent such Affiliate performs or acts as subagent with respect to any obligation of Operator hereunder, such Affiliate shall enjoy the rights and benefits of Operator pursuant to this Agreement (including, for the avoidance of doubt, Article X and Article XI hereof). Notwithstanding the foregoing, Operator shall not, without the prior written approval of Non-Operator Owner, such approval not to be unreasonably withheld, conditioned, or delayed, procure or enter into any agreement with any of its Affiliates (other than for Facility Personnel to perform the Services) (i) with a committed value in excess of $500,000 or (ii) that may not be cancelled by or at the request of Non-Operator Owner upon no more than ninety (90) days' notice without penalty. Each agreement with an Affiliate of Operator, other than for Facility Personnel to perform the Services, shall reflect costs that are no greater in any material respect than Operator could obtain on an arm's-length basis with a bona fide third party at such time. Notwithstanding anything to the contrary in this Agreement, Operator shall be permitted to delegate any of its rights, duties and obligations under this Agreement and the Ownership Agreement to AEPSC without the consent of Non-Operator Owner, subject to Section 14.4.3.

14.4.3 If one or more Affiliates perform Services as subagents or subcontractors hereunder, Service Provider shall remain liable for such Affiliate's obligations hereunder and for any breach by such Affiliate of the terms of this Agreement (to the same extent as if such breach was committed by Service Provider).

14.5 Not for Benefit of Third Parties. Except where a contrary intention is expressly stated, this Agreement and each provision hereof are for the exclusive benefit of the Parties that executed this Agreement and not for the benefit of any third party.

14.6 Force Majeure.

14.6.1 Events Constituting Force Majeure. A "Force Majeure Event" is any event that (i) restricts or prevents performance under this Agreement, (ii) is not within the reasonable control of the Party affected or caused by the fault or negligence of the affected Party and (iii) cannot be overcome or avoided by the exercise of due care. Force Majeure Events include the following, so long as in each case the requirements of the foregoing clauses (i), (ii) and (iii) are satisfied, failure of a Party to perform due to drought, flood, earthquake, storm, fire, lightning, tornado or other unusually severe storm or environmental conditions, epidemic, war (whether declared or undeclared), terrorism (whether domestic or foreign, state-sponsored or otherwise), revolution, insurrection, riot, civil disturbances, protests, sabotage (but not including any sabotage involving personnel of Operator), work stoppages (i.e., strikes) (but not including any work stoppages or strikes involving any personnel of Operator, whether on-site or off-site), accident or curtailment of supply, unavailability of construction materials or replacement equipment beyond the affected Party's control, inability to obtain and maintain Permits from any Governmental Authority for the Facility, other acts or omissions of any Governmental Authority, including any form of compulsory government acquisition or condemnation of all or part of the Facility (including a "taking"), restraint by court order, changes in Applicable Law that affect performance under this Agreement, other acts of Governmental Authorities including in response to any of the foregoing. Except for the obligation of each Party to make payments of amounts owed to the other Party, each Party is excused from performance and will not be considered to be in default in respect to any obligation if and to the extent that performance of such obligation is prevented by a Force Majeure Event. Neither Party shall be relieved of its obligations under this Agreement solely because of increased costs or other adverse economic consequences that may be incurred through the performance of such obligations.

14.6.2 Notice. If a Party's ability to perform its obligations under this Agreement is affected by a Force Majeure Event, the Party claiming such inability shall (i) promptly notify the other Party of the Force Majeure Event, its cause, its anticipated duration and any action being taken to avoid or minimize its effect and confirm the same in writing within three (3) Business Days of its discovery, (ii) promptly supply such available information about the Force Majeure Event and its cause as reasonably may be requested by the other Party and (iii) work diligently to remove the cause of the Force Majeure Event or to lessen its effect.

14.6.3 Scope. The suspension of performance arising from a Force Majeure Event shall be of no greater scope and no longer duration than necessary. The excused Party shall use its reasonable best efforts to remedy its inability to perform.

14.7 Dispute Resolution. Any and all disputes shall be resolved pursuant to the dispute resolution procedures set forth in the Ownership Agreement.

14.8 Amendments. No amendments or modifications of this Agreement are valid unless in writing and signed by duly authorized representatives of the Parties.

14.9 Survival. Notwithstanding any provisions to the contrary, the obligations set forth in Article VII and Article VIII, Article X, Article XI and Article XII, Article XIV the limitations on liabilities set forth in Article XI will survive, in full force, the expiration or termination of this Agreement.

14.10 No Waiver. No delay, waiver or omission by the Non-Operator Owner or Operator to exercise any right or power arising from any breach or default by the Non-Operator Owner or Operator with respect to any of the terms, provisions or covenants of this Agreement shall be construed to be a waiver by the Non-Operator Owner or Operator of any subsequent breach or default of the same or other terms, provisions or covenants on the part of the Non-Operator Owner or Operator.

14.11 Notices. Any written notice required or permitted under this Agreement shall be deemed to have been duly given on the date of receipt, and shall be either delivered personally to the Party to whom notice is given, or mailed to the Party to whom notice is to be given, by facsimile, courier service or first-class registered or certified mail, return receipt requested, postage prepaid, and addressed to the addressee at the address indicated below, or at the most recent address specified by written notice given in the manner provided in this Section 14.11:

If to Operator:

[_________________]
[_________________]
[_________________]

If to the Non-Operator Owner:

[_________________]
[_________________]
[_________________]

14.12 Representations and Warranties. Each Party represents and warrants to the other Party that, as of the date hereof:

14.12.1 Existence. It is duly organized and validly existing under the laws of the state of its organization and has all requisite power and authority to own its property and assets and conduct its business as presently conducted or proposed to be conducted under this Agreement.

14.12.2 Authority. It has the power and authority to execute and deliver this Agreement, to consummate the transactions contemplated hereby and to perform its obligations hereunder.

14.12.3 Validity. It has taken all necessary action to authorize its execution, delivery and performance of this Agreement, and this Agreement constitutes the valid, legal and binding obligation of such Party enforceable against it in accordance with its terms, except as such enforcement may be limited by Bankruptcy, insolvency, moratorium or similar laws affecting the rights of creditors or by general equitable principles (whether considered in a proceeding in equity or at law).

14.12.4 No Conflict. Neither the execution or delivery of this Agreement, the performance by such Party of its obligations in connection with the transactions contemplated hereby, nor the fulfillment of the terms and conditions hereof, conflicts with or violates any provision of its constituting documents.

14.12.5 No Consent. No consent or approval (including any Permit that such warranting Party is required to obtain) is required from any third party (including any Governmental Authority) for either the valid execution and delivery of this Agreement, or the performance by such Party of its obligations under this Agreement, except such as have been duly obtained or will be obtained in the ordinary course of business.

14.12.6 No Breach. None of the execution or delivery of this Agreement, the performance by such Party of its obligations in connection with the transactions contemplated hereby, or the fulfillment of the terms and conditions hereof either conflicts with, violates or results in a breach in any material respect of, any Applicable Law currently in effect, or conflicts with, violates or results in a breach of, or constitutes a default under or results in the imposition or creation of, any lien or Encumbrance under any material agreement or instrument to which it is a party or by which it or any of its properties or assets are bound.

14.12.7 No Material Claims. It is not a party to any legal, administrative, arbitral or other proceeding, investigation or controversy pending or threatened that would adversely affect such Party's ability to perform its obligations under this Agreement.

14.13 Additional Representation and Warranty by Operator. Operator further represents and warrants to the Non-Operator Owner that it has, or has obtained through the retention of a qualified operations and maintenance service provider, substantial expertise and experience in the operation and maintenance of comparable power generation facilities and it, or its applicable subcontractor, is fully qualified to provide such services at the Facility in accordance with the terms of this Agreement.

14.14 Counterparts. The Parties may execute this Agreement in counterparts that, when signed by each of the Parties, constitute one and the same instrument. Thereafter, each counterpart shall be deemed an original instrument as against any Party who has signed it. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission shall be effective as delivery of a manually executed counterpart of this Agreement.

14.15 Governing Law; Venue; Waiver of Jury Trial. The interpretation and performance of this Agreement is governed by and shall be construed in accordance with the laws of the State of New York, exclusive of the conflicts of law provisions thereof that would require the application of the laws of a different jurisdiction. Each Party hereby agrees that any Action arising out of or relating to this Agreement brought by a Party(or any of their respective successors or assigns) shall be brought and determined in any state or federal court sitting in the State of New York, within the Borough of Manhattan, City of New York, and the Parties hereby irrevocably submit to the exclusive jurisdiction of the aforesaid courts for themselves and with respect to their property, generally and unconditionally, with regard to any such Action arising out of or relating to this Agreement and the transactions contemplated hereby, and the appellate courts from any thereof in connection with any action arising out of or relating to this Agreement or any other agreement related to the Facility or any Facility asset and the transactions contemplated hereby, and consents that any such action may be brought in such courts and waives any objection it may now or hereafter have to the venue of any such action in any such court or that such action was brought in an inconvenient court. EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ALL RIGHTS TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING TO THIS AGREEMENT.

14.16 Interpretation. Titles or captions contained in this Agreement are inserted only as a matter of convenience and for reference, and in no way define, limit, extend, describe or otherwise affect the scope or meaning of this Agreement or the intent of any provision hereof. All exhibits and appendices attached hereto are considered a part hereof as though fully set forth herein. This Agreement was jointly drafted and negotiated by the Parties. In the event of a dispute, this Agreement shall not be construed against either Party based upon its drafting.

14.17 Severability. If any provision of this Agreement, or the application of any such provision to any Person or circumstance, is held invalid by any court or other forum of competent jurisdiction, the remainder of this Agreement, or the application of such provision to Persons or circumstances other than those as to which it is held invalid, shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in a manner materially adverse to a Party. Upon any such determination of invalidity, the Parties shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties as closely as possible in an acceptable manner in order that this Agreement is consummated as originally contemplated to the greatest extent possible.

14.18 Cooperation in Financing. Operator shall execute and deliver any customary and reasonable agreement and consent to assignment, together with an opinion of counsel at Non-Operator Owner's expense, as may be reasonably requested by Non-Operator Owner in connection with any financing of the Facility. Operator shall promptly respond to reasonable requests, including requests for management presentations, by Non-Operator Owner and any of its Lenders or their representatives, in each case at Non-Operator Owner’s sole cost and expense, for information regarding the Operator and its performance of its duties hereunder and the operation, maintenance and administration of the Facility. Operator agrees to use commercially reasonable efforts to cooperate with any of Non-Operator Owner’s Lenders and their representatives and to provide such Lenders and representatives with reasonable access to and tours of the Facility (including review of documents, materials, records and accounts), in each case at Non-Operator Owner’s sole cost and expense.

[*Signature page follows.*]

IN WITNESS WHEREOF, the Parties have executed this Agreement through their duly authorized officers as of the date set forth in the preamble to this Agreement.

**KENTUCKY POWER COMPANY**

By: ______________________________
Name:
Title:

**WHEELING POWER COMPANY**

By: ____________________________________
Name:
Title:

## APPENDIX A – SCOPE OF SERVICES

| Task Name | Description |
|---|---|
| **Routine Services** | Provide operational services as reasonably necessary for electrical power generation. |
| **Detailed Programs** | Implement Operator human resources program. Implement Operator-drafted, Owner-approved programs in safety, administration, maintenance, and training. Implement Facility's existing programs in operating, maintenance, chemistry, NERC and environmental compliance (or, at the Operating Committee's request, develop or enhance such programs at actual cost and implement). Ensure compliance with NERC requirements, Environmental Law, Applicable Law, and all Permits. |
| **Routine Maintenance** | Perform routine and preventive maintenance actions on all Facility systems and equipment in accordance with vendor instructions and the maintenance plan for the Facility. This program includes:<br><br>**Service Checks** – Conduct visual equipment inspections and log significant parameters such as pressures, temperatures, and flow rates. Trend and analyze this information as appropriate.<br><br>**Routine and Fixed Interval Maintenance** –Identify preventive maintenance requirements. Schedule and assign routine maintenance during Facility operation, planned outages, and forced or unscheduled outages. |
| **Predictive Maintenance Program** | As appropriate, conduct/oversee predictive maintenance within the cost-effective capability of the Facility Personnel. For those maintenance requirements that are not cost-effective for the Facility Personnel, oversee predictive maintenance services provided by vendors. |
| **Major Maintenance and Repairs** | In coordination with and support of the Facility Agreements and generation plan, arrange for scheduled inspections and overhauls on major equipment. Retain vendors for the benefit of the Owners for unscheduled major repairs as required and manage and oversee repairs and modifications. |
| **Capital Improvements** | Conduct/oversee all capital improvements. As appropriate, retain vendors for the benefit of the Owners to design, construct and implement capital improvements. |
| **Facility Outages** | Use commercially reasonable efforts to manage all Facility outages (planned, unscheduled, forced) to optimize outage duration and impact on production: |

| Task Name | Description |
|---|---|
| | **Task Assignment** – Identify and schedule all maintenance that requires a Facility outage or equipment to be taken out of service.<br><br>**Work Schedule –** Develop and implement a schedule to track material outage preparations, work and testing, including corrective maintenance actions, contractor work and scheduled preventive maintenance. Conduct preparations to support this plan, including ordering and receiving required spare parts. |
| **Assistance to the Non-Operator Owner and Operating Committee** | Provide assistance to the Non-Operator Owner and the Operating Committee, as reasonably requested with the execution of the Non-Operator Owner's and the Operating committee's duties relative to operation of the Facility. |
| **Facility Administration** | Conduct administration to meet Operator requirements and Owners' goals, including:<br><br>**Budgets** – Prepare annual Budgets and submit them for Operating Committee approval in accordance with the Ownership Agreement and this Agreement. Following approval, manage operations and expenditures to comply with each Budget. Generate budget variance reports, as required.<br><br>**Procurement** – Establish and implement a purchasing system. Procure, for the benefit of the Owners, including negotiations and contracting, for all materials, equipment, chemicals, supplies, services, parts, and other miscellaneous items required for the provision of the Services. Pay all invoices in a timely manner. Provide credit support as required by third parties for the operation of the Facility, including contract counterparties and Governmental Authorities. Minimize Owner costs as much as feasible.<br><br>**Inventory Control** – Implement a cost-effective inventory control system designed to ensure that spare parts, materials, and supplies are properly stored and accounted for and that adequate supplies are available at all times to support the provision of the Services.<br><br>**Personnel Matters** – In compliance with Operator programs and policies, manage all payroll and employee relations, labor relations, and independent contractor issues, as required. These tasks include: employment; compensation and benefits; initial training; and employee and independent contractor relations. Provide reasonable support to recruit, hire, transfer, or otherwise acquire and retain qualified Facility Personnel to maintain the staffing levels and skill mix required for successful long-term provision of the Services. |

| Task Name | Description |
|---|---|
| | **Community Relations** – In coordination with and with the approval of the Operating Committee, conduct a community relations program to establish the Facility and its employees as "good citizens" in the local community.<br>**Regulatory –** Perform all duties set forth in Section 7.8 of the Ownership Agreement with respect to Emission Allowances (as defined therein). |
| **Work Assignment** | Assign work to either Facility Personnel or vendors as cost-effective and appropriate based on overall guidance from the Operating Committee. Normally, Facility Personnel conduct preventive maintenance and actions requiring a high degree of Facility knowledge and vendors perform tasks needing equipment or expertise that are not cost-effective to maintain at the Facility. Vendors also perform tasks that make sense to minimize outage time and costs. |
| **Buildings and Grounds** | Arrange for janitorial, garbage pickup and landscape services and maintain all access roads, office buildings, and other structures in reasonable repair. |
| **Reports** | Prepare and submit operation and maintenance service reports as requested relative to performance, including environmental compliance records, maintenance and repair status, Facility operating data, and any other information reasonably requested by the Operating Committee or the Non-Operator Owner. |
| **Security** | Implement or arrange for implementation of security measures in accordance with the Operating Committee-approved Facility security plan. |
| **Safety** | Continue to implement Corporate and Plant Level Safety Programs including on-site visits and discussions at the facility. |
| **PJM Capacity Analysis** | Analysis and plant level information to PJM as part of PJM's FRR or RPM Capacity Market requirements |
| **Information Systems** | Manage the Facility's information technology infrastructure, including phone systems, internet connectivity, hardware and software. Implement or arrange for implementation of cybersecurity policies and procedures in compliance with NERC requirements and Applicable Law, in accordance with the Operating Committee-approved Facility cybersecurity plan. |
| **Training Program** | Implement a continuing program of training designed to orient new Facility Personnel, refresh/cross-train existing Facility Personnel, qualify/re-qualify Facility Personnel, and keep all Facility Personnel |

| Task Name | Description |
|---|---|
| | aware of Operating Committee -approved Facility safety requirements and emergency procedures. This program includes specialty skills training. |
| **Drawing/Manual Maintenance** | Maintain the Facility library and update the Manuals and vendor service manuals. Update (or arrange for updating) Facility drawings to reflect changes to the as-built configuration. In addition to document management, maintain physical Facility configuration control. |

| Task Name | Description |
|---|---|
| **Fuel Purchasing and Handling** | • Procure coal, reagents, fuel oil supply or transportation service agreements as needed to operate the Facility and establish and maintain reserves of coal in common stock piles of such quality and in such quantities as the Operating Committee shall determine<br>• Contract administration for Fuel supply contracts along with legal review.<br>• Third Party Settlements of fuel related supply and inventory tracking in ComTrac system<br>• Joint Books Accounting to prepare information for billing among co-owners per agreement<br>• Analysis of fuel related costs for data requests from regulatory bodies or joint owner<br>• Provide fuel reserves against interruptions of normal fuel supply and as is necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from such coal stock piles by the Facility during each month.<br>• Receive coal and provide fuel handling<br>• Fuel coordinator functions to review fuel quality with third party suppliers at coal or limestone facilities.<br>• Administer and reconcile volumes of all fuel with suppliers<br>• Administer and comply with the requirements set forth in the Facility's fuel agreements, including quality testing and invoice review and approval<br>• Administer and comply with the requirements set forth in the Facility's coal ash, gypsum and combustion byproduct disposal and sales agreements, including invoice review and approval |

| Task Name | Description |
|---|---|
| **Day Ahead and Real Time Market Operations** | • Unit Generation Dispatch – Monitor signals and take direction from PJM for generating units. Relay these directions, commitments and settings to the Unit Operators and Controls. Relay information on real time unit conditions to Transmission Owner (TO) and PJM.<br>• GADS Reporting – Create GADS events as they are scheduled or occur. Submit monthly event reporting as required by NERC and PJM.<br>• Outage Support and Communications to PJM – Relay outage/curtailment information from plant personnel to PJM. Schedule maintenance and planned outages/curtailments, and maintain updates as they arise.<br>• Unit Characteristic Updates to PJM – Provide any relevant configuration updates related to generating units to PJM that may occur.<br>• Telemetry – Maintain current real time telemetry to/from the plant, PJM and Market Operations control center. |
| **Administration of Contracts** | • Administer, perform and enforce all contractual obligations and arrangements, including all warranties applicable thereto, entered into by Operator for the benefit of the Owners with respect to the Facility<br>• Act as agent on behalf of the Non-Operating Owner with respect to the administration, performance and enforcement of any contracts or purchase orders (including fuel supply or transportation contracts) with respect to the Facility that are in the name of the Non-Operator Owner as a result of the Non-Operator Owner having served as the Operator prior to the Effective Date |
| **Insurance** | • Procure on behalf of each Owner such property and other insurance policies as required by the insurance program established by the Operating Committee in accordance with the Ownership Agreement. |

| Task Name | Description |
|---|---|
| **Decommissioning** | • Manage and contract with vendors and other parties to perform Decommissioning Work. This includes the management of required regulatory filings, permitting, engineering assessments, and the contracting for demolition and or liability transfers. Upon mutual agreement between Operator and the Operating Committee, Operator may conduct all or a portion of the Facility and/or Site Decommissioning from its and its Affiliates resources. |

## APPENDIX B – INITIAL BUDGET AND PLAN

[To be attached as of the Effective Date]

## APPENDIX C – OPERATING COSTS WORKSHEET/SAMPLE INVOICE

[See attached.]

**PAGE 1**

INVOICE # **xxx-xxxxxxxx**

**Month of Billing**

**PAYMENT DUE BY:** **Date Due**

Kentucky Power Company
Attn: xxxx
Address
City, State Zip Code

Dear xxxx:

**This is the billing report for Actual charges for the month of Month of billing for the Mitchell Generating Plant. Please include the invoice number above on your wire transfer to the receiving bank listed on that report. If you have any questions please call: xxxx at xxx-xxx-xxx or E-mail to xxx@aep.com**

| **Operating & Maintenance Agreement as Operator Article VII, Section 2:** | **Amount** |
|---|---|
| i. KPCO'S Actual cost of coal inventory receipts of Mitchell Power Plant. | $3,914,522.89 |
| ii. KPCO'S Actual cost of coal handling inventory receipts of Mitchell Power Plant. | $249,855.00 |
| iii. KPCO'S Actual cost of fuel oil inventory receipts of Mitchell Power Plant. | $12,185.50 |
| iv. KPCO'S Actual cost of Limestone inventory receipts of Mitchell Power Plant. | $55,080.45 |
| v. KPCO'S Actual cost of Urea inventory receipts of Mitchell Power Plant. | $19,351.35 |
| vi. KPCO's share of total cost of operation of Mitchell Power Plant. | $227,744.80 |
| vii. KPCO's share of total cost of maintenance of Mitchell Power Plant. | $295,700.00 |
| viii. KPCO's share of total cost of fuel handling/fly ash of Mitchell Power Plant. | $50,000.00 |
| ix. KPCO's share of A&G expenses. | $145,000.00 |
| x. KPCO's share of Other Operating Costs. | $0.00 |
| ***Total Operating Expenses*** | $4,969,439.98 |
| KPCo's share of Capital Expenditures | $100,000.00 |
| Storeroom Inventory Activity | $150,000.00 |
| ***TOTAL AMOUNT DUE WHEELING POWER COMPANY*** | **$5,219,439.98** |

| ***Wiring Instructions*** | | |
|---|---|---|
| | Name on Acct: | Wheeling Power Co |
| | Bank: | Bank |
| | Acct: | Acct |
| | ABA: | ABA |
| | Ref: | Invoice #, xxx-xxxxxxxx |

[RATE SCHEDULE NO. 303]

# MITCHELL PLANT OWNERSHIP AGREEMENT

KENTUCKY POWER COMPANY

and

WHEELING POWER COMPANY

THIS MITCHELL PLANT OWNERSHIP AGREEMENT (this "Agreement"), with an effective date of [_______] (the "Effective Date"), is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo"); Wheeling Power Company, a West Virginia corporation ("WPCo") (such parties hereinafter sometimes referred to as an "Owner" and together the "Owners"); and, solely with respect to Section 13.4, American Electric Power Service Corporation, a New York corporation ("AEPSC").

WITNESSETH:

WHEREAS, KPCo and WPCo, as of the date hereof, each own a fifty percent (50%) undivided ownership interest in the Mitchell Power Generation Facility (each such percentage interest, an Owner's "Ownership Interest"), which consists of two coal-fired generating units (each, a "Unit"), with each Unit having a nominal nameplate capacity of 800 MW, located in Moundsville, West Virginia (as further defined herein, the "Mitchell Plant");

WHEREAS, KPCo, WPCo and AEPSC are parties to that certain Mitchell Plant Operating Agreement, dated as of December 31, 2014 (the "Original Operating Agreement");

WHEREAS, the Original Operating Agreement sets forth certain rights and obligations of the Owners and AEPSC with respect to the Mitchell Plant and the Owners' ownership thereof;

WHEREAS, pursuant to the Original Operating Agreement, KPCo is responsible for the day-to-day operations and maintenance of the Mitchell Plant;

WHEREAS, the Owners and AEPSC desire to replace the Original Operating Agreement to set forth the rights and obligations of the Owners with respect to the Mitchell Plant and their ownership thereof and to remove AEPSC as a party thereto;

WHEREAS, in connection with the execution of this Agreement, the Owners desire to execute a separate operations and management agreement to provide for the day-to-day operation and maintenance responsibilities in respect of the Mitchell Plant (as may be amended from time to time the "O&M Agreement");

WHEREAS, the Owners have agreed that, subject to the terms and conditions of the O&M Agreement, on and after the Effective Date WPCo shall replace KPCo as the operator of the Mitchell Plant (the "Operator"); and

WHEREAS, on and subject to the terms and conditions of this Agreement, the Owners have committed to undertake a Buyout Transaction (as hereinafter defined), pursuant to which WPCo shall purchase KPCo's Ownership Interest on or prior to December 31, 2028, unless an Early Retirement Event (as hereinafter defined) occurs.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories hereto agree as follows:

# ARTICLE ONE
# OWNERSHIP AND OPERATIONS

1.1 To the greatest extent permitted by Applicable Law, the Mitchell Plant and all assets (tangible and intangible) and property (real and personal) owned, leased, held, developed, constructed or acquired solely for or in connection with the Mitchell Plant or the operation, maintenance or Decommissioning of the Mitchell Plant by or on behalf of an Owner or the Owners (together, the "Project Assets") shall be owned and held and deemed to be owned and held by the Owners as tenants in common in proportion to their respective Ownership Interests (except for any capital items owned in a different proportion in accordance with Section 1.8) or, in the event any Project Asset cannot be held directly by both of the Owners due to, inter alia, any pre-existing legal or contractual restrictions that cannot be altered or satisfied or where effectuating such ownership structure would result in unreasonable additional expense to the Owners, by the Operator as trustee for the Owners as tenants in common in proportion to their respective Ownership Interest. If the ownership of any Project Asset is registered or recorded in the name of one of the Owners, and notwithstanding the Owners' efforts such Project Asset cannot be held directly by both Owners as contemplated above, then such Owner in whose name ownership is registered or recorded shall hold such Project Asset in trust for itself and the other Owner in proportion to their respective Ownership Interests and, to the extent necessary or requested by the Operator or other Owner, make such Project Assets (or the benefits thereof) available for the use and benefit of the Owners (in proportion with their respective Ownership Interests), including, to the extent consistent with the foregoing, by such Owner subcontracting, sublicensing, subleasing, delegating or granting a limited power of attorney or similar appointment as agent to Operator to administer such Project Assets.

1.2 At the request of either Owner, and in accordance with Section 1.1, each Owner and the Operator shall execute all documents and do all things necessary or appropriate to register or record the Project Assets in the names of the Owners in proportion to their respective Ownership Interests (or such different proportion as any capital item may be owned in accordance with Section 1.8).

1.3 All assets (tangible and intangible) and property (real and personal) held, developed, constructed or acquired by or on behalf of the Operator for or on behalf of the Owners jointly, or any of them, shall constitute "Project Assets" subject to the ownership of both Owners as set forth in Sections 1.1 and 1.2. Except as otherwise agreed by the Owners, the Operator shall not have any right, title or interest in or to any such assets, or in or to any money paid to, collected or received by the Operator for or on behalf of either Owner, except as the agent or representative of, or for the use and benefit of, such Owners as set forth in this Agreement and in proportion to each Owner's respective Ownership Interest.

1.4 Each Owner hereby waives any rights it may have at law or equity to bring an action for partition or division of the Mitchell Plant or any Project Asset or any contracts related thereto, and agrees that it shall not (a) seek partition or division of the Mitchell Plant or any Project Asset or any contracts related thereto, or (b) take any action, whether by way of any court order or otherwise, for physical partition or judicial sale in lieu of partition of the Mitchell Plant or any Project Asset or any contracts related thereto. Nothing in this Section 1.4 shall affect the right of either Owner to dispatch its respective share of the Total Net Capability under Article Two or to Dispose of its Ownership Interest in accordance with Article Nine.

1.5 On and after the Effective Date, WPCo shall be the Operator responsible for the day-to-day operations and maintenance of the Mitchell Plant and shall operate, maintain and Decommission the Mitchell Plant for the sole benefit (and on behalf) of the Owners and in accordance with the terms and conditions of this Agreement and the O&M Agreement. KPCo agrees to take all actions reasonably necessary to facilitate WPCo's operation, maintenance and Decommissioning of the Mitchell Plant pursuant to the terms of the O&M Agreement, including providing or permitting reasonable access to the Mitchell Plant to third party contractors and other contract counterparties of each Owner or the Operator with respect to the administration, implementation and satisfaction of such contracts or agreements executed or assumed by the Operator on behalf of either Owner relating to the Mitchell Plant, including all Facility Agreements (as defined in the O&M Agreement).

1.6 The Owners shall establish and maintain such bank accounts as may from time to time be required or appropriate for paying the costs and expenses, including capital expenditures, in respect of the ownership, operation, maintenance and Decommissioning of the Mitchell Plant. The Owners shall designate only the Operator, and its representatives as reasonably requested by the Operator, as authorized signatories to such bank accounts. All withdrawals made by the Operator (or its representatives) from such bank accounts shall be made only in connection with the performance of the Operator's obligations set forth in this Agreement and the O&M Agreement.

1.7 The initial capital budget for the period from the Effective Date through December 31, 2028 (including agreed allocations of costs for capital projects between the Owners) (the "Capital Budget"), the initial annual operating budget and the initial forecast of operating and capital costs to be incurred for the period from the Effective Date through December 31, 2028 are attached hereto as Exhibit A.

1.8 Notwithstanding the provisions of this Article One, to the extent that either Owner funds or bears an amount greater than 50% of any capital expenditures or ELG Expenses as contemplated in the Capital Budget or this Agreement, the directly resulting portion of any property, plant and equipment, or improvements thereto shall be owned by the Owners in proportion to their respective amounts funded and shall be included only in such proportion in each Owner's ownership accounts for regulatory, accounting, tax and other purposes.

## ARTICLE TWO
## APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The total net capability of the Mitchell Plant at low-voltage busses of the Units, after taking into account auxiliary load demand, is 1,560,000 kilowatts (the "Total Net Capability") as of the Effective Date. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The total net generation of the Mitchell Plant during a given period, as determined by the requirements of each Owner, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for each Unit during such period (the "Total Net Generation").

2.3 Each Owner shall be entitled to receive 50% of the Total Net Capability and the Total Net Generation (with respect to each Owner, such Owner's "Assigned Capacity"), and all associated energy, capacity, ancillary services and other energy products, in accordance with this Agreement.

2.4 Except as may be determined by the Operating Committee in accordance with Section 7.6, in any hour, each Owner shall share 50% of the minimum load responsibility of each Unit.

2.5 In any hour during which any Unit is out of service, the Owners shall bear equally the cost of energy used by the out-of-service Unit's auxiliaries during such hour, which may be provided by the applicable local utility Affiliate of an Owner. Alternatively, the Owners may mutually agree in writing to each provide 50% of such energy.

## ARTICLE THREE
## REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 The Owners shall take all actions within their respective control to cause the Operator, pursuant to the O&M Agreement, from time to time to make or cause to be made any necessary or appropriate additions to, replacements of, and retirements of, capitalizable facilities associated with the Mitchell Plant in accordance with the Capital Budget and the O&M Agreement or as may otherwise be mutually agreed upon by the Owners.

3.2 In the event that, prior to execution and delivery of the Mitchell Interest Purchase Agreement, an Early Retirement Event occurs, each Owner shall (a) cause each Unit to permanently cease operations on December 31, 2028, or such other date permitted by Applicable Law as the Operating Committee may determine, (b) be responsible for, and shall timely pay, 50% of all Decommissioning Costs, (c) cooperate in good faith and take all actions reasonably necessary to facilitate the Decommissioning Work, including negotiating in good faith any contracts or agreements (including liability transfer arrangements) on behalf of either Owner or Operator, including transfers, conveyances or assignments of Facility Equipment (as defined in the O&M Agreement), as reasonably requested by either Owner or Operator to facilitate Decommissioning and (d) take, and/or instruct the Operator pursuant to the O&M Agreement to take, such actions, at the sole cost and expense of WPCo, to continue operating and maintaining the barge loading facilities and gypsum conveyor system at the Mitchell Plant and providing use of such facilities and system to the applicable contract counterparty and its representatives in accordance with, and until the expiration or earlier termination of, the CertainTeed Contract.

## ARTICLE FOUR
## WORKING CAPITAL REQUIREMENTS

4.1 The Owners shall periodically mutually determine the amount, timing and invoicing processes for funds required for use as working capital, for operating, capital and other expenses incurred in the operation, maintenance and Decommissioning (including the Decommissioning Costs) of the Mitchell Plant, and in buying equipment, materials, parts, fuel and other supplies and services necessary to operate, maintain and Decommission the Mitchell Plant and to make the timely payments of any expenses required under the O&M Agreement.

4.2 Each Owner shall, in accordance with the timing set forth in a determination made pursuant to Section 4.1, promptly provide 50% of any such amount required by the Owners pursuant to Section 4.1, except as otherwise provided for in Section 6.7.

4.3 Each Owner agrees that if such Owner fails at any time during the Term to satisfy the Ratings Requirement, it will, within thirty (30) days of such failure, provide in favor of the other Owner and maintain credit support in the form of (a) a cash deposit, (b) a guaranty issued by an Affiliate of such Owner that satisfies the Ratings Requirement in form and substance reasonably acceptable to the other Owner or (c) a letter of credit in form and substance reasonably acceptable to other Owner, issued by a commercial bank or other financial institution with a Credit Rating of at least "A-" by S&P Global Ratings, or any successor thereto ("S&P") or at least "A3" by Moody's Investors Service, Inc., or any successor thereto ("Moody's"), and in an amount equal to (i) one-half ($^1/_2$) of the then-applicable annual operating budget for the Mitchell Plant established pursuant to Section 7.2 from time to time, plus (ii) the sum of such Owner's allocated amount of capital expenditures for such year contained in the then-applicable Capital Budget, plus (iii) an amount equal to the latest estimate of Decommissioning Costs prepared by the Operator, determined on a net present value basis using a discount rate equal to the WACC as of the date of determination. Such credit support posted in favor of an Owner shall be promptly returned within thirty (30) days of the other Owner furnishing written evidence demonstrating that it satisfies the Ratings Requirement.

4.4 The Operator shall provide such credit support, including guarantees, cash deposits, letters of credit or other forms of credit support, to third parties (including contractual counterparties and Governmental Authorities) as required for the Owners' ownership, operation, maintenance and Decommissioning of the Mitchell Plant. To the extent that the Operator is required to provide such credit support to a third party in connection with any activity performed in respect of the Mitchell Plant under this Agreement (including the procurement of fuel as described in Section 5.1), the Owners shall share the reasonable and documented out-of-pocket cost of the third-party credit support incurred by the Operator (including of any credit support furnished by an Affiliate of the Operator) in accordance with their respective Ownership Interests.

## ARTICLE FIVE
## INVESTMENT IN FUEL

5.1 The Operator shall procure, establish and maintain reserves of coal in common stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply and as is necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from such coal stock piles by each Unit during each month. For purposes of this Agreement, "consumables" shall be as defined in account 502 of the Uniform System of Accounts administered by the Federal Energy Regulatory Commission ("FERC").

5.2 The quality of any coal or consumable product provided by the Operator must be reasonably acceptable to both Owners. Any coal being utilized shall be deemed to be acceptable to the Owners if it meets the following requirements: (a) coal previously utilized at the Mitchell Plant with satisfactory operating performance shall be considered acceptable for use in the Mitchell Plant, unless deemed unacceptable due to a required change of the engineering specifications making the coal no longer viable; (b) coal from any new seam or source shall be acceptable if such supply is shown to perform satisfactorily in the Mitchell Plant and is mutually acceptable to each Owner; or (c) as otherwise mutually agreed to by each Owner. Consumables from any new seam or source shall be acceptable if such supply is shown to perform satisfactorily to both Owners in the Mitchell Plant and conform to the then current engineering specifications for the Mitchell Plant or as otherwise mutually agreed by each Owner.

5.3 Each Owner shall be responsible for, and own, 50% of the investment in the common coal stock piles.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

## ARTICLE SIX
## APPORTIONMENT OF STATION COSTS

6.1 The allocation to the Owners of fuel expense associated with each Unit shall be determined by the Operating Committee as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit-cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the Mitchell Plant fuel in the stock pile and charged to the Mitchell Plant fuel consumed.

(c) In each calendar month, each Owner's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For each calendar month, the Operator will, to the extent practicable and in accordance with the O&M Agreement, determine all of the Mitchell Plant's operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.3 For each calendar month, the Operator will, to the extent practicable and in accordance with the O&M Agreement, determine all the Mitchell Plant's maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 In each calendar month, each Owner's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with this Article Six, shall be allocated as follows:

(a) Each Owner's respective share of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to each Unit or designated as a common expense attributable to both Units. In each calendar month, each Owner's respective share of these expenses shall be proportionate to each Owner's dispatch of the applicable Unit, or both Units in the case of common expenses, over the previous sixty (60) calendar months.

(c) In each calendar month, each Owner shall be responsible for 50% of all other Steam Power Generation Expenses (FERC Accounts 500 - 515) not addressed in Section 6.4(a) and Section 6.4(b). Administrative and General Expenses (FERC Accounts 920 – 935) shall be assigned to the Mitchell Plant through an annual wages and salaries allocator applied to monthly Administrative & General Expenses. Each Owner shall be responsible for 50% of this monthly amount; provided, however, that, for the avoidance of doubt, each Owner shall be individually responsible for any fees, costs or other charges, including but not limited to those imposed by PJM Interconnection, L.L.C. ("PJM") or any regional transmission operator or any other Governmental Authority in respect of, or which are attributable to, the sale or transmission of the capacity or energy associated with its Ownership Interest, as the case may be.

(d) Notwithstanding the foregoing clauses (a) through (c) or anything else in this Agreement or the O&M Agreement to the contrary, in each calendar month, any operations and maintenance or other expenses to the extent attributable to any ELG Upgrade (regardless of the FERC Account to which it is charged) shall be allocated exclusively to and paid by WPCo.

(e) In each calendar month, each Owner's respective share of Construction Work In Progress charged to FERC Account 107 shall be allocated on the same basis as capital expenditures, as set forth in Section 6.7.

(f) In each calendar month, the net change in Mitchell Plant storeroom inventory (inventory purchases less issuances of inventory) charged to FERC Account 154 shall be allocated 50% to each Owner.

(g) Each Owner shall be charged 50% of Operating Costs, as defined in and in accordance with Section 7.2 of the O&M Agreement, except to the extent a different allocation for specific FERC Accounts or otherwise is specified in this Article Six.

6.5 All taxes, duties or assessments levied against or with respect to each Owner's Ownership Interest, or an Owner's purchase, use, ownership or beneficial interest in, or income from, the Mitchell Plant shall be the sole responsibility of, and shall be paid by, the Owner upon whose purchase, use, ownership interest or beneficial interest or income said taxes or assessments are levied. Without limiting the foregoing, in each calendar month, each Owner's respective share of Employee Payroll Taxes charged to FERC Account 408 shall be 50%.

6.6 Notwithstanding any other provision of this Agreement or any other agreement to the contrary, each Owner hereby acknowledges and agrees that (a) each Owner prior to the Effective Date has treated, and subsequent to such date shall continue to treat, the co-ownership and operation of the Mitchell Plant as excluded from Subchapter K of the Internal Revenue Code of 1986, as amended (the "Tax Code"), pursuant to Section 761(a) thereof, for all federal, state and local income tax purposes, (b) each Owner prior to the Effective Date affirmatively elected not to apply any of the provisions of Subchapter K of the Tax Code to such Owner's interest in the Mitchell Plant, with such election having been formally filed in connection with the Owners' applicable income tax returns for the taxable year ending on December 31, 2020 and each Owner has taken all actions necessary to implement such election and (c) each Owner prior to the Effective Date has reported, and subsequent to such date shall report, its share of all income, gains, deductions, losses, credits, etc. from its Ownership Interest on its tax returns consistent with such exclusion from the provisions of Subchapter K of the Tax Code.

6.7 Subject to clauses (b) and (c) below the cost of any replacement, addition, improvement or upgrade of each Unit or any portion of the Mitchell Plant, and any restoration or remediation required in connection therewith, shall be allocated between the Owners in accordance with the allocations for such capital items contained in the Capital Budget. With respect to any such capital item not contained in the Capital Budget, the costs of such capital item shall be allocated as follows, unless the Operating Committee agrees upon a different allocation:

(a) Capital expenditures (other than ELG Expenses) that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be allocated exclusively to, and paid for by, that Owner.

(b) Notwithstanding anything to the contrary herein, ELG Expenses shall be allocated exclusively to, and paid for exclusively by, WPCo (subject to adjustment of the Buyout Price in accordance with Section 9.6); provided that, to the extent that ELG Upgrades are also used to satisfy, or result in reduced capital expenditures to comply with, the CCR Rule, KPCo shall be allocated its equitable share of ELG Expenses associated with such ELG Upgrades. The Operating Committee shall engage or retain a Technical Expert to make recommendations with respect to

KPCo's equitable share of ELG Expenses to be allocated to KPCo in accordance with this Section 6.7(b).

(c) Notwithstanding anything to the contrary herein, if the in-service date of a capital item is reasonably anticipated by the Operating Committee to be after December 31, 2028, then the capital expenditures for such capital item shall be allocated exclusively to, and paid for by, WPCo.

(d) If the Operating Committee determines, including based on Depreciable Lives of similar assets previously approved by applicable Governmental Authorities, that a capital item (other than an ELG Upgrade) has a Depreciable Life that extends beyond December 31, 2028, then (i) KPCo shall be responsible for and shall pay 50% of the expenditures for such capital item, multiplied by (A) the number of months (not to exceed the Depreciable Life of such capital item) between the reasonably anticipated in-service date of such capital item and December 31, 2028, divided by (B) the Depreciable Life of such capital item and (ii) WPCo shall be responsible for the remaining amount of such capital expenditure not allocated to KPCo pursuant to the foregoing clause (i).

(e) Any other capital expenditures shall be allocated 50% to each Owner, subject to the written approval of the Operating Committee for budget overruns to the extent required pursuant to Section 5.3.2 of the O&M Agreement.

6.8 In the event of an Early Retirement Event, each Owner shall be responsible for 50% of all Decommissioning Costs, unless a different allocation is expressly specified for such item in the Capital Budget (as agreed by the Owners) or the Owners mutually agree to allocate such costs in another manner; provided that nothing in this Section 6.8 shall affect the inclusion of Decommissioning Costs in the calculation of the Buyout Price pursuant to Section 9.6.

6.9 Notwithstanding anything contained in this Agreement, an Owner's obligation to pay its obligations under this Agreement shall not in any way be conditioned upon or affected by any regulatory order or other determination disallowing, limiting or deferring rate recovery of the costs and expenses paid or payable by an Owner in respect of its Ownership Interest.

## ARTICLE SEVEN
## OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, each Owner shall name one representative (the "Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement and the O&M Agreement. An Owner may change its Operating Representative or alternate at any time by written notice to the other Owner. The Operating Representatives for the respective Owners, or their alternates, shall comprise the "Operating Committee". All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. If the Operating Representatives are unable to agree on any matter, such matter will be resolved through the dispute resolution procedures set forth in Article Twelve.

7.2 The Operating Committee shall have the following responsibilities, which decisions are reserved exclusively for the Operating Committee and may not be made individually by the Operator or any Owner:

(a) Review and approval of any amendments to the Capital Budget, and adoption of an annual operating budget, annual operating plan and a six-year forecast of operating and capital expenses, each as delivered to the Operating Committee by the Operator pursuant to Section 7.8, including determination of the emission allowances required to be acquired by each Owner with respect to their Ownership Interests; provided, that an Owner's Operating Representative shall have the right to amend the Capital Budget solely to include any capital expenditures for which such Owner shall be allocated greater than 75% of the costs pursuant to Section 6.7, up to an aggregate amount of such capital expenditures that does not exceed $5 million per year allocated to the other Owner. Allocations of new capital expenditures added to the Capital Budget shall be consistent with Section 6.7; provided, that if the Operating Committee cannot agree upon the Depreciable Life of a capital item or the allocation of a capital expenditure between the Owners (including the equitable allocation of any ELG Expense not fully allocated to WPCo), the matter shall be resolved in accordance with the Technical Dispute resolution procedures set forth in Section 12.1 and Section 12.3 and the Owners shall implement any resolution of the Technical Dispute through adjustments or true-up payments, as appropriate. If the Operating Committee fails to adopt an annual operating budget, the approved annual operating budget from the previous year (other than one-time or other non-recurring or inapplicable items) shall apply until such time as the new annual operating budget is approved.

(b) Establishment, modification and review of procedures, guidelines and systems for scheduling and dispatch, notification of dispatch, and Unit commitment under this Agreement, including any Unit-commitment pursuant to Section 7.5 or Section 7.6

(c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages at the Mitchell Plant, as well as the return the Mitchell Plant to availability following an unplanned outage. The Operating Committee shall use commercially reasonable efforts, consistent with Prudent Operation and Maintenance Practices (as defined in the O&M Agreement), to schedule the implementation of ELG Upgrades during planned maintenance and repair outages so as to eliminate or minimize incremental outages.

(d) To the extent not included in the Capital Budget, decisions on capital projects, including Unit upgrades and re-powering, except that an Owner's Operating Representative shall have the right to approve any such capital projects for which such Owner shall be allocated greater than 75% of the costs pursuant to Section 6.7 and Section 7.2(a).

(e) Determinations as to allocations between the Owners of expenses pursuant to Section 6.1.

(f) Engagement or retention of a Technical Expert to make recommendations with respect to KPCo's equitable share of ELG Expenses to be allocated to KPCo in accordance with Section 6.7(b).

(g) Determinations as to changes in the Unit capability.

(h) Establishment and modification of billing procedures under this Agreement or under the O&M Agreement.

(i) Approval of material contracts for fuel supply or transportation.

(j) Establishment and modification of specifications of fuels; oversight of fuel procurement, inspection and certification arrangements, policies and procedures; and management of fuel inventories for the Mitchell Plant.

(k) Establishment of, termination of, and approval of any change or amendment to the operating arrangements (including the O&M Agreement) between the Owners and the Operator (or any successor Operator or replacement third-party Operator) and selection of any replacement Operator, except as otherwise permitted by Section 7.10.

(l) Review and approval of plans and procedures designed to ensure compliance at the Mitchell Plant with all Applicable Law, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one Unit for compliance.

(m) Amendment, termination, extension or modification of the O&M Agreement, and supervision of the performance of, and provision of direction as needed to, the Operator.

(n) Decisions regarding the retirement, permanent removal from service or Decommissioning of a Unit or any material portion of the Mitchell Plant and any restoration or remediation required in connection therewith.

(o) Establishment of an insurance program to provide property and general liability insurance on behalf of each Owner, to be procured by the Operator pursuant to the O&M Agreement.

(p) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least quarterly, or at such other frequency as determined by the Operating Committee, and at such other times as an Owner may reasonably request. The Operator shall provide operations reports to the Operating Committee each month (presented on a monthly basis) and each quarter (presented on a quarterly basis) substantially in the form of Exhibit B hereto.

7.4 The Owners and the Operator shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 Subject to Section 7.6, each Unit shall be scheduled and dispatched on a joint and equal basis by the Owners, including bidding the Mitchell Plant or any Unit as a single bid, consistent with procedures and guidelines established by the Operating Committee. The Owners shall make an initial Unit-commitment one business day ahead of real-time dispatch, or on such other timetable as the Operating Committee may determine. In each calendar month, each Owner's respective shares of the Emissions Allowances consumed as determined in accordance with the provisions of Section 7.7 shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

7.6 In the event an Owner desires to separately schedule and dispatch any Unit, subject to the receipt of any necessary regulatory approvals or waivers, the Operating Committee shall establish and implement procedures and systems for separate scheduling and dispatch by each Owner, consistent with all of the requirements of any Person or regional transmission organization, such as PJM, supervising the collective transmission or generation facilities of the power region in which the Mitchell Plant is located that is charged with coordination of market transactions, system-wide transmission planning and network reliability.

7.7 Emission Allowances. To the extent that emission allowances issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Cross-State Air Pollution Rule 40 C.F.R. Part 97, and any amendments thereto (the "Emission Allowances"), are required for operation of the Mitchell Plant, each Owner will be entitled to receive for its own benefit 50% of any Emissions Allowances allocated to the Mitchell Plant. Each Owner will be responsible for acquiring any additional Emission Allowances needed to satisfy the Emission Allowances required because of such Owner's dispatch of energy from the Mitchell Plant. Additionally, each Owner will be responsible for acquiring the Emission Allowances required, to the extent necessary in addition to its share of the Emissions Allowances allocated to the Mitchell Plant, to satisfy 50% of the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al*., Civil Action Nos. C2-99-1182 and C2-99-1250 and *United States, et al. v. American Electric Power Service Corp., et al., Civil Action No. C2-05-360 and Ohio Citizen Action, et al. v. American Electric Power Service Corp.*, Civil Action No. C2-04-1098 dated December 10, 2007 as subsequently modified or amended, it being understood that the Owners may be subject to additional rights and obligations under any applicable agreement among the Owners (and/or their Affiliates) and American Electric Power Company, Inc. (and/or its Affiliates) pertaining to the allocation of emission limitations associated with the Mitchell Plant. As early as possible, but no later than three business days after the deadline for submitting final electronic data to the EPA for compliance purposes, the Operator shall notify each Owner of the number of annual or seasonal Emission Allowances that are needed to offset each Owner's share of emissions for the previous year or season. Each Owner shall supply its respective share of allowances, with a reasonable compliance margin as determined by the Operating Committee, by transferring the applicable allowances to the Mitchell Plant's Allowance Facility Account on or before 15 days prior to the remittance date. In the event that an Owner fails to surrender the required number of Emission Allowances in accordance with the prior paragraph, the other Owner shall have the option to purchase the required number of Emission Allowances, and the Owner that failed to surrender the required number of Emission Allowances shall reimburse the other Owner for any amounts it shall have incurred to make such purchases, with interest at the "Federal Funds Rate" (as published by the Board of Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for each Owner's share of the Emission Allowances required by the use of the Mitchell Plant and to correct any imbalance between the Emission Allowances supplied and the Emission Allowances used through the end of the preceding year by settlement or payment.

7.8 At least ninety (90) days before the start of each operating year, the Operator shall submit to the Operating Committee any proposed amendments to the Capital Budget and an annual operating budget for such operating year with respect to the Mitchell Plant, a proposed annual operating plan with respect to the Mitchell Plant for such operating year, and a forecast of operating and capital costs to be incurred during the next six-year period. The annual operating budget and amendments to the Capital Budget shall be presented on a month-by-month basis, and shall include an operating budget, a capital budget, and an estimate of the cost of any major repairs or improvements that are anticipated to occur during the relevant period with respect to the Mitchell Plant, and an itemized estimate of all projected fixed and variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual operating budget, final annual operating plan and any amendments to the Capital Budget. Once approved, the annual operating budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine. If an Early Retirement Event occurs, the members of the Operating Committee will meet and work in good faith to amend the Capital Budget to remove any future ELG Expenses and any other future capital expenditures no longer required, to the extent practicable and consistent with Applicable Law. The Capital Budget shall remain in effect throughout the Term, subject to such amendments as the Operating Committee may determine.

7.9 Notwithstanding anything in this Agreement to the contrary, in the case of the O&M Agreement or any other agreement relating to the Mitchell Plant that is entered into jointly by or on behalf of the Owners, on one hand, with an Affiliate of an Owner (or with an Owner itself, as in the case of the O&M Agreement) on the other hand, the non-Affiliate Owner shall have the sole and exclusive right to exercise any and all affirmative or elective rights of the Owners, including remedies (including delivering notices of and pursuing or settling disputes or delivering notices of default or making and pursuing claims for indemnification) and any termination rights (including rights of termination for convenience, if any) thereunder (for the avoidance of doubt, without first obtaining the consent of the other Owner or the Operating Committee); provided, however, that notice of any such action described in this Section 7.9 shall be sent to the other Owner at the time such action is taken if such other Owner is not the Operator. For purposes of this Agreement, "Affiliate" shall mean, with respect to any person or entity, any other person or entity that directly or indirectly, controls, is controlled by, or is under common control with such person or entity. As used in this definition, "control" (including, with its correlative meanings, "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a person or entity, whether through the ownership of securities or partnership or other ownership interests, by contract or otherwise.

ARTICLE EIGHT
EFFECTIVE DATE AND TERM

8.1 This Agreement shall be effective as of the Effective Date.

8.2 Subject to FERC approval or acceptance of any termination, if necessary, this Agreement shall remain in force until the earlier of (a) the date on which this Agreement is terminated by mutual agreement of the Owners or (b) the consummation of the Buyout Transaction contemplated by Section 9.6 (the period from the Effective Date through such date, the "Term").

ARTICLE NINE
TRANSFERS

9.1 Neither Owner may assign, transfer or otherwise dispose of its Ownership Interest, either in whole or part, whether by sale, lease, division, declaration or creation of a trust, by operation of law or otherwise ("Dispose" or a "Disposition") to any person or entity (the "Proposed Purchaser") without the prior written consent of the other Owner (the "Non-Offering Owner" and the Owner proposing the Disposition, the "Offering Owner"), which consent may be granted or withheld in the Non-Offering Owner's sole discretion; provided, that, the foregoing shall not restrict the Owners from pursuing or consummating the Buyout Transaction. Notwithstanding the foregoing, either Owner may Dispose of, all (but not less than all) of its Ownership Interest to a state regulated utility Affiliate, provided that (i) the Disposition shall not relieve the Offering Owner of its obligations under this Agreement, (ii) the Disposition shall be made in compliance with the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-99-1182 and C2-99-1250 and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360, and all amendments or modifications thereto, as in effect as of the date of the Disposition, (iii) the Proposed Purchaser shall agree to and assume, in respect of the Ownership Interest subject to the Disposition, the rights and obligations of the Offering Owner and its Affiliates under any applicable agreement with American Electric Power Company, Inc. (and/or its Affiliates) pertaining to the allocation of emission limitations associated with the Mitchell Plant, and (iv) in the event the Offering Owner (or any Affiliate thereof) shall be the Operator, the Proposed Purchaser shall also have been assigned, and agreed to have assumed, the rights and obligations of the Operator under this Agreement and the O&M Agreement as of the effective date of such Disposition; provided, that in the case of this clause (iv), a written consent from the Non-Offering Owner (which consent shall not be unreasonably withheld, conditioned or delayed) shall be obtained prior to such Disposition to the extent such Disposition results in the change of the Operator.

9.2 No Disposition shall be made unless all requisite regulatory and other approvals, consents and authorizations from all Governmental Authorities that are required to be obtained in connection with such Disposition have been obtained and as to which all conditions to the consummation of Disposition thereunder have been satisfied.

9.3 Subject to Section 9.6, all costs associated with any Disposition of an Ownership Interest by an Owner shall be borne solely by the Offering Owner, provided that the foregoing shall not limit the Offering Owner's right to seek reimbursement of any costs from the Proposed Purchaser in connection with any such Disposition.

9.4 Each Owner shall have the right to seek financing for all or a portion of such Owner's Ownership Interest and to provide general security for such financing of its Ownership Interest, including through the creation of any Encumbrance thereon (and the right of the beneficiary thereof to enforce thereon, but not to foreclose upon or transfer such Owner's Ownership Interest without the prior written consent of the other Owner), without the prior consent of the other Owner; provided that neither Owner may enter into any financing agreement or create any Encumbrance that would be reasonably likely to prohibit or otherwise restrict or condition the Buyout Transaction contemplated by Section 9.6. Each Owner further agrees to cooperate reasonably and in good faith, and to cause its Affiliates to so cooperate, with an Owner seeking financing in connection with such modifications and other rights and consents customary in transactions of such type, and not unreasonably to withhold its consent to such modifications as may be reasonably necessary or appropriate to allow such Owner to obtain such financing upon reasonably competitive terms, including obtaining consents to the assignment of such Owner's Ownership Interest in any of the Project Assets reasonably requested by such Owner's lender; provided that none of such proposed modifications shall (a) relieve the financing Owner of any of its obligations under this Agreement, the O&M Agreement or any other agreement related to the Mitchell Plant or any Project Asset, (b) decrease the economic benefits, or increase the costs, of the ownership and operation of the Mitchell Plant to the other Owner, (c) create any increased economic or legal risk to the other Owner in connection with the ownership and operation of the Mitchell Plant, (d) permit or allow any Encumbrances relating to any such financing to be placed upon any portion of or interest in the Project Assets other than the financing Owner's Ownership Interest, (e) permit partition of the Project Assets or any of them, including any partition upon a default by the financing Owner under any of the relevant financing documents or (f) prohibit or otherwise restrict or condition the Buyout Transaction as contemplated by Section 9.6.

9.5 Notwithstanding anything else herein to the contrary, no Disposition shall constitute a release of the Offering Owner from any liabilities to the Non-Offering Owner or the Operator arising from events occurring prior to or in connection with the Disposition, except as may be set forth expressly in the Mitchell Interest Purchase Agreement.

9.6 Buyout Transaction. Unless an Early Retirement Event occurs, the Owners shall enter into the Mitchell Interest Purchase Agreement pursuant to which KPCo shall sell, transfer and assign to WPCo, and WPCo shall purchase and assume from KPCo, all of KPCo's Ownership Interest (the "KPCo Interest") (including its interest in the underlying land, common facilities, barge unloading and gypsum conveyor facilities, and inventory and spare parts with respect to the Mitchell Plant), with the closing of such transaction to occur on December 31, 2028 (or such earlier date as may be mutually agreed by the Owners), subject to and in accordance with the provisions of this Section 9.6. The transactions contemplated by this Section 9.6 shall be referred to herein collectively as the "Buyout Transaction."

(a) Buyout Price. The purchase price for the KPCo Interest shall be (i) an amount mutually agreed by the Owners and approved by each of the WVPSC and the KPSC or, (ii) if no such amount is agreed by the Owners prior to June 30, 2027, an amount equal to (A) the Adjusted Fair Market Value of the KPCo Interest as of the closing date of the consummation of the Buyout Transaction, minus (B) the Decommissioning Costs Amount, plus (C) the Coal Inventory Adjustment (such aggregate amount, the "Buyout Price"). The Coal Inventory Adjustment and the CapEx Adjustment shall be subject to a customary closing estimation and post-closing true-up mechanism to be set forth in the Mitchell Interest Purchase Agreement.

(b) Determination of Fair Market Value. Not later than June 30, 2026, the Owners shall commence discussions to determine mutually agreed amounts for the Fair Market Value for the KPCo Interest and the Decommissioning Costs Amount. Unless prior to June 30, 2027, (i) the Fair Market Value for the KPCo Interest (or other alternative Buyout Price) has been mutually agreed by the Owners pursuant to this Section 9.6 or (ii) an Early Retirement Event has occurred, then not later than July 31, 2027, each Owner shall deliver a written notice to the other Owner appointing a nationally or regionally recognized appraisal firm, which is not an Affiliate of either Owner, with experience valuing coal-fired electric generating facilities that are comparable in size and scope to the Mitchell Plant ("Appraiser"), the costs and expenses of which shall be borne by the Owner appointing such Appraiser. Each of the Appraisers selected by WPCo and KPCo, respectively, shall work together to select a third Appraiser within fifteen (15) days of selection of the first two Appraisers or, if such first two Appraisers fail to agree upon the appointment of a third Appraiser, such appointment shall be made by the American Arbitration Association, or any successor organization thereto. The costs and expenses of the third Appraiser shall be borne equally by the Owners. Each Owner shall cooperate with each Appraiser and timely provide information and access to the Mitchell Plant facilities (including, subject to any confidentiality restrictions, contracts and financial information) and personnel as may be reasonably needed to complete its appraisal. The Fair Market Value of the KPCo Interest shall be calculated by the Appraisers as of December 31, 2028 (or such earlier date of the anticipated closing of the Buyout Transaction), assuming that the Units would permanently cease operations as of December 31, 2040 (or such earlier anticipated date as may have been filed by WPCo with the WVPSC) but without taking into account any Decommissioning Costs or the value of the common coal pile. Each Appraiser shall prepare a detailed written appraisal of the Fair Market Value of the KPCo Interest within sixty (60) days after the selection of such third Appraiser and provide its valuation reports to each of the Owners. If the Fair Market Value determined by one of the three Appraisers deviates from the Fair Market Value determination of the middle Appraiser by more than twice the amount by which the Fair Market Value determination of the other Appraiser deviates from the Fair Market Value determination of the middle Appraiser, then the Fair Market Value determination of such Appraiser shall be excluded, the remaining two Fair Market Value determinations shall be averaged, and such average shall be the Fair Market Value, which shall be binding and conclusive on the Owners; otherwise the average of all three Fair

Market Value determinations shall be the Fair Market Value, which shall be binding and conclusive on the Owners.

(c) Determination of Decommissioning Costs Amount. Unless prior to June 30, 2027, (i) the Decommissioning Costs Amount (or other alternative Buyout Price) has been mutually agreed by the Owners pursuant to this Section 9.6 or (ii) an Early Retirement Event has occurred, then not later than July 15, 2027, each Owner shall deliver a written notice to the other Owner appointing a nationally or regionally recognized engineering or consulting firm, which is not an Affiliate of either Owner, with experience decommissioning (or arranging decommissioning liability transfer arrangements for) coal-fired electric generating facilities that are comparable in size and scope to the Mitchell Plant ("Qualified Firm"), the costs and expenses of which shall be borne by the Owner appointing such Qualified Firm. Each of the Qualified Firms selected by WPCo and KPCo, respectively, shall work together to select a third Qualified Firm within fifteen (15) days of selection of the first two Qualified Firms or, if such first two Qualified Firms fail to agree upon the appointment of a third Qualified Firm, such appointment shall be made by the American Arbitration Association, or any successor organization thereto. The costs and expenses of the third Qualified Firm shall be borne equally by the Owners. Each Owner shall cooperate with each Qualified Firm and timely provide information and access to the Mitchell Plant facilities (including, subject to any confidentiality restrictions, contracts and financial information) and personnel as may be reasonably needed to complete its determination. The Decommissioning Costs Amount shall be calculated by the Qualified Firms as of December 31, 2028 (or such earlier date of the anticipated closing of the Buyout Transaction), assuming for purposes of such determination (A) the Units would permanently cease operations, and Decommissioning of the Mitchell Plant would commence, as of such date, (B) the Mitchell Plant facilities would be dismantled and removed from the Mitchell Plant site, (C) the Mitchell Plant site would be remediated to a legally permissible industrial use standard, (D) all legal obligations and commitments to Governmental Authorities in connection with the Decommissioning of the Mitchell Plant would be appropriately addressed and satisfied, and (E) such additional or alternative assumptions as the Operating Committee may determine. Each Qualified Firm shall prepare a detailed written determination of the Decommissioning Costs Amount within ninety (90) days after the selection of such third Qualified Firm and provide its determination reports to each of the Owners. If the Decommissioning Costs Amount determined by one of the three Qualified Firms deviates from the Decommissioning Costs Amount determination of the middle Qualified Firm by more than twice the amount by which the Decommissioning Costs Amount determination of the other Qualified Firm deviates from the Decommissioning Costs Amount determination of the middle Qualified Firm, then the determination of such Qualified Firm shall be excluded, the remaining two Decommissioning Costs Amount determinations shall be averaged, and such average shall be the Decommissioning Costs Amount, which shall be binding and conclusive on the Owners; otherwise the average of all three Decommissioning Costs Amount determinations shall be the Decommissioning Costs Amount, which shall be binding and conclusive on the Owners.

(d) Buyout Procedures. Unless an Early Retirement Event has occurred, the Owners shall cooperate in good faith to negotiate and execute the Mitchell Interest Purchase Agreement not later than December 31, 2027, including completing any applicable disclosure schedules and exhibits, consistent with the terms and conditions described in this Section 9.6, so that any applicable regulatory or other approvals shall be timely obtained so as to allow the Buyout Transaction to be consummated on or prior to December 31, 2028.

ARTICLE TEN
DEFAULTS AND REMEDIES

10.1 An Owner shall be deemed to be in default hereunder upon the occurrence of any of the following events with respect to such Owner (each of the following events to be referred to as an "Event of Default," the Owner in default to be referred to as the "Defaulting Owner" and the Owner not in default to be referred to as the "Non-Defaulting Owner"):

(a) an Owner fails to make any payment required by it as and when due and payable in accordance with the terms of this Agreement, the O&M Agreement or any other agreement related to the Mitchell Plant or any Project Asset and such failure is not remedied within ten (10) days after receipt of written notice thereof by such Owner from the other Owner; provided, that any such notice shall include a statement of the amount the Defaulting Owner has failed to pay (a "Payment Default"); or

(b) an Owner fails to perform any material obligation (other than as described in Section 10.1(a)) imposed upon such Owner under this Agreement and such failure is not remedied within thirty (30) days after such Owner receives written notice thereof from the other; provided that, if such thirty (30) day period is not sufficient to enable the remedy or cure of such failure in performance, and such Owner shall have upon receipt of the initial notice promptly commenced and diligently continues thereafter to remedy such failure, then such Owner shall have a reasonable additional period of time (but in no event longer than an additional ninety (90) days from the end of the initial thirty (30) day cure period) to remedy or cure such failure; provided, however, that an Owner shall not be in default of its obligations hereunder to the extent such failure is caused by or is otherwise attributable to a breach by the other Owner of its obligations under this Agreement.

10.2 Without limiting the rights and remedies available to the Non-Defaulting Owner under Applicable Law, in the case of an Event of Default, the Non-Defaulting Owner shall have the right (but not the obligation) to (x) pay all or a portion of the amounts that were the subject of the Payment Default on behalf of the Defaulting Owner and (y) perform the obligation(s) which the Defaulting Owner has failed to perform on behalf of and at the expense of the Defaulting Owner (in any such case subject to all limits on liability benefiting the Defaulting Owner as set forth in this Agreement); and, if such payment is made (the portion as so paid or expended in connection with such performance, the "Paid Amount"), to:

(a) charge the Defaulting Owner interest with respect to the Paid Amount, from the day the payment was made by the Non-Defaulting Owner until it is paid in full by the Defaulting Owner to the Non-Defaulting Owner, at the rate equal to the prime rate as published from time to time in *The Wall Street Journal* (or any successor publication) plus five (5) percentage points per annum, calculated daily, regardless of whether the Non-Defaulting Owner has notified the Defaulting Owner in advance of its intention to charge interest with respect to such Paid Amount;

(b) set off against the Paid Amount any sums due or accruing to the Defaulting Owner by the Non-Defaulting Owner in accordance with this Agreement;

(c) maintain an action or actions for the Paid Amount and interest thereon on a continuing basis as the Paid Amount becomes payable but is not paid by the Defaulting Owner, as if the obligation to pay those amounts and the interest thereon was a liquidated demand due and payable on the date the amounts were due to be paid, without any right or resort of the Defaulting Owner to set-off or counter-claim against the Non-Defaulting Owner; and any obligation to pay interest under this Section 10.2 shall apply until the Payment Default is rectified or remedied; and

(d) at the Non-Defaulting Owner's option, (i) draw on any letter of credit posted by the Defaulting Owner pursuant to Section 4.3 in an amount equal to the Paid Amount, including all interest accrued thereon or (ii) receive one hundred percent (100%) of any revenues arising from or attributable to the sale of capacity, energy, ancillary services or other energy products from the Mitchell Plant that the Defaulting Owner would otherwise be entitled to receive in respect of its Assigned Capacity until the Non-Defaulting Owner receives an amount equal to the Paid Amount, including all interest accrued thereon, *plus* all costs of collection incurred in connection therewith, and the Owners shall cooperate with each other, the Operator, applicable Governmental Authorities (including in respect of securing any regulatory approvals) or other third parties (including lenders) as may be reasonably necessary to facilitate the Non-Defaulting Owner's right to be paid and receive the revenues attributable to the Defaulting Owner's Assigned Capacity until the applicable Paid Amount, including all interest accrued thereon and all costs of collection incurred in connection therewith has been paid to the Non-Defaulting Owner in full, including facilitating any appropriate changes in the applicable settlement accounts with respect to which market revenues are credited or paid by PJM or other applicable regional transmission organizations and executing any documents required to assign over such market revenues to the Non-Defaulting Owner.

## ARTICLE ELEVEN
## LIMITATION OF LIABILITY

11.1 Without limiting any other provision of this Agreement, each Owner's liability under this Agreement shall be limited to direct actual damages only. Such direct actual damages shall be the sole and exclusive remedy with respect to all claims arising under this Agreement and all other remedies or damages at law or in equity with respect to claims arising under this Agreement are waived, and unless expressly provided herein, no Owner shall be liable for consequential, punitive, incidental, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or in contract, under any indemnity provision or otherwise, with respect to claims arising under this Agreement. It is the intent of the Owners that the limitations herein imposed on remedies and the measure of damages be without regard to the cause or causes related thereto, including the negligence of any Owner, whether such negligence be sole, joint or concurrent, or active or passive. Notwithstanding anything herein to the contrary, the limitations set forth in this Section 11.1 shall not limit or preclude any indemnification obligations of an Owner pursuant to Article Ten of the O&M Agreement, including with respect to indemnification for third-party claims.

ARTICLE TWELVE
DISPUTE RESOLUTION

12.1 If either Owner believes that a dispute (including a Technical Dispute) has arisen as to the meaning or application of this Agreement, it shall submit a written description of the disputed matter to the Operating Committee, and shall provide a copy of that submission to the other Owner.

12.2 If the Operating Committee is unable to reach agreement on the resolution of a dispute not constituting a Technical Dispute submitted to the Operating Committee pursuant to Section 12.1 within thirty (30) days after the dispute is presented to it, the matter shall be referred to senior executive officers with the authority to resolve such dispute of each of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner may exercise any and all rights at law or equity at any time after the end of the thirty (30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

12.3 If the Operating Committee is unable to reach agreement on the resolution of a Technical Dispute submitted to the Operating Committee within ten (10) business days after such Technical Dispute is presented to it, then either Owner may refer such Technical Dispute to a Technical Expert. Within ten (10) business days following receipt of an Owner's notice referring a Technical Dispute to a Technical Expert, the Operating Representatives shall confer to agree upon a Technical Expert to hear the Technical Dispute. If the Owners are unable to agree upon the appointment of a Technical Expert, then at the end of such ten (10) business day period each Owner shall, within five (5) business days, notify the other Owner in writing of its designation of a proposed Technical Expert. The two proposed Technical Experts shall, within five (5) business days, select a Technical Expert (who may be one of the two Technical Experts designated by the Owners or another Technical Expert) and such Technical Expert shall hear the Technical Dispute. Each Owner shall be required to put forth and endorse one proposal, budget or solution, as the case may be, as its proposed resolution to the Technical Dispute, based on an agreed statement of the nature of the Technical Dispute and agreed facts surrounding such Technical Dispute. Each Owner's proposal, budget or solution shall be delivered to the Technical Expert and the other Owner no later than twenty (20) business days after the date of the notice of the Owner submitting the Technical Dispute to the Technical Expert. The Technical Expert shall be guided by consideration of (a) this Agreement, (b) all other agreements between the Owners relating to the Mitchell Plant, including the O&M Agreement and (c) Prudent Operation and Maintenance Practices (as defined in the O&M Agreement), and be required to select one of the proposals, budgets or solutions, as the case may be, and shall not be able to select any other proposal, budget or solution, except to the extent mutually agreed by the Owners. The Technical Expert shall render a decision resolving the matter within forty-five (45) days of the date of the notice of the Owner submitting such matter. The Technical Expert shall not award to either Owner any relief greater than that initially sought by such Owner. The decision of the Technical Expert shall be final and binding upon the Owners and not subject to appeal or review. The Owners shall bear equally all costs and expenses of the Technical Expert procedure and the Technical Expert shall not have the authority to award costs or attorneys' fees to either Owner. The Technical Expert shall act as an expert and not as an arbitrator and the provisions of the Federal Arbitration Act and the laws relating to arbitration shall not apply to the Technical Expert or the Technical Expert's determination or the procedure by which a determination is reached. Except as provided in Section 7.2(a), the Technical Expert's decision shall not in any event result in deviations from the agreed allocations of costs between the Owners as set forth in this Agreement.

12.4 Except as provided in this Article Twelve, the existence, contents, or results of any settlement negotiations or the results thereof under this Article Twelve may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any Governmental Authority having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with any proceeding under pledge of confidentiality.

12.5 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through an action at law or equity. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. §§ 791a et seq., as amended from time to time, and any proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of FERC proceedings. To the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed at law or equity to secure such a remedy, subject to any FERC decisions, findings, or orders.

12.6 If an Owner (the "Contesting Owner") contests in good faith any amount paid pursuant to the terms of this Agreement following receipt of the written notice of the other Owner delivered pursuant to Section 10.1(a), and any portion of such amount is determined or resolved (including pursuant to the dispute resolution procedures of this Article Twelve) to be in excess of the actual amount due pursuant to the terms of this Agreement, then the Contesting Owner may charge the other Owner interest with respect to such excess amount from the day the payment was made until it is repaid to the Contesting Owner, at the rate equal to the prime rate as published from time to time in *The Wall Street Journal* (or any successor publication) plus five (5) percentage points per annum, calculated daily, regardless of whether the Contesting Owner has notified the other Owner in advance of its intention to charge interest with respect to such excess amount, and the other Owner shall make payment in full in respect of such excess amount and interest within thirty (30) days of written demand therefor.

# ARTICLE THIRTEEN
# GENERAL

13.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and permitted assigns, but this Agreement may not be assigned by any signatory without the written consent of the other parties hereto or as permitted by Article Nine hereof.

13.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

13.3 The interpretation and performance of this Agreement is governed by and shall be construed in accordance with the laws of the State of New York, exclusive of the conflicts of law provisions thereof that would require the application of the laws of a different jurisdiction. Each Owner hereby agrees that any Action arising out of or relating to this Agreement brought by an Owner (or any of their respective successors or assigns) shall be brought and determined in any state or federal court sitting in the State of New York, within the Borough of Manhattan, City of New York, and the Owners hereby irrevocably submit to the exclusive jurisdiction of the aforesaid courts for themselves and with respect to their property, generally and unconditionally, with regard to any such Action arising out of or relating to this Agreement and the transactions contemplated hereby, and the appellate courts from any thereof in connection with any action arising out of or relating to this Agreement or any other agreement related to the Mitchell Plant or any Project Asset and the transactions contemplated hereby, and consents that any such action may be brought in such courts and waives any objection it may now or hereafter have to the venue of any such action in any such court or that such action was brought in an inconvenient court. EACH OWNER HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ALL RIGHTS TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING TO THIS AGREEMENT, THE O&M AGREEMENT, OR ANY OTHER AGREEMENT RELATED TO THE MITCHELL PLANT OR ANY PROJECT ASSET.

13.4 This Agreement supersedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories hereto or their representatives with respect to operation of the Mitchell Plant, including the Original Operating Agreement. Notwithstanding the foregoing, the amendment and restatement of the Original Operating Agreement effected hereby shall not relieve any party thereto of any undischarged obligation or liability of such party in respect of the period prior to the Effective Date under the Original Operating Agreement. This Agreement, together with the O&M Agreement (and any replacements thereof), constitutes the entire agreement of the signatories hereto with respect to the operation of the Mitchell Plant and the ownership thereof. The signatories hereto hereby agree that this Agreement shall amend the Original Operating Agreement to irrevocably remove AEPSC as a party thereto and, on and after the Effective Date, AEPSC shall no longer be a party thereto or hereto or entitled to rights, or subject to obligations, as a party to this Agreement; provided, however, that Operator shall be permitted to delegate any of its rights, duties and obligations under this Agreement and the O&M Agreement to AEPSC without the consent of KPCo, but without relieving Operator of any of its obligations hereunder.

13.5 No amendments or modifications of this Agreement are valid unless in writing and signed by duly authorized representatives of the Owners.

13.6 Each Owner shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
[______]
[______]

Attn: ______________________________

Phone: [______]

Email: [______]

WHEELING POWER COMPANY
[______]
[______]

Attn: ______________________________

Phone: [______]

Email: [______]

All notices shall be deemed to have been given (a) when personally delivered, (b) when transmitted (except if not a Business Day then the next Business Day) via electronic mail (provided that no error message or other notification of non-delivery is generated with respect to the intended recipient), (c) the day following the day (except if not a Business Day then the next Business Day) on which the same has been delivered prepaid to a reputable national overnight air courier service or (d) the third Business Day following the day on which the same is sent by certified or registered mail, postage prepaid, in each case to the respective parties hereto at the address set forth below, or at such other address as such Owner may specify by written notice to the other Owner (or at such other address for an Owner as shall be specified in a notice given in accordance with this Section 13.6). Each Owner may, by written notice to the other Owner, change the representative or the address to which such notices are to be sent.

13.7 This Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument, but all of such counterparts shall constitute for all purposes one agreement. Any signature hereto delivered by a party hereto by facsimile or other electronic transmission shall be deemed an original signature hereto.

13.8 Except as otherwise specifically provided, all fees, costs and expenses incurred by the parties hereto in negotiating this Agreement shall be paid by the party incurring the same, including legal and accounting fees, costs and expenses.

13.9 Any of the terms, covenants, or conditions hereof may be waived only by a written instrument executed by or on behalf of the Owners waiving compliance. No course of dealing on the part of any Owners, or its respective officers, employees, agents, accountants, attorneys, investment bankers, consultants or other authorized representatives, nor any failure by an Owner to exercise any of its rights under this Agreement shall operate as a waiver thereof or affect in any way the right of such Owner at a later time to enforce the performance of such provision. No waiver by any Owner of any condition, or any breach of any term or covenant contained in this Agreement, in any one or more instances, shall be deemed to be or construed as a further or continuing waiver of any such condition or breach or a waiver of any other condition or of any breach of any other term or covenant. The rights of the Owners under this Agreement shall be cumulative, and the exercise or partial exercise of any such right shall not preclude the exercise of any other right.

13.10 This Agreement shall be binding upon and inure to the benefit of the Owners and their respective successors and permitted assigns.

13.11 No Owner will issue, or permit any of its Affiliates, its or its Affiliate's directors, officers, employees, consultants, agents or other representatives to issue, any press releases or otherwise make, or cause any of its Affiliates, its or its Affiliate's directors, officers, employees, consultants, agents or other representatives to make, any public statements or other public disclosures with respect to this Agreement, or the transactions contemplated hereby without the prior written consent of the other Owner; provided, however, that the foregoing requirement to obtain prior written consent shall not apply where such release, statement or disclosure is deemed in good faith by the releasing or disclosing Owner to be required by Applicable Law or under the rules and regulations of a recognized stock exchange on which shares of such Owner (or any of its Affiliates) are listed, so long as prior to making any such release, statement or disclosure and to the extent legally permitted, the releasing or disclosing Owner shall provide prompt notice to the other Owner, consult the other Owner as to the form, contents and timing of such release or disclosure and, when available, provide a copy of such release, statement or disclosure containing such information to the other Owner.

13.12 If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Owners shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Owners as closely as possible in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

13.13 Each Owner acknowledges that it shall be inadequate or impossible, or both, to measure in money the damage to the Members if any of them or any transferee or any legal representative of any Owner fails to comply with any of the restrictions or obligations imposed by

Article Nine that every such restriction and obligation is material, and that in the event of any such failure, the Owners shall not have an adequate remedy at law or in damages. Therefore, each Owner consents to the issuance of an injunction or the enforcement of other equitable remedies against such Owner at the suit of an aggrieved party without the posting of any bond or other security, to compel specific performance of all of the terms of Article Nine and to prevent any Disposition in contravention of any terms of Article Nine, and waives any defenses thereto, including the defenses of: (i) failure of consideration, (ii) breach of any other provision of this Agreement and (iii) availability of relief in monetary damages.

## ARTICLE FOURTEEN
## DEFINITIONS

For all purposes of this Agreement (including the preceding sections and recitals), unless otherwise required by the context in which any defined term appears or otherwise defined in the body of this Agreement, capitalized terms have the meanings specified in this Article Fourteen. In this Agreement, unless expressly stated otherwise: (a) reference to any agreement (including this Agreement), document or instrument means such agreement, document or instrument as has been, or may be, amended, supplemented or otherwise modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (b) reference to any Applicable Law means such Applicable Law as has been, or may be, amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including rules and regulations, promulgated thereunder; (c) the singular includes the plural, as the context requires; (d) the terms "includes" and "including" mean "including, but not limited to"; (e) "Day" (regardless of capitalization) shall mean a calendar day, unless specifically designated as a Business Day or business day; (f) "Month" (regardless of capitalization) shall mean a calendar month; (vii) references to articles, sections and appendices mean the articles and sections of, and appendices to, this Agreement.

"Adjusted Fair Market Value" means any positive amount (if any, and zero otherwise) equal to (A) the Fair Market Value, minus (B) the CapEx Adjustment.

"AEPSC" shall have the meaning given to such term in the Preamble.

"Agreement" shall have the meaning given to such term in the Preamble.

"Applicable Law" shall mean all laws (including common law), statutes, codes, acts, treaties, ordinances, orders, judgments, writs, decrees, injunctions, rules, regulations, governmental approvals, permits, directives, and requirements of all Governmental Authorities (including with respect to the environment) having jurisdiction over an Owner, any other person or entity (as to that person or entity), this Agreement, any Project Asset or the Mitchell Plant, as applicable.

"Appraiser" shall have the meaning given to such term in Section 9.6(b).

"Assigned Capacity" shall have the meaning given to such term in Section 2.3.

"Buyout Price" shall have the meaning given to such term in Section 9.6(a).

"Buyout Transaction" shall have the meaning given to such term in Section 9.6.

"CapEx Adjustment" shall mean (a) 50% of any capital expenditures (or portion thereof), including ELG Expenses, to the extent funded by WPCo in an amount in excess of 50% of the total amount thereof on or prior to December 31, 2028, plus (b) an amount equal to the WACC for the amounts included in clause (a), applied to all of such amounts using the then-applicable WACC from the dates of funding through the closing date of the consummation of the Buyout Transaction.

"Capital Budget" shall have the meaning given to such term in Section 1.7.

"CCR Rule" means the Coal Combustion Residuals Rule, 40 CFR Part 257 (April 17, 2015, as amended), and any regulations thereunder promulgated by the USEPA or the State of West Virginia.

"CertainTeed Contract" shall mean that certain Supply Agreement dated March 11, 2005, by and between CertainTeed Gypsum West Virginia, Inc. (formerly BPB West Virginia Inc.) and KPCo (as assignee of Ohio Power Company), as amended by Amendment No. 2010-1 dated August 2, 2010, as further amended by Amendment No. 2012-1 dated February 20, 2012 and as further amended by Amendment No. 2013-1 dated June 5, 2013, as may be amended, amended and restated, supplemented or modified from time to time, and as may be assigned to Operator or an Affiliate of Operator.

"Coal Inventory Adjustment" shall mean the weighted-average cost of KPCo's investment in the common coal pile for the Mitchell Plant.

"Control" shall have the meaning given to such term in Section 7.10.

"Credit Rating" means with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt or deposit obligations (not supported by third party credit enhancements) by S&P or Moody's. If no rating is assigned to such entity's unsecured, senior long-term debt or deposit obligations by S&P or Moody's, then "Credit Rating" means the general corporate credit rating or long-term issuer rating assigned to such entity by S&P or Moody's. If an entity is rated by both S&P and Moody's and the ratings are at different levels, then "Credit Rating" means the lowest such rating.

"Decommission" or "Decommissioning" shall mean the retirement, dismantlement and permanent removal of the Units and other property, plant, and equipment comprising the Mitchell Plant, including any common facilities associated with each Unit that are to be permanently removed from service, the restoration of the Mitchell Plant site and the removal or remediation of any hazardous materials or other contaminated equipment, materials, coal ash or wastes associated therewith, in a manner that meets the requirements of Applicable Law.

"Decommissioning Costs" shall mean all costs and obligations expended or incurred in the performance of all work reasonably necessary or undertaken to Decommission the Mitchell Plant, including work associated with the preparation and implementation of Decommissioning plans and the preparation, submittal and prosecution of all necessary applications with Governmental Authorities as required to Decommission the Mitchell Plant in accordance with Applicable Law.

"Decommissioning Costs Amount" shall mean an amount equal to 50% of all Decommissioning Costs, as determined by and adjusted in accordance with the procedures and calculation criteria and factors set forth in the Section 9.6(c).

"Defaulting Owner" shall have the meaning given to such term in Section 10.1.

"Depreciable Life" means, with respect to a capital item, the shorter of (a) the reasonably expected depreciable life (in months) of such capital item and (b) the number of months between the anticipated in-service date of such capital item and December 31, 2040 (or such earlier anticipated date of the permanent cessation of operations of the Units filed with the WVPSC).

"Dispose" or "Disposition" shall have the meaning given to such term in Section 9.1.

"Early Retirement Event" shall mean the delivery of a written notice by WPCo to KPCo irrevocably committing to permanently cease operations of the Mitchell Plant effective on or, with KPCo consent, prior to December 31, 2028, which notice shall be consistent with WPCo's current filings at such time with the WVPSC in respect of the Mitchell Plant.

"Effective Date" shall have the meaning given to such term in the Preamble.

"ELG Expenses" shall mean all capital expenditures associated with implementation of the ELG Upgrades.

"ELG Rule" shall mean the Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650 (Oct. 13, 2020), and any regulations thereunder promulgated by the USEPA or the State of West Virginia.

"ELG Upgrades" shall mean any improvements or upgrades to the Mitchell Plant to comply with the ELG Rule.

"Emission Allowances" shall have the meaning given to such term in Section 7.7.

"Encumbrance" shall mean with respect to any property or asset (a) any mortgage, deed of trust, charge, lien, pledge, hypothecation, title retention arrangement or other security interest, as or in effect as security for the payment of a monetary obligation or the observance of any other obligation; (b) any easement, servitude, restrictive covenant, equity or interest in the nature of an encumbrance, garnishee order, writ of execution, right of set-off, lease, license to use or occupy, assignment of income or monetary claim, whether or not filed, recorded or otherwise perfected under Applicable Law; and (c) any agreement to create any of the foregoing or allow any of the foregoing to exist.

"Event of Default" shall have the meaning given to such term in Section 10.1.

"Fair Market Value" shall mean, with respect to the KPCo Interest as of any date, an amount (which may be a positive or a negative number) equal to 50% of the cash price obtainable in an arm's-length sale of the entirety of the Mitchell Plant between an informed and willing buyer and seller, in each case under no compulsion to buy or sell, as the case may be, as determined by and adjusted in accordance with the procedures and valuation criteria and factors set forth in Section 9.6(b).

"FERC" shall have the meaning given to such term in Section 5.1.

"FERC Accounting Requirements" means the accounting requirements of FERC, including with respect to the Uniform System of Accounts, established by FERC under the FPA.

"FPA" means the Federal Power Act.

"Governmental Authority" means any federal, national, regional, state, municipal or local government authority, tribunal, court, agency, body, board or instrumentality, or any regulatory, administrative or other department, commission, bureau or agency, taxing authority or power, or any political or other subdivision, department or branch of the foregoing, including any independent system operator, regional transmission organization or electric reliability organization.

"HSR Act" shall mean the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

"KPCo" shall have the meaning given to such term in the Preamble.

"KPCo Interest" shall have the meaning given to such term in Section 9.6.

"KPSC" shall mean the Kentucky Public Service Commission.

"Mitchell Interest Purchase Agreement" shall mean an asset purchase agreement between KPCo and WPCo to implement the Buyout Transaction at the Buyout Price, consistent with Section 9.6. The transferred assets and assumed liabilities transferred under the Mitchell Interest Purchase Agreement shall be consistent with the scope of those items set forth in the Asset Contribution Agreement (and related indemnity agreements) between AEP Generation Resources Inc. and WPCo (as successor by merger to Newco Wheeling Inc.), dated January 31, 2015, the form of which was approved by the WVPSC in WVPSC Case No. 14-0546-E-PC.

"Mitchell Plant" shall mean the Mitchell Power Generation Facility, which consists of the Units and associated plant, equipment, real estate and other related facilities, located in Moundsville, West Virginia, but excluding the real property and operation known as the Conner Run Fly Ash Impoundment and Dam.

"Moody's" shall have the meaning given to such term in Section 4.3.

"Non-Defaulting Owner" shall have the meaning given to such term in Section 10.1.

"Non-Offering Owner" shall have the meaning given to such term in Section 9.1.

"O&M Agreement" shall have the meaning given to such term in the Recitals.

"Offering Owner" shall have the meaning given to such term in Section 9.1.

"Operating Committee" shall have the meaning given to such term in Section 7.1.

"Operating Representative" shall have the meaning given to such term in Section 7.1.

"Operator" shall have the meaning given to such term in the Recitals.

"Original Operating Agreement" shall have the meaning given to such term in the Recitals.

"Owner" or "Owners" shall have the meaning given to such term in the Preamble.

"Ownership Interest" shall have the meaning given to such term in the Recitals.

"Paid Amount" shall have the meaning given to such term in Section 10.2.

"Payment Default" shall have the meaning given to such term in Section 10.1(a).

"Project Assets" shall have the meaning given to such term in Section 1.1.

"Proposed Purchaser" shall have the meaning given to such term in Section 9.1.

"Qualified Firm" shall have the meaning given to such term in Section 9.6(c).

"Ratings Requirement" shall mean a Credit Rating for such Owner (or if such Owner has provided a guaranty issued by an Affiliate to satisfy its obligations under this Section 4.3, such Owner's Affiliate guarantor) of at least "BBB-" by S&P or at least Baa3 by Moody's, and if such Credit Rating is "BBB-" by S&P or "Baa3" by Moody's then such Credit Rating must not be on negative credit watch by S&P or Moody's.

"S&P" shall have the meaning given to such term in Section 4.3.

"Tax Code" shall have the meaning given to such term in Section 6.6.

"Technical Dispute" shall mean any dispute which this Agreement expressly provides shall be a Technical Dispute.

"Technical Expert" shall mean any individual selected in accordance with the procedure specified in Section 12.3 and who (a) has significant professional qualifications and practical experience in the subject matter of the Technical Dispute, (b) has no interest, financial or otherwise, or duty which conflicts or may conflict with such individual's functions as a Technical Expert (such individual being required to fully disclose any such interest or duty prior to any appointment) and (c) is not currently and has not been (i) during the five (5) years prior to the date of appointment, an employee of any of the Owners or any of their Affiliates and (ii) during the three (3) years prior to the date of appointment, a contractor or consultant of either of the Owners or any of their Affiliates, unless otherwise mutually agreed by the Owners.

"Term" shall have the meaning given to such term in Section 8.2.

"Total Net Capability" shall have the meaning given to such term in Section 2.1.

"Total Net Generation" shall have the meaning given to such term in Section 2.2.

"Unit" shall have the meaning given to such term in the Recitals.

"USEPA" shall have the meaning given to such term in Section 7.7.

"WACC" shall mean, as of any date, WPCo's then-applicable WVPSC-authorized weighted average cost of capital, compounded semiannually.

"WPCo" shall have the meaning given to such term in the Preamble.

"WVPSC" shall mean the West Virginia Public Service Commission.

[*Signature pages follow*.]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: ___________________________________

Title:

WHEELING POWER COMPANY

By: ___________________________________
Title:

Solely with respect to Section 13.4:

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: ___________________________________
Title:

**Exhibit A**

**Capital Budget, Initial Budgets and Forecast**

[To Be Attached as of the Effective Date.]

**Exhibit B**

## Form of Monthly Sample Report

[Attached.]

# MITCHELL OPERATING COMMITTEE

## MINTUES

## November 2, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on November 2, 2021, at 8:00 a.m. (Eastern).

**Operating Representatives Present:**

> (1) Chris Beam, President and Chief Operating Officer, Wheeling Power Company; (2) Brett Mattison, President and Chief Operating Officer, Kentucky Power Company; and (3) Tim Kerns, VP Generating Assets, Fossil & Hydro Generation, American Electric Power Service Corporation.

Constituting all of the Operating Representatives. Also present were John Crespo, Christen Blend, Jim Bacha, Randy Ryan, Stephan Haynes, Matt Satterwhite, and Raja Sundararajan.

Mr. Crespo acted as Secretary of the meeting of the Operating Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives approved the Agenda for the meeting, attached.

Mr. Crespo, Secretary to the Operating Committee and legal counsel for AEP, presented the revised drafts of the proposed Mitchell Operation and Maintenance Agreement and the proposed Mitchell Ownership Agreement. AEP legal counsel also described the current status of the draft agreements as forms included in the transaction for the sale of Kentucky Power to Liberty, which will include the sale of Kentucky Power's undivided interests in the Mitchell Plant. The Operating Representatives engaged in general discussions regarding the proposed agreements and their terms and conditions. The Operating Representatives requested additional information from Legal Counsel regarding the proposed agreements.

There being no further business, the Operating Committee meeting was adjourned.

John Crespo

Secretary

# MITCHELL OPERATING COMMITTEE

## AGENDA

## November 2, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") will be held on November 2, 2021, at 8:00 a.m. (Eastern).

**Invitees**: Operating Representatives: Brett Mattison (Kentucky Power), Chris Beam (Wheeling Power), Tim Kerns (Agent), Mike Zwick (Agent – Alternate)

Other Invitees: John Crespo (Secretary), Christen Blend, Jim Bacha, Randy Ryan, Mathew Satterwhite, Raja Sundararajan, Randy Ryan, Stephan Haynes

1. **Call to Order**
   A. Roll Call for Quorum
   B. Review of Agenda

2. **Operating Agreement** – Legal Counsel
   A. Review and discussion of revised terms of draft Mitchell Operations and Maintenance Agreement and draft Mitchell Ownership Agreement.
   B Discussion of potential resolutions related to the proposed agreements.

3. **Other Business**

4. **Adjournment**



#2558499v1

**Exhibit C**
**[Final Form]**

# OPERATIONS AND MAINTENANCE AGREEMENT

by and between

**KENTUCKY POWER COMPANY, as the Non-Operator Owner**

and

**WHEELING POWER COMPANY, as the Operator**

Dated as of

[_________]

## TABLE OF CONTENTS

**Page**

# MITCHELL PLANT OPERATIONS AND MAINTENANCE AGREEMENT

This OPERATIONS AND MAINTENANCE AGREEMENT (this "Agreement"), dated as of [__________] (the "Effective Date"), is entered by and between WHEELING POWER COMPANY, a West Virginia corporation (in its capacity as the operator of the Facility, "Operator" and in its capacity as an owner of the Facility, "WPCo") and KENTUCKY POWER COMPANY, a Kentucky corporation qualified as a foreign corporation in West Virginia (in its capacity as an owner of the Facility, the "Non-Operator Owner" and, together with WPCo, each an "Owner" and, together, the "Owners").

## RECITALS

1. Owners each own an undivided Ownership Interest in the Facility (these and other capitalized terms are defined in Article II).

2. On the date hereof, WPCo and the Non-Operator Owner have entered into that certain Mitchell Plant Ownership Agreement, setting forth the respective rights, duties and obligations of the Owners with respect to each other and the Facility in their capacities as the Owners thereof (the "Ownership Agreement").

3. Pursuant to the Ownership Agreement, WPCo has agreed to manage the day-to-day operations and maintenance of the Facility as Operator pursuant to the terms of this Agreement.

4. Operator and the Non-Operator Owner desire to execute this Agreement to set forth the respective rights, duties and obligations of WPCo, in its capacity as Operator of the Facility, and the Non-Operator Owner, in its capacity as an Owner of an undivided interest as a co-tenant in the Facility.

NOW, THEREFORE, in consideration of the foregoing premises, and of the mutual covenants, undertakings and conditions set forth below, the Parties agree as follows:

## ARTICLE I - AGREEMENT

1.1 Agreement. This Agreement consists of the recitals, and the terms and conditions set forth in this Agreement, as well as the appendices that are referenced in the table of contents and attached to this Agreement.

1.2 Relationship of the Parties. Operator shall perform the Services in its capacity as an independent contractor of the Owners and as principal on its own behalf as an Owner. Subject to any limitations set forth in this Agreement and the Ownership Agreement, the Owners delegate to Operator, and Operator accepts from the Owners, the responsibility of providing the Services at the Facility. The Owners and Operator agree that the scope of delegation is strictly limited to the matters set forth in this Agreement and the Ownership Agreement. Without limiting the generality of the foregoing, the Owners retain the ultimate authority and obligation to determine whether and to what extent the Facility operates, and Operator shall not cause the Facility to generate power except as expressly directed to do so by the Owners or any dispatching authority specified by the Owners in accordance with the Ownership Agreement. For the avoidance of doubt, any provision of this Agreement requiring the delegation of authority, direction, consent or authorization with respect to the Owners shall mean the delegation, direction, consent or authorization of both Owners (or the Operating Committee) in accordance with the Ownership Agreement (except to the extent the Ownership Agreement gives exclusive authority to the Non-Operator Owner thereunder, in which case such delegation of authority, direction, consent or authorization with respect to the Owners shall mean exclusively the delegation, direction, consent or authorization of the Non-Operator Owner).

1.3 Entire Agreement. This Agreement, together with the Ownership Agreement, contains the entire agreement between the Parties with respect to Operator's provision of Services at the Facility and supersedes all prior negotiations, undertakings and agreements.

## ARTICLE II - DEFINITIONS

For all purposes of this Agreement (including the preceding sections and recitals), unless otherwise required by the context in which any defined term appears, capitalized terms have the meanings specified in this Article II. The singular includes the plural, as the context requires. The terms "includes" and "including" mean "including, but not limited to." The terms "ensure" and "reasonable efforts" will not be construed as a guarantee, but will imply only a duty to use reasonable efforts and care, consistent with Prudent Operation and Maintenance Practices, and will include reasonable expenditures of money and at least such efforts as Operator would undertake for its own assets, services or maintenance, or for services provided to an Affiliate. "Gross negligence" will not be construed as simple or ordinary negligence, it being the intent of the Parties to preserve a distinction between errors made inadvertently while attempting to perform with due care and actions taken with a knowing disregard for a foreseeable risk. "Day" (regardless of capitalization) shall mean a calendar day, unless specifically designated as a Business Day. "Month" (regardless of capitalization) shall mean a calendar month. References to articles, sections and appendices mean the articles and sections of, and appendices to, this Agreement, except where expressly stated otherwise.

"AEP" shall mean American Electric Power Company, Inc., a New York corporation and an Affiliate of WPCo.

"AEPSC" shall mean American Electric Power Service Corporation, a New York corporation and an Affiliate of WPCo.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly, controls, is controlled by, or is under common control with such Person. As used in this definition, "control" (including, with its correlative meanings, "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of securities or partnership or other ownership interests, by contract or otherwise. The Non-Operator Owner shall not be deemed an Affiliate of the Operator.

"Agreement" has the meaning set forth in the preamble to this Agreement.

"Applicable Law" means all laws (including common law), statutes, codes, acts, treaties, ordinances, orders, judgments, writs, decrees, injunctions, rules, regulations, Governmental Approvals, Permits, directives, and requirements of all Governmental Authorities (including with respect to the environment) having jurisdiction over an Owner, any other Person or entity (as to that Person or entity), this Agreement, any Facility asset or the Facility, as applicable.

"Bankruptcy" means a situation in which (i) a Person files a voluntary petition in bankruptcy or is adjudicated as bankrupt or insolvent, or files any petition or answer or consent seeking any reorganization, arrangement, moratorium, composition, readjustment, liquidation, dissolution or similar relief for itself under the present or future applicable United States federal, state or other statute or law relative to bankruptcy, insolvency or other relief for debtors, or seeks or consents to or acquiesces in the appointment of any trustee, receiver, conservator or liquidator of such Person or of all or any substantial part of its properties (the term "acquiesce," as used in this definition, includes the failure to file a petition or motion to vacate or discharge any order, judgment or decree within fifteen (15) days after entry of such order, judgment or decree); (ii) a court of competent jurisdiction enters an order, judgment or decree approving a petition filed against any Person seeking a reorganization, arrangement, moratorium, composition, readjustment, liquidation, dissolution or similar relief under the present or any future United States federal bankruptcy act, or any other present or future Applicable Law relating to bankruptcy, insolvency or other relief for debtors, and such Person acquiesces and such decree remains unvacated and unstayed for an aggregate of sixty (60) days (whether or not consecutive) from the date of entry thereof, or a trustee, receiver, conservator or liquidator of such Person is appointed with the consent or acquiescence of such Person and such appointment remains unvacated and unstayed for an aggregate of sixty (60) days, whether or not consecutive; (iii) a Person admits in writing its inability to pay its debts as they mature; (iv) a Person gives notice, to any Governmental Authority of insolvency or pending insolvency, or suspension or pending suspension of operations; or (v) a Person makes a general assignment for the benefit of creditors or takes any other similar action for the protection or benefit of creditors (other than in the ordinary course of such party's business).

"Budget" means an annual operating budget and annual capital budget adopted or amended pursuant to the Ownership Agreement.

"Business Day" means any day other than (i) a Saturday or Sunday or (ii) a day on which banks in West Virginia or Ohio are required or permitted to be closed.

"Claims" means any and all claims, assertions, demands, suits, investigations, inquiries, and proceedings.

"Confidential Information" means, with respect to each Party, all written or oral information of a proprietary, intellectual or similar nature, relating to the business, projects, operations, activities or affairs of a Party and its Affiliates, whether of a technical or financial nature or otherwise (including environmental assessment reports, financial information, business plans and proposals, ideas, concepts, trade secrets, know-how, processes, pricing of services or products, and other technical or business information, whether concerning this Agreement, each Party's respective businesses or otherwise) that has not been publicly disclosed and that the receiving Party acquires directly or indirectly from the disclosing Party.

"Cost Allocation Manual" means the Cost Allocation Manual of Operator and its Affiliates, as may be amended from time to time, as filed with FERC and, to the extent required, the WVPSC.

"Decommission" or "Decommissioning" shall mean the retirement, dismantlement and permanent removal of the generating units and other property, plant, and equipment comprising the Facility, including any common facilities associated with each generating unit that are to be permanently removed from service, the restoration of the Site and the removal or remediation of any hazardous materials or other contaminated equipment, materials, coal ash or wastes associated therewith, in a manner that meets the requirements of Applicable Law.

"Decommissioning Work" shall mean all work reasonably necessary or undertaken to Decommission the Facility, including work associated with the preparation and implementation of Decommissioning plans and the preparation, submittal and prosecution of all necessary applications with Governmental Authorities as required to Decommission the Facility in accordance with Applicable Law.

"Dollars" means United States Dollars, the lawful currency of the United States of America.

"Due Date" means, with respect to any Operator invoice, the date that is thirty (30) days following the date on which Operator submits the invoice to the Non-Operator Owner in accordance with Article VII. If such date does not fall on a Business Day, then the Due Date shall be the first Business Day after such date.

"Effective Date" means the date set forth in the preamble to this Agreement.

"Emergency" has the meaning set forth in Section 3.8.

"Encumbrance" means (i) any mortgage, charge, lien, pledge, hypothecation, title retention arrangement or other security interest, as or in effect as security for the payment of a monetary obligation or the observance of any other obligation; (ii) any easement, servitude, restrictive covenant, equity or interest in the nature of an encumbrance, garnishee order, writ of execution, right of set-off, lease, license to use or occupy, assignment of income or monetary Claim; and (iii) any agreement to create any of the foregoing or allow any of the foregoing to exist.

"Environmental Law" means any Applicable Law pertaining to (i) the regulation or protection of employee health or safety, public health or safety, or the indoor or outdoor environment; (ii) the conservation, management, development, control or use of land, natural resources, or wildlife; (iii) the protection or use of surface water or ground water; (iv) the management, manufacture, possession, presence, use, generation, treatment, storage, disposal, transportation, or handling of, or exposure to any Hazardous Material; or (v) pollution (including release of any hazardous substance to air, land, surface water and ground water), including the Comprehensive Environmental Response, Compensation, and Liability Act, as amended by the Superfund Amendments and Reauthorization Act of 1986 (42 U.S.C. §§ 9601 et seq.), the Hazardous Materials Transportation Act (49 U.S.C. §§ 1801 et seq.), the Resource Conservation and Recovery Act, as amended (42 U.S.C. §§ 6901 et seq.), the Toxic Substances Control Act (15 U.S.C. §§ 2601 et seq.), the Clean Water Act (33 U.S.C. §§ 7401 et seq.), the Clean Air Act, as amended (42 U.S.C. §§ 7401 et seq.), the Safe Drinking Water Act (42 U.S.C. §§ 300f et seq.), the Uranium Mill Tailings Radiation Control Act (42 U.S.C. §§ 7901 et seq.), the Federal Insecticide, Fungicide and Rodenticide Act (7 U.S.C. §§ 136 et seq.), all as now or hereafter amended or supplemented, and any regulations promulgated thereunder, and any other similar federal, state, or local statutes, rules and regulations.

"Environmental Liability" has the meaning set forth in Section 10.3.1.

"Facility" means the Mitchell Power Generation Facility consisting of two (2) coal-fired generating units, each having a nominal nameplate capacity of 800 megawatts, and associated plant, equipment and real estate, located in Moundsville, West Virginia, and includes all electrical or thermal devices, and related structures and connections that are located at the Site and used for the production of power and the transportation and handling of fuel for the benefit of the Owners, but excluding the real property and operation known as the Conner Run Fly Ash Impoundment and Dam.

"Facility Agreements" means this Agreement, the Ownership Agreement, all applicable interconnection agreements, fuel supply agreements, coal ash, gypsum and other combustion byproduct disposal or sales agreements, all applicable equipment maintenance agreements in effect or entered into, and as amended, supplemented or modified, from time to time by the Operator or the Owners relating to the Facility, all equipment contracts with regard to warranties and equipment design and specifications, and any other agreement reasonably designated by the Owners as a "Facility Agreement."

"Facility Equipment" has the meaning set forth in Section 13.1.

"Facility Personnel" means those individuals who are employed by Operator or its Affiliates to perform services in respect of the Facility under this Agreement.

"Force Majeure Event" has the meaning set forth in Section 14.6.1.

"Governmental Approval" means any consent, license, approval, exemption, Permit, "no objection certificate" or other authorization of whatever nature that is required to be granted by any Governmental Authority or any third party with respect to the siting, construction, operation, service and maintenance of the Facility in accordance with this Agreement, or otherwise necessary to enable an Owner or Operator to exercise its rights, or observe or perform its obligations, under this Agreement.

"Governmental Authority" means any federal, national, regional, state, municipal or local government authority, tribunal, court, agency, body, board or instrumentality, or any regulatory, administrative or other department, bureau or agency, or any political or other subdivision, department or branch of the foregoing, including any independent system operator, regional transmission organization or electric reliability organization.

"Hazardous Materials" means (a) any petroleum or petroleum products, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation, 1.4 Dioxane, per-and polyfluoroalkyl substances, and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls; (b) any chemicals, materials or substances that are now or hereafter become defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollution," "pollutants," "regulated substances," or words of similar import under Applicable Law; or (c) any other chemical, material, substance or waste declared to be or regulated as hazardous, toxic or polluting material by any Governmental Authority, exposure to which is now or hereafter prohibited, limited or regulated by any Governmental Authority.

"Late Payment Rate" means a rate of interest per annum equal to the lesser of (i) the "prime" rate of interest per annum for corporate loans as published in The Wall Street Journal under "Money Rates" as such rate may be in effect from time to time during the period the delinquent amount remains outstanding plus four (4) percentage points (4%) per annum or (ii) the maximum rate of interest permitted by Applicable Law.

"Lender" means any entity or entities providing financing or refinancing to an Owner under any financing agreements in connection with the construction or permanent financing for the Facility, and their permitted successors and assigns.

"Liabilities" means, collectively, any and all Claims, damages, judgments, losses, obligations, liabilities, actions and causes of action, fees (including reasonable attorneys' fees and disbursements), costs (including court costs), expenses, penalties, fines and sanctions.

"Manuals" means Facility Equipment manuals, system descriptions, system operating instructions, equipment maintenance instructions and pertinent design documentation created by the Persons that constructed the Facility or manufactured its equipment, and the operation and maintenance procedures and Facility systems descriptions, training, safety, chemistry and environmental manuals, together with the documents and schedules described in such manuals.

"NERC" means the North American Electric Reliability Corporation.

"Non-Operator Owner" has the meaning set forth in the preamble to this Agreement.

"Non-Operator Owner Indemnitees" has the meaning set forth in Section 10.1.

"Operating Committee" means the "Operating Committee" as composed from time to time pursuant to and defined in the Ownership Agreement.

"Operating Costs" has the meaning set forth in Section 7.2.1.

"Operator" has the meaning set forth in the preamble to this Agreement.

"Operator Indemnitees" has the meaning set forth in Section 10.2.

"Operator Proprietary Information" has the meaning set forth in Section 13.3.

"Owner" has the meaning set forth in the preamble to this Agreement.

"Ownership Agreement" has the meaning set forth in the recitals to this Agreement.

"Ownership Interest" has the meaning set forth in the Ownership Agreement.

"Party" means a party to this Agreement and "Parties" means, collectively, the parties to this Agreement, unless the context clearly requires a different construction.

"Permit" means any permit, license, consent, approval or certificate that is required or used for the operation or maintenance of the Facility or the performance of any Service and includes Permits required under Environmental Laws.

"Person" means any Party, individual, partnership, corporation, association, limited liability company, business trust, government or political subdivision thereof, governmental agency or other entity.

"Plan" means an annual operating plan adopted or amended pursuant to Section 5.3.

"Plant Manager" means the production/plant manager for the Facility selected in accordance with Section 3.6, Section 8.5 or Section 8.6.

"Project Manager" means the individual appointed in accordance with Section 5.1.

"Prudent Operation and Maintenance Practices" means those practices, methods and acts generally employed in the power generation industry with respect to facilities of similar type, fuel characteristics and geographical location as the Facility, that at the particular time in question, in the exercise of reasonable judgment in light of the facts known at the time the decision in question was being made, would have been expected to accomplish the desired result of such decision consistent with the goals established in a Budget and Plan, and the requirements of Applicable Law, System Operators, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy and expedition. With respect to Operator, Prudent Operation and Maintenance Practices are not limited to the optimum practices, methods or acts to the exclusion of all others, but rather include a spectrum of possible practices, methods or acts commonly employed in the coal-fired power generation industry, including taking reasonable actions to provide a sufficient number of Persons who are available and adequately trained to provide Services at the Facility, and timely perform preventive, routine, and non-routine maintenance and repairs, as exemplified and generally described in Appendix A, subject, in all cases, to the Operator's duties and the limitations on Operator's authority, as set forth in this Agreement and the Ownership Agreement.

"Qualified Replacement Operator" shall mean a Person that:

(i) has operated for a period of at least three (3) years, and continues to operate, coal and/or natural gas power generation facilities with an aggregate electricity output of at least one thousand (1,000) megawatts and at least one of those facilities is a coal power generation facility with an aggregate electricity output of at least three hundred (300) megawatts (or has engaged a third party to operate the Facility who satisfies such operation standards); and

(ii) either has (a) a credit rating of "BBB-" or higher by S&P Global Ratings and "Baa3" or higher by Moody's Investor Service or (b) a tangible net worth of at least $500,000,000 (or has a direct or indirect parent who satisfies such financial standards).

"Services" has the meaning set forth in Section 3.1.

"Site" means the land on which the Facility is situated.

"Standards of Performance" means the standards for Operator's performance of the Services set forth in Section 3.3.

"System Operator" means any Person or regional transmission organization, such as PJM Interconnection, L.L.C., supervising the collective transmission or generation facilities of the power region in which the Facility is located that is charged with coordination of market transactions, system-wide transmission planning and network reliability.

"Term" means the initial term together with any extensions.

"Termination Transition Period" has the meaning set forth in Section 8.5.1.

"WPCo" has the meaning set forth in the preamble to this Agreement.

"Year" means the calendar year. With respect to the Year in which the Effective Date occurs, a Year will be deemed to begin on the Effective Date and end on December 31st of such Year. If this Agreement terminates, the final Year will be deemed to end on the date that termination occurs.

## ARTICLE III - RESPONSIBILITIES OF OPERATOR

3.1 Provision of Services. Operator shall operate and maintain the Facility and perform other duties as set forth in this Agreement and as directed by the Owners pursuant to the Ownership Agreement, including performing and, as applicable, contracting for the benefit of the Owners with suppliers and service providers to perform, the services set forth on Appendix A (collectively, the "Services") and agrees to be responsible for the day-to-day operation and maintenance of the Facility.

3.2 Procurement.

3.2.1 Operator shall sign contracts and purchase orders for goods and services to be delivered to the Facility in the name of Operator as agent for the Owners, and shall not contract in the name of the Non-Operator Owner without the Non-Operator Owner's prior written consent. Operator acknowledges that such contracts and purchase orders are for the benefit of the Owners and the Facility. Operator shall endeavor to negotiate with vendors from standard terms and conditions, including reasonable warranties for the benefit of the Owners.

3.2.2 The Non-Operator Owner shall use commercially reasonable efforts to obtain, promptly following the Effective Date, any and all consents of third parties required to assign, transfer or convey to Operator any contracts or purchase orders for goods and services (including fuel supply and transportation) to be delivered to or used by the Facility that are in the name of the Non-Operator Owner as a result of the Non-Operator Owner having served as the Operator prior to the Effective Date, which are reasonably required to be transferred to Operator for the performance of the Services. To the extent that, notwithstanding its commercially reasonable efforts, the Non-Operator Owner is unable to obtain any such required consent effective as of the Effective Date, and as a result thereof Operator shall be prevented by such third party from receiving the rights and benefits with respect to any such contract or purchase order intended to be transferred hereunder, or if any attempted assignment would adversely affect the rights of the Non-Operator Owner thereunder so that Operator would not in fact receive all such rights or the Non-Operator Owner would forfeit or otherwise lose the benefit of rights that the Non-Operator Owner is entitled to retain, the Non-Operator Owner and Operator shall cooperate to implement any lawful and commercially reasonable arrangement as the Non-Operator Owner and Operator shall agree, under which Operator would, to the extent practicable, obtain the claims, rights and benefits under such contract or purchase order and assume the burdens and obligations with respect thereto, including by the Non-Operator Owner subcontracting, sublicensing, subleasing, delegating or granting a limited power of attorney or similar appointment as agent to Operator to administer such contracts or purchase orders; provided, however, that the Non-Operator Owner and WPCo shall each bear its respective share of the costs and expenses under any such contract or purchase order in accordance with this Agreement and the Ownership Agreement. The Non-Operator Owner and Operator shall continue to cooperate to assign, transfer or convey to Operator any such contract or purchase order that remain held by the Non-Operator Owner and to otherwise arrange for Operator to directly contract with the applicable third party for any renewal contract or purchase upon the expiration or termination of any such contract or purchase order.

3.3 Standards for Performance of the Services. Operator shall perform the Services in accordance with (i) the Manuals, (ii) the applicable Budget and Plan, (iii) Applicable Laws, (iv) Prudent Operation and Maintenance Practices, (v) insurer requirements delivered to Operator by the Owners in writing, (vi) the requirements in the Facility Agreements (vii) this Agreement; and (viii) as directed by the Owners pursuant to the Ownership Agreement. Subject to the other provisions of this Agreement, Operator shall perform the Services and other obligations under this Agreement in a manner consistent with the Operating Committee's directions. The Parties acknowledge and agree that, subject to Operator's compliance with the Standards of Performance, Operator shall have no liability for acting or refraining to act in accordance with the directions of the Operating Committee, except to the extent caused by Operator's gross negligence, willful misconduct, fraud, willful violation of any Applicable Law, willful breach of this Agreement or the Ownership Agreement or other willful misconduct.

3.4 Dispatch. Operator shall use commercially reasonable efforts to comply with any applicable dispatch instructions of the System Operator and, to the extent applicable, the directions of the Operating Committee or other Person identified by an Owner in writing to Operator as being authorized to provide dispatch instructions made in accordance with the Ownership Agreement. Operator shall give the Operating Committee notice as soon as practicable of any inability of the Facility to make the requisite deliveries of energy, capacity or ancillary services and of Operator's plan to restore operation of the Facility. In the case of any interruption, curtailment or reduction in (i) supplies of fuel or (ii) acceptance of energy, capacity or ancillary services by the System Operator or in the case of any other dispatch constraint imposed on the Facility, Operator shall notify the Non-Operator Owner as soon as practicable. Upon removal of the constraint, Operator shall use its commercially reasonable efforts to restore the availability of the Facility for dispatch consistent with applicable dispatch instructions of the System Operator and, to the extent applicable, the directions of the Operating Committee or other Person identified by an Owner in writing to Operator as being authorized to provide dispatch instructions made in accordance with the Ownership Agreement.

3.5 Licenses and Permits.

3.5.1 General. Operator shall review all Applicable Laws containing or establishing compliance requirements in connection with the operation and maintenance and Decommissioning of the Facility and shall use commercially reasonable efforts to obtain and maintain, for the benefit of both Owners, all Permits required by Applicable Law for the ownership, operation, maintenance and Decommissioning of the Facility and for Operator's performance of the Services, and shall (i) from time to time, notify the Operating Committee if Operator believes that a Permit is required by Applicable Law to be obtained by an Owner in its name in order to allow Operator to perform the Services and assist each Owner, at each Owner's written request and such Owner's sole cost and expense, in securing and complying with, as appropriate, all necessary Permits (and renewals of the same) which are required to be in an Owner's name, including those relating to air emissions, boiler operation, water usage, septic system operation, wastewater discharge, chemical and other waste (including Hazardous Materials) storage and disposal, emissions testing and safety, and (ii) initiate and maintain precautions and procedures reasonably necessary to comply with Applicable Laws. Any Permit held solely in the name of Operator shall, to the extent necessary for the other Owner's compliance with Applicable Law in its role as an Owner, be held by Operator for the benefit of both Owners. Any Permit held solely in the name of the Non-Operator Owner shall, to the extent necessary and consistent with Applicable Laws, be made available for the use of the Operator for the benefit of the Owners and, if reasonably necessary to facilitate Operator's operation and maintenance or Decommissioning of the Facility, the Non-Operator Owner shall cooperate with Operator to effect an assignment or other transfer of such Permit to Operator or otherwise submit such Permit modifications or updating information as necessary to reflect the role of Operator with respect to such Permit.

3.5.2 NERC Compliance. Operator (or an Affiliate thereof) shall register with NERC as the "Generator Owner" and "Generator Operator" for the Facility in accordance with 18 C.F.R. § 39.2(c) effective from and after [the Effective Date][1]. On and after [the Effective Date], Operator shall, or shall cause its applicable Affiliate to, (i) maintain compliance with all NERC reliability standards applicable to the Facility and all NERC rules applicable to Operator as Generator Owner and Generator Operator for the Facility in accordance with 18 C.F.R. § 39.2(b), including any actions related to mitigation and compliance enhancement required or implemented thereunder; (ii) provide notice to the Operating Committee promptly following the determination by Operator of any reportable physical or cyber security incident under the NERC reliability standards or other Applicable Law; (iii) maintain and provide documentation and maintenance records to the Operating Committee regarding any operation, testing, maintenance or faults of any

[1] **Note**: Subject to modification if registration cannot be effective as of the Effective Date.

generation protection relays, gen-tie relays or any other equipment necessary to fulfill Operator's or its applicable Affiliate's obligations as the Generator Owner or Generator Operator for the Facility; and (iv) provide to the Non-Operator Owner upon written request any other information, documentation and support reasonably necessary for Operator or its applicable Affiliate to demonstrate compliance with the NERC reliability standards. To the extent that any fine or sanction is imposed in respect of the performance of Operator's obligations under this Section 3.5.2 pursuant to Section 215(c) of the Federal Power Act, any cost related thereto shall be a included as an Operating Cost, to the extent permitted by Applicable Law.

3.6 Personnel Matters. Subject to Sections 8.5 and 8.6, and as otherwise set forth in this Section 3.6, Operator shall be responsible for determining the working hours, rates of compensation and all other matters relating to the employment of Operator's Facility Personnel, including the designation or appointment of the Plant Manager, in its reasonable judgment and in accordance with Non-Operator Owner's and its Affiliates' past practices in the ordinary course of its business during the time it served as operator of the Facility, and shall retain sole authority, control and responsibility with respect to its employment policies. Operator shall submit for the Operating Committee's approval the staffing requirements for the Facility on an annual basis. If Operator intends to select a new Plant Manager, or if the individual serving as Plant Manager ceases to be the Plant Manager, Operator shall provide prompt written notice to the Non-Operator Owner of the selection of a substitute Plant Manager. Facility Personnel shall be qualified and experienced in the duties to which they are assigned. Operator shall, upon the reasonable written request of the Non-Operator Owner, for cause (as documented in reasonable detail in any such written request), use commercially reasonable efforts to, as promptly as practicable under the circumstances and subject to any applicable collective bargaining agreements, remove from the Site and the Facility workforce, the services of any employee or other individual, subject to Operator's confirmation that such cause exists.

3.7 No Liens or Encumbrances. Operator shall use commercially reasonable efforts to keep and maintain the Facility free and clear of all liens and Encumbrances resulting from the failure by Operator to perform the Services or the personal debts and obligations of Operator unrelated to its ownership interest in the Facility.

3.8 Emergency Action. In the event of an emergency affecting the safety, health or protection of, or otherwise endangering, any Person, property or the environment located at or about the Facility (an "Emergency"), Operator shall take prompt action in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate any imminent damage, injury or loss threatened by such Emergency, and shall notify the Non-Operator Owner of such Emergency and Operator's response as soon as practical under the circumstances and in no event later than forty-eight (48) business hours after Operator becomes aware of such event. To the extent Operator procures goods and services as necessary to respond to an Emergency, reasonable and documented out of pocket costs in respect thereof shall be treated as Operating Costs.

## ARTICLE IV - OBLIGATIONS, RIGHTS AND REPRESENTATIVES OF EACH OWNER

4.1 General. Each Owner expressly reserves the exclusive authority to make, and shall make, such business and strategic decisions as it deems appropriate from time to time in reference to the operation and maintenance of the Facility in accordance with the Ownership Agreement. Upon request from Operator, the Non-Operator Owner shall promptly furnish or cause to be furnished to Operator, at the Non-Operator Owner's expense, the information, access, materials, instructions and other items described in this Article IV that are in the possession or control of the Non-Operator Owner and which are reasonably necessary for performance of the Services by Operator and not otherwise available to Operator. All such items will be made available at such times and in such manner as may be reasonably required for the expeditious and orderly performance of the Services by Operator.

4.2 Information. Subject to the Standards of Performance, Operator shall be entitled to rely upon any information provided by the Non-Operator Owner or any other party to the Facility Agreements in the performance of the Services.

4.3 Access to Facility. Each Owner shall provide Operator and Operator's contractors, vendors, suppliers, employees and agents and Facility Agreement counterparties, to the extent applicable, reasonable access to and use of the Facility and the Site and to such Owner's records and data at the Facility and, in the case of the Non-Operator Owner, reasonably available to the Non-Operator Owner or in the Non-Operator Owner's possession and reasonably necessary for the performance of Services by Operator under this Agreement.

4.4 Instructions, Approvals, etc. Each Owner shall provide or cause to be provided (including through action of the Operating Committee) to Operator all instructions Operator is required to obtain in accordance with this Agreement. Without limiting the provisions of Section 3.2.2, each Owner shall reasonably cooperate to make available or cause to be available to Operator the benefits of all assets (including Permits and contracts relating to the Facility) held in the name of such Owner, as reasonably required for the operation of the Facility. Each Owner shall not direct Operator to take any action inconsistent with Applicable Law or otherwise adversely affecting the safety, health or protection of any person, or property or the environment located at or about the Facility.

## ARTICLE V - REPRESENTATIVES, BUDGETS AND REPORTS

5.1 Representatives of Operator. On or as soon as practical after the Effective Date, Operator shall appoint a Project Manager who shall be authorized to represent Operator with each Owner and the Operating Committee concerning Operator's performance of the Services. The Project Manager may be the same individual as the Plant Manager. Operator shall be responsible for all communications, directions, requests and decisions made by its Project Manager at its direction. Operator shall notify the Non-Operator Owner in writing upon the appointment of its Project Manager, and of any successors. The Project Manager has no authority to modify, amend or terminate this Agreement or, absent written notice by Operator to the contrary, to enter into any other agreement on behalf of Operator other than as provided herein.

5.2 Representatives of Owner; Operating Committee. The Operating Representative of each Owner (pursuant to and as defined in the Ownership Agreement) shall be authorized and empowered to act for and on behalf of such Owner on all matters requiring the consent, approval or other action of an Owner pursuant to this Agreement. Each Owner shall notify Operator and the other Operating Representative in writing upon the appointment of its Operating

Representative, and of any successors. Any provision of this Agreement requiring the consent, approval, or similar act of the Operating Committee shall mean the consent, approval, or similar act of the Operating Committee acting in accordance with the terms of the Ownership Agreement.

5.3 Plans and Budgets.

5.3.1 Adoption.

5.3.1.1. Budgets. The initial Budget and Plan for the first Year following the Effective Date is attached as Appendix B hereto. No later than ninety (90) days prior to each operating Year, Operator shall deliver to the Operating Committee for the Operating Committee's review, revision if applicable and approval (i) a proposed annual operating budget, (ii) any proposed amendments to the annual capital budget, (iii) an annual operating plan and (iv) a six (6) Year future forecast of operating and capital expenses. Each such proposed budget, plan and forecast shall contain such detail and supporting documentation as reasonably necessary or reasonably requested for the Operating Committee's review, and Operator shall provide all such additional information and supporting documentation as may be reasonably requested by the Operating Committee and as required by the Ownership Agreement. The Operating Committee shall review and provide modifications to each such proposed budget, plan and forecast and Operator shall cooperate to revise each such proposed budget and plan to receive the Operating Committee's approval of same by December 1 of each Year. Each Budget and Plan as approved by the Operating Committee or otherwise deemed implemented pursuant to the Ownership Agreement shall remain in effect in accordance with the Ownership Agreement. Operator and the Non-Operator Owner by mutual agreement may modify the process and procedures set forth in this Section 5.3.1.

5.3.1.2. Amendments. If either the Non-Operator Owner or Operator becomes aware of facts or circumstances that it believes necessitate a change to a Budget or Plan, that Party shall promptly notify the other Party in writing, specifying the impact upon the Budget and the reasons for the change. The Project Manager shall then discuss appropriate amendments to the Budget with the Operating Committee.

5.3.1.3. Failure to Agree. Operator acknowledges that the Owners retain ultimate authority with respect to expenses incurred for the Facility. Accordingly, Operator shall accept each Budget as determined in accordance with the Ownership Agreement. To the extent that the Operating Committee limits funds for Operating Costs, Operator shall be relieved from performing only those specific Services that would result in the incurrence of such non-reimbursable Operating Costs.

5.3.2 Limitations on Variation from Budget. Except as otherwise permitted in response to an Emergency in accordance with Section 3.8, Operator shall obtain the Operating Committee's written approval (i) for any expenditures resulting in cumulative budget overruns exceeding ten percent (10%) in the aggregate in any Year with respect to either the operating Budget or capital expense Budget, or (ii) for any unbudgeted expenditure or capital project having a projected cost of more than $100,000.

5.4 Availability of Operating Data and Records. Operator shall deliver Facility data recorded, prepared or maintained by Operator to the Operating Committee: (i) as necessary or reasonably requested by an Owner to assist each Owner in complying with requirements of Governmental Authorities, Permits and Facility Agreements; or (ii) upon request by the Non-Operator Owner, in each case as soon as reasonably practicable but in any event within ten (10) Business Days following such request.

5.5 Litigation and Permit Lapses. Promptly upon obtaining actual knowledge thereof, either Party shall submit prompt written notice to the other Party of the following, to the extent relating to the Facility or the Services or agreements relating to either the Facility or the Services: (i) any litigation, Claims or actions filed, including by, against or with any Governmental Authority; (ii) any actual refusal to grant, renew or extend, or any action filed with respect to the granting, renewal or extension of, any Permit; (iii) all penalties or notices of violation issued or asserted by any Governmental Authority; (iv) any dispute with any Governmental Authority that may affect the Facility in any material respect; and (v) with respect to the matters identified in items (i), (ii), (iii) or (iv), any material threats of such matters. Upon Non-Operator Owner's request, Operator shall provide any documentation related to any of the foregoing.

5.6 Other Information. Operator shall promptly submit to the Non-Operator Owner any material information concerning new or significant aspects of the Facility operations and, upon the Non-Operator Owner's request, shall promptly submit any other information concerning the Facility or the Services.

5.7 Records Maintenance and Retention. Operator shall maintain all records, reports, documents and data, including all data retrievable from an electronic data storage source, for the Facility in accordance with Applicable Law and shall retain and preserve all such records, reports, documents and data created in connection with the operation and maintenance of the Facility, in accordance with Applicable Law, provided that Operator shall notify the Non-Operator Owner in writing at least sixty (60) days prior to the destruction or other disposition of any record, report, document or data. If the Non-Operator Owner gives written notice to Operator prior to the expiration of the 60-day period, Operator shall maintain custody of such material until the earlier of (i) such time as the Non-Operator Owner notifies Operator to dispose of such material and (ii) seven (7) Years. If the Non-Operator Owner does not provide written notice to Operator prior to the expiration of the 60- day period, Operator may destroy or dispose of such material and shall provide the Non-Operator Owner with a certificate confirming such destruction or disposition.

## ARTICLE VI - LIMITATIONS ON AUTHORITY

6.1 Limitations on Authority. Operator has no authority to make policies or decisions with respect to the overall operation or maintenance of the Facility as a commercial enterprise pursuant to the terms of this Agreement. The Owners, acting through the Operating Committee and pursuant to the terms of the Ownership Agreement, shall determine all such matters. Notwithstanding any provision in this Agreement to the contrary, unless previously approved in a Budget and Plan or otherwise approved in writing by the Operating Committee, in connection with Operator's provision of Services hereunder, Operator is prohibited from doing any of the following (and shall not permit any of its agents, Affiliates, or representatives to do any of the following):

6.1.1 Dispose of Assets. Selling, leasing, pledging, mortgaging, granting a security interest in, encumbering, conveying, or making any license, exchange or other transfer or disposition of all or any portion of the Facility, the Site or any other property or assets of the Owners, including any property or assets purchased by Operator, the cost of which is an Operating Cost;

6.1.2 Make Expenditures. Making any expenditure or acquiring, on an Operating Cost basis, any goods or services from third parties, except in conformity with a Budget or as otherwise permitted under Section 5.3.2 or as authorized by the Operating Committee; provided, however, that in the event of an Emergency, Operator, without approval from the Owners, is authorized to take all reasonable actions in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate such threatened damage, injury or loss in accordance with Section 3.8;

6.1.3 Take Other Actions. Taking or agreeing to take any other action or actions the decision for which is reserved exclusively for the Operating Committee pursuant to the Ownership Agreement; provided, however, that in the event of an Emergency, Operator, without approval from the Operating Committee, is authorized to take all reasonable actions in accordance with Prudent Operation and Maintenance Practices to prevent or mitigate such threatened damage, injury or loss in accordance with Section 3.8;

6.1.4 Act Regarding Lawsuits and Settlements. Settling, compromising, assigning, pledging, transferring, releasing or consenting to the compromise, assignment, pledge, transfer or release of, any material Claim, suit, debt, demand or judgment against or due by any Owner or Operator, the cost of which would be an Operating Cost hereunder, or submitting any such Claim, dispute or controversy to arbitration or judicial process, or stipulating in respect thereof to a judgment, or consent to the same; provided, however, that such prohibition shall not apply to, nor shall it be construed as a release or waiver of, any of Operator's rights or obligations pursuant to this Agreement or any other agreement between the Parties; or

6.1.5 Pursue Transactions. Engaging in any other transaction on behalf of the any Owner that is not permitted under this Agreement.

## ARTICLE VII - COMPENSATION AND PAYMENT

7.1 General. The Non-Operator Owner shall pay Operator, and WPCo shall bear directly in its capacity as an Owner, its allocated share in accordance with the Ownership Agreement of all Operating Costs, all as further described below. All Operating Costs shall initially be paid for by Operator (except as otherwise provided in this Agreement) and subsequently invoiced monthly in arrears as more fully set forth in this Article VII.

7.2 Costs.

7.2.1 Operating Costs. Subject to the Ownership Agreement and the limitations on expenditures set forth elsewhere in this Agreement (including Section 5.3), the Non-Operator Owner shall reimburse Operator for its allocated share in accordance with the Ownership Agreement of the fully distributed costs incurred (whether paid or accrued) in the provision of

Services (which shall be allocated consistent with Non-Operator Owner's and its Affiliates past practices in the ordinary course of business during the time it served as operator of the Facility and in any event in accordance with the Cost Allocation Manual with respect to costs incurred by Affiliates of Operator), including for labor, goods, services, capital expenditures, overhead, cost of capital, Taxes (other than income or franchise taxes), Permits and bonds (the "Operating Costs"), in each case invoiced in a manner consistent with the example invoice worksheets attached hereto as Appendix C, which shall include such costs with respect to: (i) equipment, material, supplies and other consumables, spare parts, replacement components, tools, office equipment, computer equipment, software, information technology and supplies acquired for use at the Facility; (ii) fuel supply and transportation; (iii) costs associated with special training of Facility Personnel and associated travel and living expenses; (iv) amounts paid under subcontracts, purchase orders and agreements; (v) fees for Permits required to be held by Operator; (vi) community relations and labor relations activities; and (vii) Operator's cost of Facility Personnel (and the allocable portion of other employees of Operator and its Affiliates attributable to performing the Services) wages, salaries, overtime, employee bonus, customary or required severance payments, unemployment insurance, long-term disability insurance, short term disability payments, sick leave, payroll taxes imposed on wages and benefits, worker's compensation costs and holidays, vacations, group medical, dental and life insurance, defined contribution retirement plans and other employee benefits; (viii) costs of third-party advisors, consultants, attorneys, accountants and contractors retained and managed by Operator in support of, and allocable to, the Services; (ix) a reasonably allocable portion of the cost of the insurance maintained by Operator in accordance with Section 9.1 on account of its Operator role; (x) reasonable costs incurred in response to an Emergency; and (xi) any other activity that Operator is required or expressly requested in writing by the Owners to perform under this Agreement for the benefit of the Facility or that is approved in a Budget or by the Operating Committee pursuant to the terms of this Agreement.

7.2.2 Invoicing. On or before the twenty-fifth ($25^{th}$) day of each calendar month during the Term, Operator shall submit invoices to the Non-Operator Owner in form and substance reasonably similar to that attached hereto as Appendix C for Operating Costs incurred during the preceding calendar month (as well as any such costs for any prior period that were not previously invoiced). If any contract or purchase order intended to be assigned, transferred or conveyed to Operator remains held by the Non-Operator Owner as described in Section 3.2.2 and the Non-Operator Owner directly pays costs thereunder for the benefit of the Owners, the invoice submitted by Operator shall net WPCo's allocated share in accordance with the Ownership Agreement of any such costs paid by the Non-Operator Owner for the benefit of the Owners. The Non-Operator Owner shall make payment to Operator of its allocated share in accordance with the Ownership Agreement of the invoiced amount no later than the Due Date. For the avoidance of doubt, WPCo, in its capacity as an Owner, shall bear directly its allocated share in accordance with the Ownership Agreement of such Operating Costs.

7.3 Cost Audit. The Non-Operator Owner shall be entitled to conduct an audit, or to delegate a representative to audit, at its sole cost and expense and review of Operator's books and records with respect to all Operating Costs and performance of the Services together with any supporting documentation for a period of one (1) Year from and after the date of the audited payment. If, pursuant to such audit and review, it is agreed that any amount previously paid by

Operator or by an Owner was not properly incurred as an Operating Cost or an adjustment of any such cost is required, Operator shall credit to the Non-Operator Owner or Operator, as applicable, its allocated share in accordance with the Ownership Agreement of such amount in the next succeeding invoice or promptly paid in cash if there shall not be further invoices issued.

7.4 Late Payment Rate. To the extent a Party fails to pay any amount required to be paid under this Agreement by the Due Date, the unpaid amount shall accrue interest each day at the Late Payment Rate from the Due Date until such amount (plus accrued interest) is paid by the applicable Party in full. In the event any paid amounts are disputed by a Party in good faith and such dispute is resolved (including if applicable in accordance with the procedures set forth in Section 14.7) in the favor of such Party, then the applicable other Party shall repay to such Party such overpaid amount plus interest thereon accrued each day at the Late Payment Rate from payment by such Party until such amount (plus accrued interest) is repaid in full to such Party by the applicable other Party.

## ARTICLE VIII - TERM

8.1 Term. The Term of this Agreement shall commence on the Effective Date and, subject to approval or acceptance of termination by FERC or other Governmental Authority to the extent required, shall end on the date of termination of the Ownership Agreement (the "Term"). Notwithstanding the foregoing, this Agreement and the Term is subject to earlier termination pursuant to Sections 8.2 and 8.3.

8.2 Termination by the Non-Operator Owner for Cause. The Non-Operator Owner shall be permitted to terminate this Agreement upon written notice to Operator if any of the following events occur: (i) the Bankruptcy of Operator; (ii) a payment default by Operator (other than a disputed payment) that Operator fails to cure within ten (10) Business Days after Operator has received written notice of such default; (iii) Operator incurs liability to the Owners equal to the liability limit set forth in Section 11.2 for any two Years during the Term (provided that written notice of termination must be delivered to Operator no later than ninety (90) days after the end of the second of such two Years), or (iv) a material default by Operator in the performance of its obligations under this Agreement, including any default that has, or is reasonably expected to have, a material adverse effect on the operations, maintenance or performance of the Facility and Operator has failed to cure such default within sixty (60) days of written notice of such failure; provided, that if it is not possible to cure such breach within sixty (60) days of receipt of such notice of failure, Operator (A) fails to commence to cure the breach within such sixty (60) day period, (B) thereafter fails to continue diligent efforts to complete the cure as soon as reasonably possible, or (C) fails to complete the cure within ninety (90) days of receipt of such notice of failure. In addition, Non-Operator Owner shall have the option to terminate this Agreement for convenience upon ninety (90) days written notice to Operator delivered no later than ninety (90) days after the occurrence of any transfer, assignment, sale or other disposition (including any transfers, assignments, sales or other dispositions in connection with a foreclosure or an exercise of remedies by the Financing Parties) that results in WPCo's Ownership Interest no longer being owned directly or indirectly by AEP or an Affiliate thereof, except in the case of an transfer, assignment, sale or other disposition to a successor Operator that is a Qualified Replacement Operator in compliance with the terms of this Agreement and the Ownership Agreement.

8.3 Termination by Operator. Operator shall be permitted to terminate this Agreement upon written notice to the Non-Operator Owner if any of the following events occur: (i) a payment default by the Non-Operator Owner (other than a disputed payment) that is not cured within thirty (30) days after the Due Date for any invoice; (ii) the Bankruptcy of the Non-Operator Owner; or (ii) a default by the Non-Operator Owner of any other obligation under this Agreement that has a material adverse effect on Operator's ability to perform the Services and that the Non-Operator Owner has failed to cure or make substantial progress in the reasonable opinion of Operator toward curing within ninety (90) days of written notice by Operator to the Non-Operator Owner of such failure. As soon as practicable after all cost information is gathered following termination, Operator shall invoice the Non-Operator Owner for its allocated share in accordance with the Ownership Agreement for Services rendered by Operator through the termination date, including all Operating Costs incurred through the date of termination but not paid.

8.4 Transfer of Facility Custody. Upon expiration or termination of this Agreement, Operator shall leave at the Facility all documents and records, tools, supplies, spare parts, safety equipment, Manuals, and any other items furnished on an Operating Cost basis, all of which shall remain the property of the Owners without additional charge. Operator shall execute all documents and take all other reasonable steps as may be reasonably requested by the Non-Operator Owner to assign to and vest in a replacement provider of Services all of its pro-rata rights, benefits, interests and title in connection with any subcontracts Operator executed in its own name for the benefit of the Facility and the Owners.

8.5 Services Upon Termination.

8.5.1 Upon notice of termination of this Agreement by either Operator or the Non-Operator Owner, unless the Non-Operator Owner is then in payment default such that Operator would have the right to terminate this Agreement pursuant to Section 8.3(i), the Non-Operator Owner shall have the right to specify a period of transition of no longer than nine (9) months (the "Termination Transition Period") during which Operator shall: (i) continue to provide Services at the Facility in accordance with this Agreement; (ii) cooperate with the Non-Operator Owner in planning and implementing a transition to any replacement provider of Services; (iii) use its commercially reasonable efforts to minimize disruption of Facility operations in connection with such transition activities; (iv) make all requisite regulatory filings as promptly upon commencement of the Termination Transition Period, subject to cooperation of the Parties; (v) transfer all Permits, licenses, registrations, approvals and contracts to the Non-Operator Owner or such replacement operator, in each case, as requested by the Non-Operator Owner; and (vi) take all actions incidental thereto and as reasonably requested by the Non-Operator Owner. The provisions of Article VII shall continue to apply during the Termination Transition Period. To facilitate employee transfer, Operator shall permit the replacement service provider and the Non-Operator Owner to interview such Facility Personnel for potential positions with such replacement operator in a manner and at times that do not interfere with Operator's responsibility to perform the Services. If Operator or one of its Affiliates continues to own a portion of the Facility, Operator shall, or shall cause its Affiliates to, reasonably cooperate to allow a successor operator to operate the Facility after the termination of this Agreement, including by granting access rights and executing other instruments as may be reasonably requested by the Non-Operator Owner and any replacement operator.

8.5.2 Any modifications to the ownership and operation of the Facility, including any termination of this Agreement, shall be subject to any required regulatory or administrative filings and approvals.

8.6 Plant Manager Replacement. Upon (i) commencement of the Termination Transition Period or (ii) the occurrence of any of the conditions described in Section 8.2, the Non-Operator Owner may designate a qualified individual with significant experience as a project manager or similar senior operating role in respect of the management and operation of large coal-fired generation facilities with similar operating characteristics as the Facility to replace the existing Plant Manager and who shall upon such appointment be the Plant Manager.

## ARTICLE IX - INSURANCE

9.1 Operator Insurance Requirements.

9.1.1 Commencing with the performance of the Services hereunder, and continuing until the termination of this Agreement, Operator (and any tier subcontractors) shall maintain or cause to be maintained occurrence form (if written on a claims -made policy form, be maintained with a retroactive date that is prior to this Agreement Effective Date for a period of at least three (3) Years following the last Year in which such policy provides coverage under the terms of this Agreement) insurance policies as follows: (i) Workers' Compensation in accordance with the statutory requirements of the state in which the Services are performed and Employer's Liability Insurance of not less than one million Dollars ($1,000,000) each accident/employee/disease; (ii) Commercial General Liability Insurance having a limit of at least one million Dollars ($1,000,000) per occurrence/two million Dollars ($2,000,000) in the aggregate for contractual liability, personal injury, bodily injury to or death of Persons, and/or loss of use or damage to property, including but not limited to products and completed operations liability (which shall continue for at least three (3) Years after completion), premises and operations liability and explosion, collapse, and underground hazard coverage; (iii) Commercial/Business Automobile Liability Insurance (including owned (if any), non-owned or hired autos) having a limit of at least one million Dollars ($1,000,000) each accident for bodily injury, death, property damage and contractual liability and no fellow employee exclusion; (iv) Umbrella/Excess Liability insurance with limits of at least twenty-four million Dollars ($24,000,000) per occurrence and follow form of the underlying Employer's Liability, Commercial General Liability and Auto Liability insurance, and provide at least the same scope of coverages thereunder; (v) coverage for sudden/accidental occurrences for bodily injury, property damage, environmental damage, cleanup costs and defense with a minimum of one million Dollars ($1,000,000) per occurrence; and (vi) "all-risk" or its equivalent property insurance providing coverage risks of physical damage to the Facility or Facility Equipment in an amount in accordance with Good Utility Practice.

9.1.2 Unless otherwise determined by the Operating Committee that the Operator should purchase capacity insurance on behalf of both Owners, Operator (including in its capacity as an Owner) and Non-Operator Owner may each procure individually, in proportion to their Ownership Interests, PJM Interconnection, L.L.C. capacity performance insurance on terms and conditions, and placed with insurance companies, reasonably acceptable to the Operator or such Owner, as applicable. Operator shall make such certifications relating to the operation, maintenance and condition of the Facility from time to time during the Term as may be reasonably necessary in connection with the procurement or maintenance of such insurance coverage by Operator and the Non-Operator Owner and any other insurance policies of either Owner that may relate to coverage pertaining to or affecting an Owner's Ownership Interest.

9.2 Form and Content. All insurance policies provided and maintained by Operator and each subcontractor shall: (i) except with respect to insurance policies issued by any "captive" insurer of Operator or its Affiliates, be underwritten by insurers that are rated A.M. Best "A- VII" or higher; (ii) specifically include the Non-Operator Owner and its directors, officers, employees, affiliates, subcontractors, and joint owners of any facilities as additional insureds for their liability arising out of the acts or omissions of Operator, including for completed operations, with respect to Operator's acts, omissions, services, products or operations, whether in whole or in part, excluding, however, for Workers' Compensation/Employer's Liability insurance, Pollution Legal Liability insurance, and "all-risk" property insurance; (iii) be endorsed to provide, where permitted by law, waiver of any rights of subrogation against an Owner and its directors, officers, employees, affiliates and subcontractors, and joint owners of any facilities; (iv) provide that such policies and additional insured provisions are primary with respect to the acts, omissions, services, products or operations of Operator or its subcontractors, to the extent of Operator's negligence, (v) contain standard separation of insured and severability of interest provisions except with respect to the limits of the insurer's liability; and (vii) not have any cross-liability exclusion, or any similar exclusion that excludes coverage for Claims brought by additional insureds under the policy against another insured under the policy; Any deductibles or retentions shall be the sole responsibility of Operator and its subcontractors. Evidence of such coverage shall be provided in the form of Operator's certificate of insurance furnished to the Non-Operator Owner prior to the Effective Date, upon any policy replacement or renewal and upon the Non-Operator Owner's request. Operator shall provide at least thirty (30) days' prior written notice to the Non-Operator Owner prior to cancellation of any policy (or ten (10) days' notice in the case of non-payment of premium).

## ARTICLE X - INDEMNIFICATION

10.1 Operator Indemnification. Subject to the limitations of liability in Section 11.1, Operator shall indemnify and hold harmless the Non-Operator Owner and its Affiliates, and their respective officers, directors, employees, managers, members, agents and representatives (collectively, the "Non-Operator Owner Indemnitees"), from and against, and no Non-Operator Owner Indemnitee shall be responsible for any and all Liabilities incurred, assessed, sustained or suffered by any Non-Operator Owner Indemnitee to the extent caused by Operator's gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law, or willful breach of this Agreement. Any Liabilities paid by Operator pursuant to its indemnity obligation under this Section 10.1 shall in no event be considered Operating Costs hereunder.

10.2 Owner Indemnification. Subject to the limitations of liability in Section 11.1, each Owner shall, severally with respect to its proportionate share in respect of its Ownership Interest and not jointly, indemnify and hold harmless Operator and its Affiliates, and their respective officers, directors, employees, agents and representatives (collectively, the "Operator Indemnitees"), from and against, and no Operator Indemnitee shall have responsibility for, any and all Liabilities to a third party incurred, assessed, sustained or suffered by or against any Operator Indemnitee arising from or relating to Operator's performance of the Services under this

Agreement, except to the extent caused by Operator's gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law, or willful breach of this Agreement; provided, however, that the Liabilities for which Non-Operator Owner is obligated to indemnify any Operator Indemnitees under this Section 10.2 shall not in any event include any Liabilities for which WPCo is obligated to indemnify Non-Operator Owner (and/or its Affiliates) in any agreement among the Owners (and/or their Affiliates) and AEP (and/or its Affiliates), including pertaining to the allocation of emission limitations associated with the Facility. For the avoidance of doubt, WPCo, in its capacity as an Owner of the Facility, shall bear directly its proportionate share of Liabilities under this Section 10.2 in respect of its Ownership Interest.

10.3 Environmental Indemnification.

10.3.1 Owner Indemnity for Environmental Liabilities. Subject to the limitations of liability in Section 11.1, and without in any way limiting the provisions of Section 10.3.2, each Owner shall, severally with respect to its proportionate share in respect of its Ownership Interest and not jointly, indemnify and hold harmless the Operator Indemnitees, from and against, and no Operator Indemnitees shall have responsibility for, any and all Liabilities, including all civil and criminal fines or penalties and other costs and expenses incurred, assessed, sustained or suffered by or against any Operator Indemnitees, as applicable, as a result of or in connection with any matters governed by Environmental Laws directly or indirectly related to or arising out of (i) the design, permitting or construction of the Facility or the condition of the Site, and any adjacent parcels; (ii) the operation, maintenance, ownership, control or use of the Facility or otherwise related to the Facility; and (iii) the offsite transportation, treatment or disposal of all wastes generated at the Facility and any properties included within or adjacent to the Site, whether occurring before or after the Effective Date (collectively, "Environmental Liabilities"), including any Environmental Liabilities arising out of the actual or alleged existence, generation, use, emission, collection, treatment, storage, transportation, disposal, recovery, removal, release, discharge or dispersal of Hazardous Materials, but excluding Operator Environmental Liabilities; provided, however, that the Environmental Liabilities for which any Owner is obligated to indemnify any Operator Indemnitees under this Section 10.3.1 shall not in any event include any Operator Environmental Liabilities for which Operator is liable under Section 10.3.2. For the avoidance of doubt, WPCo, in its capacity as an Owner of the Facility, shall bear its proportionate share of Environmental Liabilities under this Section 10.3.2 in respect of its Ownership Interest.

10.3.2 Operator Indemnity for Environmental Liabilities. Subject to the provisions of Section 10.1 and the limitations of liability in Section 11.1, Operator shall indemnify and hold harmless the Non-Operator Owner Indemnitees from and against, and no Non-Operator Owner Indemnitee shall be responsible hereunder for any Liabilities, including any civil and criminal fines or penalties and other costs and expenses incurred, assessed, sustained or suffered by or against any Person as a result of or in connection with any breach or violation of or any other matters governed by Environmental Laws to the extent caused by the gross negligence, willful misconduct, actual fraud, willful violation of any Applicable Law or willful breach of this Agreement by Operator or arising out of the existence, generation, use, emission, collection, treatment, storage, transportation, disposal, recovery, removal, release, discharge or dispersal of Hazardous Materials brought on Site by Operator or its Affiliates or agents on or after the Effective Date (the "Operator

Environmental Liabilities"). Operator understands and agrees that any Operator Environmental Liabilities paid by Operator pursuant to this Section 10.3.2 shall not be Operating Costs hereunder.

10.3.3 Governmental Actions. During the Term, Operator shall use commercially reasonable efforts to cooperate with and assist the Owners with their acquisition of data and information, and preparation and filing with appropriate Governmental Authorities of any notices, plans, submissions, or other materials and information necessary for compliance by the Owners with applicable Environmental Laws and the requirements of any Permits related to the Facility. All such environmental reports shall be submitted by, and in the names of, both Owners. All reasonable and documented costs associated therewith, including the reasonable costs of any outside consultants, legal services, Governmental Authority charges, sampling and remedial work shall be paid by the Owners as an Operating Cost, and the Non-Operator Owner shall reimburse WPCo to the extent of the Non-Operator Owner's pro rata share, unless such costs are incurred arising out of or associated with Operator Environmental Liabilities that are subject to Operator's indemnity obligation pursuant to Section 10.3.2 hereof. Nothing contained herein shall be construed as requiring Operator to take any corrective action with respect to Environmental Liabilities unless (x) affirmatively and expressly directed in writing to so do by the Operating Committee and appropriate funding is made available, or (y) affirmatively and expressly directed to do so by a Governmental Authority, in order to comply with any Environmental Law, in which case the cost of any corrective actions so undertaken shall be deemed an Environmental Liability subject to Section 10.3.1 hereof (if not otherwise reimbursed as an Operating Cost hereunder), unless such Environmental Liability arises out of or is associated with Operator Environmental Liabilities subject to Operator's indemnity obligation pursuant to Section 10.3.2 hereof.

## ARTICLE XI - LIABILITIES OF THE PARTIES

11.1 Limitations of Liability. Notwithstanding any provision in this Agreement that may be susceptible to contrary interpretation, neither the Parties nor any Non-Operator Owner Indemnitees or Operator Indemnitees shall be liable for consequential or indirect loss or damage, including loss of profit, cost of capital, loss of goodwill, increased Operating Costs, or any special or incidental damages; provided, however, that notwithstanding the foregoing, in no event will the foregoing limitations of liability be applied to limit the extent of the liability of either Party to the other for or with respect to any Claims of third parties or to the extent arising from gross negligence, actual fraud, willful violation of Applicable Law or willful breach of this Agreement. The Parties further agree that the waivers and disclaimers of liability, indemnities, releases from liability and limitations of liability expressed in this Agreement shall survive termination or expiration of this Agreement, and shall apply in all circumstances, whether in contract, equity, tort or otherwise, regardless of the fault, negligence (in whole or in part), strict liability, breach of contract or breach of warranty of the Party indemnified, released or whose liabilities are limited, and shall extend to the Non-Operator Owner Indemnitees and Operator Indemnitees.

11.2 Operator's Total Aggregate Liability. Except to the extent that a Non-Operator Owner Indemnitee suffers Liabilities that are caused by, result from or arise out of Operator's or its Affiliates' breach of Article XIII or its gross negligence, actual fraud, willful violation of Applicable Law or willful breach of this Agreement, or willful misconduct (including in connection with any Services), the total liability of Operator to the Non-Operating Owner for all Liabilities arising out of, connected with or resulting from any events occurring or claims made in connection with this Agreement, whether based in contract, warranty, tort, strict liability or otherwise, shall not exceed, in the aggregate, the sum of (i) an amount equal to twenty-five percent (25%) of the Operating Costs, but excluding Operating Costs relating to any services, goods, inventory and equipment provided hereunder by third parties other than Operator's Affiliates, incurred pursuant to this Agreement in the prior twelve (12) month period, *plus* (ii) the Non-Operating Owner's fifty percent (50%) share of any insurance proceeds actually received by the Operator or paid on the Operator's behalf with respect to the relevant loss or damages under the insurance policies procured by the Operator pursuant to Section 9.1.

11.3 No Warranties or Guarantees.

11.3.1 EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, NEITHER PARTY MAKES ANY WARRANTIES OR GUARANTEES TO THE OTHER, EITHER EXPRESS OR IMPLIED, WITH RESPECT TO THE SUBJECT MATTER OF THIS AGREEMENT, AND BOTH PARTIES DISCLAIM AND WAIVE ANY IMPLIED WARRANTIES OR WARRANTIES IMPOSED BY LAW, INCLUDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR ANY IMPLIED WARRANTY OF NON-INFRINGEMENT.

11.3.2 OPERATOR IS ACTING AS AGENT OR OTHERWISE AS A RESELLER WITH RESPECT TO ALL SERVICES, GOODS, INVENTORY AND EQUIPMENT PROVIDED HEREUNDER BY THIRD PARTIES OTHER THAN OPERATOR'S AFFILIATES, AND, AS SUCH, DOES NOT PROVIDE ANY WARRANTY FOR SUCH THIRD PARTY SERVICES, GOODS, INVENTORY OR EQUIPMENT PROVIDED HEREUNDER. ALL SUCH THIRD PARTY SERVICES, GOODS, INVENTORY AND EQUIPMENT ARE PROVIDED AS IS, WHERE IS, WITH ALL FAULTS AND WITHOUT WARRANTY OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OR ANY IMPLIED WARRANTY OF NON-INFRINGEMENT UNLESS CAUSED BY THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT, ACTUAL FRAUD, WILLFUL VIOLATION OF ANY APPLICABLE LAW OR WILLFUL BREACH OF THIS AGREEMENT BY OPERATOR OR ITS AFFILIATES. THE SOLE REMEDY IN CONNECTION WITH ANY DEFECTS IN OR FAILURES OF SUCH THIRD PARTY SERVICES, GOODS, INVENTORY OR EQUIPMENT (WHETHER A CLAIM FOR SUCH DEFECT ARISES UNDER CONTRACT, TORT, STRICT LIABILITY, STATUTE, OR ANY OTHER LEGAL OR EQUITABLE THEORY OR PRINCIPLE INCLUDING NEGLIGENCE) SHALL BE TO SEEK RECOURSE EXCLUSIVELY FROM THE COUNTERPARTIES TO THE THIRD PARTY CONTRACTS, UNLESS THE DEFECT OR FAILURE WAS CAUSED BY THE GROSS NEGLIGENCE, WILLFUL MISCONDUCT, ACTUAL FRAUD, WILLFUL VIOLATION OF ANY APPLICABLE LAW OR WILLFUL BREACH OF THIS AGREEMENT BY OPERATOR OR ITS AFFILIATES.

## ARTICLE XII - CONFIDENTIALITY

12.1 General. During the Term, and for the later of three (3) Years after the termination of this Agreement or five (5) Years after receipt of the applicable Confidential Information, each Party shall hold in confidence any Confidential Information supplied by or on behalf of the other

Party. Each receiving Party further agrees to require its contractors, vendors, suppliers and employees, agents or prospective purchasers to preserve the confidentiality of Confidential Information. The receiving Party may make necessary disclosures to third parties directly engaged in the operation, ownership or financing of the Facility if such third parties are under an obligation to receive and hold such Confidential Information in confidence.

12.2 Exceptions. The provisions of this Article XII do not apply to information within one or more of the following categories:

12.2.1 Public Domain. Information that was in the public domain prior to the receiving Party's receipt or that subsequently becomes part of the public domain by publication or otherwise, except by the receiving Party's or its Affiliate's wrongful act.

12.2.2 Prior Receipt. Information that the receiving Party can demonstrate was in its possession prior to receipt thereof from the disclosing Party so long as such possession did not result from a violation of a confidentiality obligation.

12.2.3 Third Party Delivery. Information received from a third party having no obligation of secrecy with respect thereto.

12.2.4 Permitted Disclosures. Information disclosed by an Owner to Lenders or prospective Lenders, equity investors or prospective equity investors, prospective purchasers, consultants, attorneys, accountants and other designated agents in each case on a confidential, need-to-know-basis.

12.2.5 Regulatory Filings. Information required to be disclosed by an Owner in connection with any required regulatory or administrative filings.

12.3 Required Disclosure. Notwithstanding the forgoing, any receiving Party required by law, rule, regulation, subpoena or order, or in the course of regulatory, administrative or judicial proceedings, to disclose Confidential Information that is otherwise required to be maintained in confidence pursuant to this Article XII, may make disclosure notwithstanding the provisions of this Article XII. Prior to doing so, the receiving Party, promptly upon learning of the requirement, shall notify the disclosing Party of the requirement and cooperate to the maximum extent practicable to minimize the disclosure of Confidential Information. Any receiving Party disclosing Confidential Information pursuant to this Section 12.3 shall use commercially reasonable efforts, at the disclosing Party's cost, to obtain proprietary or confidential treatment of Confidential Information by the third party to whom the information will be disclosed, and to the extent such remedies are available, shall use commercially reasonable efforts to seek protective orders limiting the dissemination and use of Confidential Information. Nothing in this Agreement is intended to prevent the disclosing Party from appearing in any proceedings and objecting to the disclosure.

## ARTICLE XIII - TITLE, DOCUMENTS AND DATA

13.1 Materials and Equipment. Operator shall use commercially reasonable efforts to cause title to all materials, equipment, supplies, consumables, spare parts and other items purchased or obtained by Operator on an Operating Cost basis ("Facility Equipment") to pass directly from the vendor or supplier to, and vest in, each Owner to the extent of such Owner's Ownership Interest. Operator shall have no title or other claim to such items other than in its capacity as an Owner of the Facility.

13.2 Documents. All Manuals, operational data, Facility drawings, Operator reports and records and other materials and documents (both paper and electronic) created by Operator, its Affiliates or their respective employees, representatives or contractors in connection with performance of the Services are the property of each Owner to the extent of its Ownership Interest in the Facility. All such materials and documents shall be available for review by the Non-Operator Owner at all reasonable times during development and promptly upon completion. All such materials and documents required to be submitted for the approval of the Operating Committee shall be prepared and processed in accordance with the requirements and specifications set forth herein. However, the Operating Committee's approval of materials and documents submitted by Operator shall not relieve Operator of its responsibility to perform it obligations under this Agreement.

13.3 Proprietary Information. Where materials or documents prepared or developed by Operator or its Affiliates, or their respective employees, representatives or contractors, contain proprietary or technical information, systems, techniques or know-how previously developed by them or acquired by them from third parties (the "Operator Proprietary Information"), the Non-Operator Owner shall have an irrevocable license to use such Operator Proprietary Information to the extent necessary for the operation or maintenance of the Facility at no additional cost to the Non-Operator Owner.

## ARTICLE XIV - MISCELLANEOUS PROVISIONS

14.1 Assignment. This Agreement shall not be assignable, in whole or in part, by a Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed, except that this Agreement may be (i) collaterally assigned by an Owner without such consent to a Lender in connection with such Lender's financing of such Owner's Ownership Interest and (ii) assigned by an Owner (in whole but not in part) without such consent to the transferee of its Ownership Interest, whether by merger, division, sale of equity interest, or otherwise, in each case, solely to the extent that such transfer of its Ownership Interest is in accordance with the Ownership Agreement. Any assignment pursuant to this Section 14.1 shall not relieve the assigning Party of any of its obligations under this Agreement that arose prior to the date of such assignment. This Agreement shall be binding upon and inure to the benefit of the successors and permitted assigns of the Parties.

14.2 Effect of Bankruptcy. The Parties intend that, in the event of a Bankruptcy, payments required under this Agreement shall be deemed to be administrative expenses as defined in 11 U.S.C. §503.

14.3 Access. The Non-Operator Owner and Lenders and their agents and representatives shall have access to the Facility, all Facility operations and any documents, materials and records and accounts relating to the Facility operations for purposes of inspection and review. Upon the request of the Non-Operator Owner and its agents and representatives, Operator shall provide such Persons with access to all data and logs Operator maintains regarding the Facility. During any inspection or review of the Facility, the Non-Operator Owner and Lenders and their agents and representatives shall comply with all of Operator's safety and security procedures, and shall conduct inspections and reviews in such a manner as to cause minimum interference with Operator's activities. Operator also shall cooperate with the Non-Operator Owner in allowing its agents and representatives access to the Facility.

14.4 Subcontractors; Subagents.

14.4.1 Operator shall have the right to hire third-party subcontractors or to acquire rights from third parties to provide all or part of any Services hereunder without the prior consent of the Operating Committee. The cost of such third-party Services or acquisition of such rights shall be Operating Costs in accordance with Section 7.2.1. Operator, for the benefit of the Owners, shall use commercially reasonable efforts to obtain from all subcontractors and suppliers, including any subcontractors and suppliers who are Affiliates of Operator, customary guarantees and warranties to the extent available with respect to the equipment, goods, services or other work provided or performed by such subcontractor and supplier. Notwithstanding the foregoing or anything to the contrary, Operator shall not, without the prior written approval of Non-Operator Owner, such approval not to be unreasonably withheld, conditioned or delayed, procure or enter into any agreement with any third-party subcontractor with respect to the Services with a cost included in the Operating Costs in excess of $500,000 in any Year. Each agreement with a third-party subcontractor shall reflect costs that are on an arm's-length basis and no greater in any material respect than Operator could reasonably provide on Operator's own (or through its Affiliates) without material hardship.

14.4.2 Operator may delegate any obligations hereunder to one or more Affiliates, or designate one or more Affiliates as subagents for the performance of its obligations, and, to the extent such Affiliate performs or acts as subagent with respect to any obligation of Operator hereunder, such Affiliate shall enjoy the rights and benefits of Operator pursuant to this Agreement (including, for the avoidance of doubt, Article X and Article XI hereof). Notwithstanding the foregoing, Operator shall not, without the prior written approval of Non-Operator Owner, such approval not to be unreasonably withheld, conditioned, or delayed, procure or enter into any agreement with any of its Affiliates (other than for Facility Personnel to perform the Services) (i) with a committed value in excess of $500,000 or (ii) that may not be cancelled by or at the request of Non-Operator Owner upon no more than ninety (90) days' notice without penalty. Each agreement with an Affiliate of Operator, other than for Facility Personnel to perform the Services, shall reflect costs that are no greater in any material respect than Operator could obtain on an arm's-length basis with a bona fide third party at such time. Notwithstanding anything to the contrary in this Agreement, Operator shall be permitted to delegate any of its rights, duties and obligations under this Agreement and the Ownership Agreement to AEPSC without the consent of Non-Operator Owner, subject to Section 14.4.3.

14.4.3 If one or more Affiliates perform Services as subagents or subcontractors hereunder, Service Provider shall remain liable for such Affiliate's obligations hereunder and for any breach by such Affiliate of the terms of this Agreement (to the same extent as if such breach was committed by Service Provider).

14.5 Not for Benefit of Third Parties. Except where a contrary intention is expressly stated, this Agreement and each provision hereof are for the exclusive benefit of the Parties that executed this Agreement and not for the benefit of any third party.

14.6 Force Majeure.

14.6.1 Events Constituting Force Majeure. A "Force Majeure Event" is any event that (i) restricts or prevents performance under this Agreement, (ii) is not within the reasonable control of the Party affected or caused by the fault or negligence of the affected Party and (iii) cannot be overcome or avoided by the exercise of due care. Force Majeure Events include the following, so long as in each case the requirements of the foregoing clauses (i), (ii) and (iii) are satisfied, failure of a Party to perform due to drought, flood, earthquake, storm, fire, lightning, tornado or other unusually severe storm or environmental conditions, epidemic, war (whether declared or undeclared), terrorism (whether domestic or foreign, state-sponsored or otherwise), revolution, insurrection, riot, civil disturbances, protests, sabotage (but not including any sabotage involving personnel of Operator), work stoppages (i.e., strikes) (but not including any work stoppages or strikes involving any personnel of Operator, whether on-site or off-site), accident or curtailment of supply, unavailability of construction materials or replacement equipment beyond the affected Party's control, inability to obtain and maintain Permits from any Governmental Authority for the Facility, other acts or omissions of any Governmental Authority, including any form of compulsory government acquisition or condemnation of all or part of the Facility (including a "taking"), restraint by court order, changes in Applicable Law that affect performance under this Agreement, other acts of Governmental Authorities including in response to any of the foregoing. Except for the obligation of each Party to make payments of amounts owed to the other Party, each Party is excused from performance and will not be considered to be in default in respect to any obligation if and to the extent that performance of such obligation is prevented by a Force Majeure Event. Neither Party shall be relieved of its obligations under this Agreement solely because of increased costs or other adverse economic consequences that may be incurred through the performance of such obligations.

14.6.2 Notice. If a Party's ability to perform its obligations under this Agreement is affected by a Force Majeure Event, the Party claiming such inability shall (i) promptly notify the other Party of the Force Majeure Event, its cause, its anticipated duration and any action being taken to avoid or minimize its effect and confirm the same in writing within three (3) Business Days of its discovery, (ii) promptly supply such available information about the Force Majeure Event and its cause as reasonably may be requested by the other Party and (iii) work diligently to remove the cause of the Force Majeure Event or to lessen its effect.

14.6.3 Scope. The suspension of performance arising from a Force Majeure Event shall be of no greater scope and no longer duration than necessary. The excused Party shall use its reasonable best efforts to remedy its inability to perform.

14.7 Dispute Resolution. Any and all disputes shall be resolved pursuant to the dispute resolution procedures set forth in the Ownership Agreement.

14.8 Amendments. No amendments or modifications of this Agreement are valid unless in writing and signed by duly authorized representatives of the Parties.

14.9 Survival. Notwithstanding any provisions to the contrary, the obligations set forth in Article VII and Article VIII, Article X, Article XI and Article XII, Article XIV the limitations on liabilities set forth in Article XI will survive, in full force, the expiration or termination of this Agreement.

14.10 No Waiver. No delay, waiver or omission by the Non-Operator Owner or Operator to exercise any right or power arising from any breach or default by the Non-Operator Owner or Operator with respect to any of the terms, provisions or covenants of this Agreement shall be construed to be a waiver by the Non-Operator Owner or Operator of any subsequent breach or default of the same or other terms, provisions or covenants on the part of the Non-Operator Owner or Operator.

14.11 Notices. Any written notice required or permitted under this Agreement shall be deemed to have been duly given on the date of receipt, and shall be either delivered personally to the Party to whom notice is given, or mailed to the Party to whom notice is to be given, by facsimile, courier service or first-class registered or certified mail, return receipt requested, postage prepaid, and addressed to the addressee at the address indicated below, or at the most recent address specified by written notice given in the manner provided in this Section 14.11:

If to Operator:

[_________________]
[_________________]
[_________________]

If to the Non-Operator Owner:

[_________________]
[_________________]
[_________________]

14.12 Representations and Warranties. Each Party represents and warrants to the other Party that, as of the date hereof:

14.12.1 Existence. It is duly organized and validly existing under the laws of the state of its organization and has all requisite power and authority to own its property and assets and conduct its business as presently conducted or proposed to be conducted under this Agreement.

14.12.2 Authority. It has the power and authority to execute and deliver this Agreement, to consummate the transactions contemplated hereby and to perform its obligations hereunder.

14.12.3 Validity. It has taken all necessary action to authorize its execution, delivery and performance of this Agreement, and this Agreement constitutes the valid, legal and binding obligation of such Party enforceable against it in accordance with its terms, except as such enforcement may be limited by Bankruptcy, insolvency, moratorium or similar laws affecting the rights of creditors or by general equitable principles (whether considered in a proceeding in equity or at law).

14.12.4 No Conflict. Neither the execution or delivery of this Agreement, the performance by such Party of its obligations in connection with the transactions contemplated hereby, nor the fulfillment of the terms and conditions hereof, conflicts with or violates any provision of its constituting documents.

14.12.5 No Consent. No consent or approval (including any Permit that such warranting Party is required to obtain) is required from any third party (including any Governmental Authority) for either the valid execution and delivery of this Agreement, or the performance by such Party of its obligations under this Agreement, except such as have been duly obtained or will be obtained in the ordinary course of business.

14.12.6 No Breach. None of the execution or delivery of this Agreement, the performance by such Party of its obligations in connection with the transactions contemplated hereby, or the fulfillment of the terms and conditions hereof either conflicts with, violates or results in a breach in any material respect of, any Applicable Law currently in effect, or conflicts with, violates or results in a breach of, or constitutes a default under or results in the imposition or creation of, any lien or Encumbrance under any material agreement or instrument to which it is a party or by which it or any of its properties or assets are bound.

14.12.7 No Material Claims. It is not a party to any legal, administrative, arbitral or other proceeding, investigation or controversy pending or threatened that would adversely affect such Party's ability to perform its obligations under this Agreement.

14.13 Additional Representation and Warranty by Operator. Operator further represents and warrants to the Non-Operator Owner that it has, or has obtained through the retention of a qualified operations and maintenance service provider, substantial expertise and experience in the operation and maintenance of comparable power generation facilities and it, or its applicable subcontractor, is fully qualified to provide such services at the Facility in accordance with the terms of this Agreement.

14.14 Counterparts. The Parties may execute this Agreement in counterparts that, when signed by each of the Parties, constitute one and the same instrument. Thereafter, each counterpart shall be deemed an original instrument as against any Party who has signed it. Delivery of an executed counterpart of this Agreement by facsimile or electronic transmission shall be effective as delivery of a manually executed counterpart of this Agreement.

14.15 Governing Law; Venue; Waiver of Jury Trial. The interpretation and performance of this Agreement is governed by and shall be construed in accordance with the laws of the State of New York, exclusive of the conflicts of law provisions thereof that would require the application of the laws of a different jurisdiction. Each Party hereby agrees that any Action arising out of or relating to this Agreement brought by a Party(or any of their respective successors or assigns) shall be brought and determined in any state or federal court sitting in the State of New York, within the Borough of Manhattan, City of New York, and the Parties hereby irrevocably submit to the exclusive jurisdiction of the aforesaid courts for themselves and with respect to their property, generally and unconditionally, with regard to any such Action arising out of or relating to this Agreement and the transactions contemplated hereby, and the appellate courts from any thereof in connection with any action arising out of or relating to this Agreement or any other agreement related to the Facility or any Facility asset and the transactions contemplated hereby, and consents that any such action may be brought in such courts and waives any objection it may now or hereafter have to the venue of any such action in any such court or that such action was brought in an inconvenient court. EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ALL RIGHTS TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING TO THIS AGREEMENT.

14.16 Interpretation. Titles or captions contained in this Agreement are inserted only as a matter of convenience and for reference, and in no way define, limit, extend, describe or otherwise affect the scope or meaning of this Agreement or the intent of any provision hereof. All exhibits and appendices attached hereto are considered a part hereof as though fully set forth herein. This Agreement was jointly drafted and negotiated by the Parties. In the event of a dispute, this Agreement shall not be construed against either Party based upon its drafting.

14.17 Severability. If any provision of this Agreement, or the application of any such provision to any Person or circumstance, is held invalid by any court or other forum of competent jurisdiction, the remainder of this Agreement, or the application of such provision to Persons or circumstances other than those as to which it is held invalid, shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in a manner materially adverse to a Party. Upon any such determination of invalidity, the Parties shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties as closely as possible in an acceptable manner in order that this Agreement is consummated as originally contemplated to the greatest extent possible.

14.18 Cooperation in Financing. Operator shall execute and deliver any customary and reasonable agreement and consent to assignment, together with an opinion of counsel at Non-Operator Owner's expense, as may be reasonably requested by Non-Operator Owner in connection with any financing of the Facility. Operator shall promptly respond to reasonable requests, including requests for management presentations, by Non-Operator Owner and any of its Lenders or their representatives, in each case at Non-Operator Owner's sole cost and expense, for information regarding the Operator and its performance of its duties hereunder and the operation, maintenance and administration of the Facility. Operator agrees to use commercially reasonable efforts to cooperate with any of Non-Operator Owner's Lenders and their representatives and to provide such Lenders and representatives with reasonable access to and tours of the Facility (including review of documents, materials, records and accounts), in each case at Non-Operator Owner's sole cost and expense.

[*Signature page follows.*]

IN WITNESS WHEREOF, the Parties have executed this Agreement through their duly authorized officers as of the date set forth in the preamble to this Agreement.

**KENTUCKY POWER COMPANY**

By: ________________________________
Name:
Title:

**WHEELING POWER COMPANY**

By: ______________________________________
Name:
Title:

## APPENDIX A – SCOPE OF SERVICES

| Task Name | Description |
|---|---|
| **Routine Services** | Provide operational services as reasonably necessary for electrical power generation. |
| **Detailed Programs** | Implement Operator human resources program. Implement Operator-drafted, Owner-approved programs in safety, administration, maintenance, and training. Implement Facility's existing programs in operating, maintenance, chemistry, NERC and environmental compliance (or, at the Operating Committee's request, develop or enhance such programs at actual cost and implement). Ensure compliance with NERC requirements, Environmental Law, Applicable Law, and all Permits. |
| **Routine Maintenance** | Perform routine and preventive maintenance actions on all Facility systems and equipment in accordance with vendor instructions and the maintenance plan for the Facility. This program includes:<br><br>**Service Checks** – Conduct visual equipment inspections and log significant parameters such as pressures, temperatures, and flow rates. Trend and analyze this information as appropriate.<br><br>**Routine and Fixed Interval Maintenance** –Identify preventive maintenance requirements. Schedule and assign routine maintenance during Facility operation, planned outages, and forced or unscheduled outages. |
| **Predictive Maintenance Program** | As appropriate, conduct/oversee predictive maintenance within the cost-effective capability of the Facility Personnel. For those maintenance requirements that are not cost-effective for the Facility Personnel, oversee predictive maintenance services provided by vendors. |
| **Major Maintenance and Repairs** | In coordination with and support of the Facility Agreements and generation plan, arrange for scheduled inspections and overhauls on major equipment. Retain vendors for the benefit of the Owners for unscheduled major repairs as required and manage and oversee repairs and modifications. |
| **Capital Improvements** | Conduct/oversee all capital improvements. As appropriate, retain vendors for the benefit of the Owners to design, construct and implement capital improvements. |
| **Facility Outages** | Use commercially reasonable efforts to manage all Facility outages (planned, unscheduled, forced) to optimize outage duration and impact on production: |

| Task Name | Description |
|---|---|
| | **Task Assignment** – Identify and schedule all maintenance that requires a Facility outage or equipment to be taken out of service.<br>**Work Schedule –** Develop and implement a schedule to track material outage preparations, work and testing, including corrective maintenance actions, contractor work and scheduled preventive maintenance. Conduct preparations to support this plan, including ordering and receiving required spare parts. |
| **Assistance to the Non-Operator Owner and Operating Committee** | Provide assistance to the Non-Operator Owner and the Operating Committee, as reasonably requested with the execution of the Non-Operator Owner's and the Operating committee's duties relative to operation of the Facility. |
| **Facility Administration** | Conduct administration to meet Operator requirements and Owners' goals, including:<br>**Budgets** – Prepare annual Budgets and submit them for Operating Committee approval in accordance with the Ownership Agreement and this Agreement. Following approval, manage operations and expenditures to comply with each Budget. Generate budget variance reports, as required.<br>**Procurement** – Establish and implement a purchasing system. Procure, for the benefit of the Owners, including negotiations and contracting, for all materials, equipment, chemicals, supplies, services, parts, and other miscellaneous items required for the provision of the Services. Pay all invoices in a timely manner. Provide credit support as required by third parties for the operation of the Facility, including contract counterparties and Governmental Authorities. Minimize Owner costs as much as feasible.<br>**Inventory Control** – Implement a cost-effective inventory control system designed to ensure that spare parts, materials, and supplies are properly stored and accounted for and that adequate supplies are available at all times to support the provision of the Services.<br>**Personnel Matters** – In compliance with Operator programs and policies, manage all payroll and employee relations, labor relations, and independent contractor issues, as required. These tasks include: employment; compensation and benefits; initial training; and employee and independent contractor relations. Provide reasonable support to recruit, hire, transfer, or otherwise acquire and retain qualified Facility Personnel to maintain the staffing levels and skill mix required for successful long-term provision of the Services. |

| Task Name | Description |
|---|---|
| | **Community Relations** – In coordination with and with the approval of the Operating Committee, conduct a community relations program to establish the Facility and its employees as "good citizens" in the local community.<br><br>**Regulatory –** Perform all duties set forth in Section 7.8 of the Ownership Agreement with respect to Emission Allowances (as defined therein). |
| **Work Assignment** | Assign work to either Facility Personnel or vendors as cost-effective and appropriate based on overall guidance from the Operating Committee. Normally, Facility Personnel conduct preventive maintenance and actions requiring a high degree of Facility knowledge and vendors perform tasks needing equipment or expertise that are not cost-effective to maintain at the Facility. Vendors also perform tasks that make sense to minimize outage time and costs. |
| **Buildings and Grounds** | Arrange for janitorial, garbage pickup and landscape services and maintain all access roads, office buildings, and other structures in reasonable repair. |
| **Reports** | Prepare and submit operation and maintenance service reports as requested relative to performance, including environmental compliance records, maintenance and repair status, Facility operating data, and any other information reasonably requested by the Operating Committee or the Non-Operator Owner. |
| **Security** | Implement or arrange for implementation of security measures in accordance with the Operating Committee-approved Facility security plan. |
| **Safety** | Continue to implement Corporate and Plant Level Safety Programs including on-site visits and discussions at the facility. |
| **PJM Capacity Analysis** | Analysis and plant level information to PJM as part of PJM's FRR or RPM Capacity Market requirements |
| **Information Systems** | Manage the Facility's information technology infrastructure, including phone systems, internet connectivity, hardware and software. Implement or arrange for implementation of cybersecurity policies and procedures in compliance with NERC requirements and Applicable Law, in accordance with the Operating Committee-approved Facility cybersecurity plan. |
| **Training Program** | Implement a continuing program of training designed to orient new Facility Personnel, refresh/cross-train existing Facility Personnel, qualify/re-qualify Facility Personnel, and keep all Facility Personnel |

| Task Name | Description |
|---|---|
| | aware of Operating Committee -approved Facility safety requirements and emergency procedures. This program includes specialty skills training. |
| **Drawing/Manual Maintenance** | Maintain the Facility library and update the Manuals and vendor service manuals. Update (or arrange for updating) Facility drawings to reflect changes to the as-built configuration. In addition to document management, maintain physical Facility configuration control. |

| Task Name | Description |
| --- | --- |
| **Fuel Purchasing and Handling** | • Procure coal, reagents, fuel oil supply or transportation service agreements as needed to operate the Facility and establish and maintain reserves of coal in common stock piles of such quality and in such quantities as the Operating Committee shall determine<br>• Contract administration for Fuel supply contracts along with legal review.<br>• Third Party Settlements of fuel related supply and inventory tracking in ComTrac system<br>• Joint Books Accounting to prepare information for billing among co-owners per agreement<br>• Analysis of fuel related costs for data requests from regulatory bodies or joint owner<br>• Provide fuel reserves against interruptions of normal fuel supply and as is necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from such coal stock piles by the Facility during each month.<br>• Receive coal and provide fuel handling<br>• Fuel coordinator functions to review fuel quality with third party suppliers at coal or limestone facilities.<br>• Administer and reconcile volumes of all fuel with suppliers<br>• Administer and comply with the requirements set forth in the Facility's fuel agreements, including quality testing and invoice review and approval<br>• Administer and comply with the requirements set forth in the Facility's coal ash, gypsum and combustion byproduct disposal and sales agreements, including invoice review and approval |

| Task Name | Description |
|---|---|
| **Day Ahead and Real Time Market Operations** | • Unit Generation Dispatch – Monitor signals and take direction from PJM for generating units. Relay these directions, commitments and settings to the Unit Operators and Controls. Relay information on real time unit conditions to Transmission Owner (TO) and PJM.<br>• GADS Reporting – Create GADS events as they are scheduled or occur. Submit monthly event reporting as required by NERC and PJM.<br>• Outage Support and Communications to PJM – Relay outage/curtailment information from plant personnel to PJM. Schedule maintenance and planned outages/curtailments, and maintain updates as they arise.<br>• Unit Characteristic Updates to PJM – Provide any relevant configuration updates related to generating units to PJM that may occur.<br>• Telemetry – Maintain current real time telemetry to/from the plant, PJM and Market Operations control center. |
| **Administration of Contracts** | • Administer, perform and enforce all contractual obligations and arrangements, including all warranties applicable thereto, entered into by Operator for the benefit of the Owners with respect to the Facility<br>• Act as agent on behalf of the Non-Operating Owner with respect to the administration, performance and enforcement of any contracts or purchase orders (including fuel supply or transportation contracts) with respect to the Facility that are in the name of the Non-Operator Owner as a result of the Non-Operator Owner having served as the Operator prior to the Effective Date |
| **Insurance** | • Procure on behalf of each Owner such property and other insurance policies as required by the insurance program established by the Operating Committee in accordance with the Ownership Agreement. |

| Task Name | Description |
|---|---|
| **Decommissioning** | • Manage and contract with vendors and other parties to perform Decommissioning Work. This includes the management of required regulatory filings, permitting, engineering assessments, and the contracting for demolition and or liability transfers. Upon mutual agreement between Operator and the Operating Committee, Operator may conduct all or a portion of the Facility and/or Site Decommissioning from its and its Affiliates resources. |

## APPENDIX B – INITIAL BUDGET AND PLAN

[To be attached as of the Effective Date]

## APPENDIX C – OPERATING COSTS WORKSHEET/SAMPLE INVOICE

[See attached.]

**PAGE 1**

INVOICE # **xxx-xxxxxxxx**

**Month of Billing**

**PAYMENT DUE BY:** **Date Due**

Kentucky Power Company
Attn: xxxx
Address
City, State Zip Code

Dear xxxx:

**This is the billing report for Actual charges for the month of Month of billing for the Mitchell Generating Plant. Please include the invoice number above on your wire transfer to the receiving bank listed on that report. If you have any questions please call: xxxx at xxx-xxx-xxx or E-mail to xxx@aep.com**

| **Operating & Maintenance Agreement as Operator Article VII, Section 2:** | **Amount** |
|---|---|
| i. KPCO'S Actual cost of coal inventory receipts of Mitchell Power Plant. | $3,914,522.89 |
| ii. KPCO'S Actual cost of coal handling inventory receipts of Mitchell Power Plant. | $249,855.00 |
| iii. KPCO'S Actual cost of fuel oil inventory receipts of Mitchell Power Plant. | $12,185.50 |
| iv. KPCO'S Actual cost of Limestone inventory receipts of Mitchell Power Plant. | $55,080.45 |
| v. KPCO'S Actual cost of Urea inventory receipts of Mitchell Power Plant. | $19,351.35 |
| vi. KPCO's share of total cost of operation of Mitchell Power Plant. | $227,744.80 |
| vii. KPCO's share of total cost of maintenance of Mitchell Power Plant. | $295,700.00 |
| viii. KPCO's share of total cost of fuel handling/fly ash of Mitchell Power Plant. | $50,000.00 |
| ix. KPCO's share of A&G expenses. | $145,000.00 |
| x. KPCO's share of Other Operating Costs. | $0.00 |
| ***Total Operating Expenses*** | $4,969,439.98 |
| KPCo's share of Capital Expenditures | $100,000.00 |
| Storeroom Inventory Activity | $150,000.00 |
| ***TOTAL AMOUNT DUE WHEELING POWER COMPANY*** | **$5,219,439.98** |

| ***Wiring Instructions*** | | |
|---|---|---|
| Name on Acct: | Wheeling Power Co | |
| Bank: | Bank | |
| Acct: | Acct | |
| ABA: | ABA | |
| Ref: | Invoice #, | xxx-xxxxxxxx |

**AEP CONFIDENTIAL**

[RATE SCHEDULE NO. 303]

# MITCHELL PLANT OWNERSHIP AGREEMENT

KENTUCKY POWER COMPANY

and

WHEELING POWER COMPANY

THIS MITCHELL PLANT OWNERSHIP AGREEMENT (this "Agreement"), with an effective date of [_______] (the "Effective Date"), is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo"); Wheeling Power Company, a West Virginia corporation ("WPCo") (such parties hereinafter sometimes referred to as an "Owner" and together the "Owners"); and, solely with respect to Section 13.4, American Electric Power Service Corporation, a New York corporation ("AEPSC").

WITNESSETH:

WHEREAS, KPCo and WPCo, as of the date hereof, each own a fifty percent (50%) undivided ownership interest in the Mitchell Power Generation Facility (each such percentage interest, an Owner's "Ownership Interest"), which consists of two coal-fired generating units (each, a "Unit"), with each Unit having a nominal nameplate capacity of 800 MW, located in Moundsville, West Virginia (as further defined herein, the "Mitchell Plant");

WHEREAS, KPCo, WPCo and AEPSC are parties to that certain Mitchell Plant Operating Agreement, dated as of December 31, 2014 (the "Original Operating Agreement");

WHEREAS, the Original Operating Agreement sets forth certain rights and obligations of the Owners and AEPSC with respect to the Mitchell Plant and the Owners' ownership thereof;

WHEREAS, pursuant to the Original Operating Agreement, KPCo is responsible for the day-to-day operations and maintenance of the Mitchell Plant;

WHEREAS, the Owners and AEPSC desire to replace the Original Operating Agreement to set forth the rights and obligations of the Owners with respect to the Mitchell Plant and their ownership thereof and to remove AEPSC as a party thereto;

WHEREAS, in connection with the execution of this Agreement, the Owners desire to execute a separate operations and management agreement to provide for the day-to-day operation and maintenance responsibilities in respect of the Mitchell Plant (as may be amended from time to time the "O&M Agreement");

WHEREAS, the Owners have agreed that, subject to the terms and conditions of the O&M Agreement, on and after the Effective Date WPCo shall replace KPCo as the operator of the Mitchell Plant (the "Operator"); and

WHEREAS, on and subject to the terms and conditions of this Agreement, the Owners have committed to undertake a Buyout Transaction (as hereinafter defined), pursuant to which WPCo shall purchase KPCo's Ownership Interest on or prior to December 31, 2028, unless an Early Retirement Event (as hereinafter defined) occurs.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories hereto agree as follows:

# ARTICLE ONE
# OWNERSHIP AND OPERATIONS

1.1 To the greatest extent permitted by Applicable Law, the Mitchell Plant and all assets (tangible and intangible) and property (real and personal) owned, leased, held, developed, constructed or acquired solely for or in connection with the Mitchell Plant or the operation, maintenance or Decommissioning of the Mitchell Plant by or on behalf of an Owner or the Owners (together, the "Project Assets") shall be owned and held and deemed to be owned and held by the Owners as tenants in common in proportion to their respective Ownership Interests (except for any capital items owned in a different proportion in accordance with Section 1.8) or, in the event any Project Asset cannot be held directly by both of the Owners due to, inter alia, any pre-existing legal or contractual restrictions that cannot be altered or satisfied or where effectuating such ownership structure would result in unreasonable additional expense to the Owners, by the Operator as trustee for the Owners as tenants in common in proportion to their respective Ownership Interest. If the ownership of any Project Asset is registered or recorded in the name of one of the Owners, and notwithstanding the Owners' efforts such Project Asset cannot be held directly by both Owners as contemplated above, then such Owner in whose name ownership is registered or recorded shall hold such Project Asset in trust for itself and the other Owner in proportion to their respective Ownership Interests and, to the extent necessary or requested by the Operator or other Owner, make such Project Assets (or the benefits thereof) available for the use and benefit of the Owners (in proportion with their respective Ownership Interests), including, to the extent consistent with the foregoing, by such Owner subcontracting, sublicensing, subleasing, delegating or granting a limited power of attorney or similar appointment as agent to Operator to administer such Project Assets.

1.2 At the request of either Owner, and in accordance with Section 1.1, each Owner and the Operator shall execute all documents and do all things necessary or appropriate to register or record the Project Assets in the names of the Owners in proportion to their respective Ownership Interests (or such different proportion as any capital item may be owned in accordance with Section 1.8).

1.3 All assets (tangible and intangible) and property (real and personal) held, developed, constructed or acquired by or on behalf of the Operator for or on behalf of the Owners jointly, or any of them, shall constitute "Project Assets" subject to the ownership of both Owners as set forth in Sections 1.1 and 1.2. Except as otherwise agreed by the Owners, the Operator shall not have any right, title or interest in or to any such assets, or in or to any money paid to, collected or received by the Operator for or on behalf of either Owner, except as the agent or representative of, or for the use and benefit of, such Owners as set forth in this Agreement and in proportion to each Owner's respective Ownership Interest.

1.4 Each Owner hereby waives any rights it may have at law or equity to bring an action for partition or division of the Mitchell Plant or any Project Asset or any contracts related thereto, and agrees that it shall not (a) seek partition or division of the Mitchell Plant or any Project Asset or any contracts related thereto, or (b) take any action, whether by way of any court order or otherwise, for physical partition or judicial sale in lieu of partition of the Mitchell Plant or any Project Asset or any contracts related thereto. Nothing in this Section 1.4 shall affect the right of either Owner to dispatch its respective share of the Total Net Capability under Article Two or to Dispose of its Ownership Interest in accordance with Article Nine.

1.5 On and after the Effective Date, WPCo shall be the Operator responsible for the day-to-day operations and maintenance of the Mitchell Plant and shall operate, maintain and Decommission the Mitchell Plant for the sole benefit (and on behalf) of the Owners and in accordance with the terms and conditions of this Agreement and the O&M Agreement. KPCo agrees to take all actions reasonably necessary to facilitate WPCo's operation, maintenance and Decommissioning of the Mitchell Plant pursuant to the terms of the O&M Agreement, including providing or permitting reasonable access to the Mitchell Plant to third party contractors and other contract counterparties of each Owner or the Operator with respect to the administration, implementation and satisfaction of such contracts or agreements executed or assumed by the Operator on behalf of either Owner relating to the Mitchell Plant, including all Facility Agreements (as defined in the O&M Agreement).

1.6 The Owners shall establish and maintain such bank accounts as may from time to time be required or appropriate for paying the costs and expenses, including capital expenditures, in respect of the ownership, operation, maintenance and Decommissioning of the Mitchell Plant. The Owners shall designate only the Operator, and its representatives as reasonably requested by the Operator, as authorized signatories to such bank accounts. All withdrawals made by the Operator (or its representatives) from such bank accounts shall be made only in connection with the performance of the Operator's obligations set forth in this Agreement and the O&M Agreement.

1.7 The initial capital budget for the period from the Effective Date through December 31, 2028 (including agreed allocations of costs for capital projects between the Owners) (the "Capital Budget"), the initial annual operating budget and the initial forecast of operating and capital costs to be incurred for the period from the Effective Date through December 31, 2028 are attached hereto as Exhibit A.

1.8 Notwithstanding the provisions of this Article One, to the extent that either Owner funds or bears an amount greater than 50% of any capital expenditures or ELG Capital Expenditures as contemplated in the Capital Budget or this Agreement, the directly resulting portion of any property, plant and equipment, or improvements thereto shall be owned by the Owners in proportion to their respective amounts funded and shall be included only in such proportion in each Owner's ownership accounts for regulatory, accounting, tax and other purposes.

## ARTICLE TWO
## APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The total net capability of the Mitchell Plant at low-voltage busses of the Units, after taking into account auxiliary load demand, is 1,560,000 kilowatts (the "Total Net Capability") as of the Effective Date. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The total net generation of the Mitchell Plant during a given period, as determined by the requirements of each Owner, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for each Unit during such period (the "Total Net Generation").

2.3 Each Owner shall be entitled to receive 50% of the Total Net Capability and the Total Net Generation (with respect to each Owner, such Owner's "Assigned Capacity"), and all associated energy, capacity, ancillary services and other energy products, in accordance with this Agreement.

2.4 Except as may be determined by the Operating Committee in accordance with Section 7.6, in any hour, each Owner shall share 50% of the minimum load responsibility of each Unit.

2.5 In any hour during which any Unit is out of service, the Owners shall bear equally the cost of energy used by the out-of-service Unit's auxiliaries during such hour, which may be provided by the applicable local utility Affiliate of an Owner. Alternatively, the Owners may mutually agree in writing to each provide 50% of such energy.

## ARTICLE THREE
## REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 The Owners shall take all actions within their respective control to cause the Operator, pursuant to the O&M Agreement, from time to time to make or cause to be made any necessary or appropriate additions to, replacements of, and retirements of, capitalizable facilities associated with the Mitchell Plant in accordance with the Capital Budget and the O&M Agreement or as may otherwise be mutually agreed upon by the Owners.

3.2 In the event that, prior to execution and delivery of the Mitchell Interest Purchase Agreement, an Early Retirement Event occurs, each Owner shall (a) cause each Unit to permanently cease operations on December 31, 2028, or such other date permitted by Applicable Law as the Operating Committee may determine, (b) be responsible for, and shall timely pay, 50% of all Decommissioning Costs, (c) cooperate in good faith and take all actions reasonably necessary to facilitate the Decommissioning Work, including negotiating in good faith any contracts or agreements (including liability transfer arrangements) on behalf of either Owner or Operator, including transfers, conveyances or assignments of Facility Equipment (as defined in the O&M Agreement), as reasonably requested by either Owner or Operator to facilitate Decommissioning and (d) take, and/or instruct the Operator pursuant to the O&M Agreement to take, such actions, at the sole cost and expense of WPCo, to continue operating and maintaining the barge loading facilities and gypsum conveyor system at the Mitchell Plant and providing use of such facilities and system to the applicable contract counterparty and its representatives in accordance with, and until the expiration or earlier termination of, the CertainTeed Contract.

## ARTICLE FOUR
## WORKING CAPITAL REQUIREMENTS

4.1 The Owners shall periodically mutually determine the amount, timing and invoicing processes for funds required for use as working capital, for operating, capital and other expenses incurred in the operation, maintenance and Decommissioning (including the

Decommissioning Costs) of the Mitchell Plant, and in buying equipment, materials, parts, fuel and other supplies and services necessary to operate, maintain and Decommission the Mitchell Plant and to make the timely payments of any expenses required under the O&M Agreement.

4.2 Each Owner shall, in accordance with the timing set forth in a determination made pursuant to Section 4.1, promptly provide 50% of any such amount required by the Owners pursuant to Section 4.1, except as otherwise provided for in Section 6.7.

4.3 Each Owner agrees that if such Owner fails at any time during the Term to satisfy the Ratings Requirement, it will, within thirty (30) days of such failure, provide in favor of the other Owner and maintain credit support in the form of (a) a cash deposit, (b) a guaranty issued by an Affiliate of such Owner that satisfies the Ratings Requirement in form and substance reasonably acceptable to the other Owner or (c) a letter of credit in form and substance reasonably acceptable to other Owner, issued by a commercial bank or other financial institution with a Credit Rating of at least "A-" by S&P Global Ratings, or any successor thereto ("S&P") or at least "A3" by Moody's Investors Service, Inc., or any successor thereto ("Moody's"), and in an amount equal to (i) one-half ($^1/_2$) of the then-applicable annual operating budget for the Mitchell Plant established pursuant to Section 7.2 from time to time, plus (ii) the sum of such Owner's allocated amount of capital expenditures for such year contained in the then-applicable Capital Budget, plus (iii) an amount equal to the latest estimate of Decommissioning Costs prepared by the Operator, determined on a net present value basis using a discount rate equal to the WACC as of the date of determination. Such credit support posted in favor of an Owner shall be promptly returned within thirty (30) days of the other Owner furnishing written evidence demonstrating that it satisfies the Ratings Requirement.

4.4 The Operator shall provide such credit support, including guarantees, cash deposits, letters of credit or other forms of credit support, to third parties (including contractual counterparties and Governmental Authorities) as required for the Owners' ownership, operation, maintenance and Decommissioning of the Mitchell Plant. To the extent that the Operator is required to provide such credit support to a third party in connection with any activity performed in respect of the Mitchell Plant under this Agreement (including the procurement of fuel as described in Section 5.1), the Owners shall share the reasonable and documented out-of-pocket cost of the third-party credit support incurred by the Operator (including of any credit support furnished by an Affiliate of the Operator) in accordance with their respective Ownership Interests.

## ARTICLE FIVE
## INVESTMENT IN FUEL

5.1 The Operator shall procure, establish and maintain reserves of coal in common stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply and as is necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from such coal stock piles by each Unit during each month. For purposes of this Agreement, "consumables" shall be as defined in account 502 of the Uniform System of Accounts administered by the Federal Energy Regulatory Commission ("FERC").

5.2 The quality of any coal or consumable product provided by the Operator must be reasonably acceptable to both Owners. Any coal being utilized shall be deemed to be acceptable to the Owners if it meets the following requirements: (a) coal previously utilized at the Mitchell Plant with satisfactory operating performance shall be considered acceptable for use in the Mitchell Plant, unless deemed unacceptable due to a required change of the engineering specifications making the coal no longer viable; (b) coal from any new seam or source shall be acceptable if such supply is shown to perform satisfactorily in the Mitchell Plant and is mutually acceptable to each Owner; or (c) as otherwise mutually agreed to by each Owner. Consumables from any new seam or source shall be acceptable if such supply is shown to perform satisfactorily to both Owners in the Mitchell Plant and conform to the then current engineering specifications for the Mitchell Plant or as otherwise mutually agreed by each Owner.

5.3 Each Owner shall be responsible for, and own, 50% of the investment in the common coal stock piles.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

## ARTICLE SIX
## APPORTIONMENT OF STATION COSTS

6.1 The allocation to the Owners of fuel expense associated with each Unit shall be determined by the Operating Committee as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit-cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the Mitchell Plant fuel in the stock pile and charged to the Mitchell Plant fuel consumed.

(c) In each calendar month, each Owner's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For each calendar month, the Operator will, to the extent practicable and in accordance with the O&M Agreement, determine all of the Mitchell Plant's operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.3 For each calendar month, the Operator will, to the extent practicable and in accordance with the O&M Agreement, determine all the Mitchell Plant's maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 In each calendar month, each Owner's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with this Article Six, shall be allocated as follows:

(a) Each Owner's respective share of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to each Unit or designated as a common expense attributable to both Units. In each calendar month, each Owner's respective share of these expenses shall be proportionate to each Owner's dispatch of the applicable Unit, or both Units in the case of common expenses, over the previous sixty (60) calendar months.

(c) In each calendar month, each Owner shall be responsible for 50% of all other Steam Power Generation Expenses (FERC Accounts 500 - 515) not addressed in Section 6.4(a) and Section 6.4(b). Administrative and General Expenses (FERC Accounts 920 – 935) shall be assigned to the Mitchell Plant through an annual wages and salaries allocator applied to monthly Administrative & General Expenses. Each Owner shall be responsible for 50% of this monthly amount; provided, however, that, for the avoidance of doubt, each Owner shall be individually responsible for any fees, costs or other charges, including but not limited to those imposed by PJM Interconnection, L.L.C. ("PJM") or any regional transmission operator or any other Governmental Authority in respect of, or which are attributable to, the sale or transmission of the capacity or energy associated with its Ownership Interest, as the case may be.

(d) Notwithstanding the foregoing clauses (a) through (c) or anything else in this Agreement or the O&M Agreement to the contrary, in each calendar month, any operations and maintenance or other expenses to the extent attributable to any ELG Upgrade (regardless of the FERC Account to which it is charged) shall be allocated exclusively to and paid by WPCo.

(e) In each calendar month, each Owner's respective share of Construction Work In Progress charged to FERC Account 107 shall be allocated on the same basis as capital expenditures, as set forth in Section 6.7.

(f) In each calendar month, the net change in Mitchell Plant storeroom inventory (inventory purchases less issuances of inventory) charged to FERC Account 154 shall be allocated 50% to each Owner.

(g) Each Owner shall be charged 50% of Operating Costs, as defined in and in accordance with Section 7.2 of the O&M Agreement, except to the extent a different allocation for specific FERC Accounts or otherwise is specified in this Article Six.

6.5 All taxes, duties or assessments levied against or with respect to each Owner's Ownership Interest, or an Owner's purchase, use, ownership or beneficial interest in, or income from, the Mitchell Plant shall be the sole responsibility of, and shall be paid by, the Owner upon whose purchase, use, ownership interest or beneficial interest or income said taxes or assessments are levied. Without limiting the foregoing, in each calendar month, each Owner's respective share of Employee Payroll Taxes charged to FERC Account 408 shall be 50%.

6.6 Notwithstanding any other provision of this Agreement or any other agreement to the contrary, each Owner hereby acknowledges and agrees that (a) each Owner prior to the Effective Date has treated, and subsequent to such date shall continue to treat, the co-ownership and operation of the Mitchell Plant as excluded from Subchapter K of the Internal Revenue Code of 1986, as amended (the "Tax Code"), pursuant to Section 761(a) thereof, for all federal, state and local income tax purposes, (b) each Owner prior to the Effective Date affirmatively elected not to apply any of the provisions of Subchapter K of the Tax Code to such Owner's interest in the Mitchell Plant, with such election having been formally filed in connection with the Owners' applicable income tax returns for the taxable year ending on December 31, 2020 and each Owner has taken all actions necessary to implement such election and (c) each Owner prior to the Effective Date has reported, and subsequent to such date shall report, its share of all income, gains, deductions, losses, credits, etc. from its Ownership Interest on its tax returns consistent with such exclusion from the provisions of Subchapter K of the Tax Code.

6.7 Subject to clauses (b) and (c) below the cost of any replacement, addition, improvement or upgrade of each Unit or any portion of the Mitchell Plant, and any restoration or remediation required in connection therewith, shall be allocated between the Owners in accordance with the allocations for such capital items contained in the Capital Budget. With respect to any such capital item not contained in the Capital Budget, the costs of such capital item shall be allocated as follows, unless the Operating Committee agrees upon a different allocation:

(a) Capital expenditures (other than ELG Capital Expenditures) that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be allocated exclusively to, and paid for by, that Owner.

(b) Notwithstanding anything to the contrary herein, ELG Capital Expenditures shall be allocated exclusively to, and paid for exclusively by, WPCo (subject to adjustment of the Buyout Price in accordance with Section 9.6) and CCR Capital Expenditures shall be allocated 50% to (and paid for by) each Owner; provided, that, the Operating Committee shall engage or retain a Technical Expert to make recommendations with respect to determining which capital expenditures are ELG Capital Expenditures and which capital expenditures are CCR Capital Expenditures.

(c) Notwithstanding anything to the contrary herein, if the in-service date of a capital item is reasonably anticipated by the Operating Committee to be after December 31, 2028, then the capital expenditures for such capital item shall be allocated exclusively to, and paid for by, WPCo.

(d) If the Operating Committee determines, including based on Depreciable Lives of similar assets previously approved by applicable Governmental Authorities, that a capital item (other than an ELG Upgrade) has a Depreciable Life that extends beyond December 31, 2028, then (i) KPCo shall be responsible for and shall pay 50% of the expenditures for such capital item, multiplied by (A) the number of months (not to exceed the Depreciable Life of such capital item) between the reasonably anticipated in-service date of such capital item and December 31, 2028, divided by (B) the Depreciable Life of such capital item and (ii) WPCo shall be responsible for the remaining amount of such capital expenditure not allocated to KPCo pursuant to the foregoing clause (i).

(e) Any other capital expenditures shall be allocated 50% to (and paid for by) each Owner, subject to the written approval of the Operating Committee for budget overruns to the extent required pursuant to Section 5.3.2 of the O&M Agreement.

6.8 In the event of an Early Retirement Event, each Owner shall be responsible for 50% of all Decommissioning Costs, unless a different allocation is expressly specified for such item in the Capital Budget (as agreed by the Owners) or the Owners mutually agree to allocate such costs in another manner; provided that nothing in this Section 6.8 shall affect the inclusion of Decommissioning Costs in the calculation of the Buyout Price pursuant to Section 9.6.

6.9 Notwithstanding anything contained in this Agreement, an Owner's obligation to pay its obligations under this Agreement shall not in any way be conditioned upon or affected by any regulatory order or other determination disallowing, limiting or deferring rate recovery of the costs and expenses paid or payable by an Owner in respect of its Ownership Interest.

## ARTICLE SEVEN
## OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, each Owner shall name one representative (the "Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement and the O&M Agreement. An Owner may change its Operating Representative or alternate at any time by written notice to the other Owner. The Operating Representatives for the respective Owners, or their alternates, shall comprise the "Operating Committee". All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. If the Operating Representatives are unable to agree on any matter, such matter will be resolved through the dispute resolution procedures set forth in Article Twelve.

7.2 The Operating Committee shall have the following responsibilities, which decisions are reserved exclusively for the Operating Committee and may not be made individually by the Operator or any Owner:

(a) Review and approval of any amendments to the Capital Budget, and adoption of an annual operating budget, annual operating plan and a six-year forecast of operating and capital expenses, each as delivered to the Operating Committee by the Operator pursuant to Section 7.8, including determination of the emission allowances required to be acquired by each Owner with respect to their Ownership Interests; provided, that an Owner's Operating Representative shall have the right to amend the Capital Budget solely to include any capital expenditures for which such Owner shall be allocated greater than 75% of the costs pursuant to Section 6.7, up to an aggregate amount of such capital expenditures that does not exceed $3 million per year allocated to the other Owner. Allocations of new capital expenditures added to the Capital Budget shall be consistent with Section 6.7; provided, that if the Operating Committee cannot agree upon the Depreciable Life of a capital item or the allocation of a capital expenditure between the Owners (including determining which capital expenditures are ELG Capital Expenditures and which capital expenditures are CCR Capital Expenditures), the matter shall be resolved in accordance with the Technical Dispute resolution procedures set forth in Section 12.1 and Section 12.3 and the Owners shall implement any resolution of the Technical Dispute through adjustments or true-up payments, as appropriate. If the Operating Committee fails to adopt an annual operating budget, the approved annual operating budget from the previous year (other than one-time or other non-recurring or inapplicable items) shall apply until such time as the new annual operating budget is approved.

(b) Establishment, modification and review of procedures, guidelines and systems for scheduling and dispatch, notification of dispatch, and Unit commitment under this Agreement, including any Unit-commitment pursuant to Section 7.5 or Section 7.6.

(c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages at the Mitchell Plant, as well as the return the Mitchell Plant to availability following an unplanned outage. The Operating Committee shall use commercially reasonable efforts, consistent with Prudent Operation and Maintenance Practices (as defined in the O&M Agreement), to schedule the implementation of ELG Upgrades during planned maintenance and repair outages so as to eliminate or minimize incremental outages.

(d) To the extent not included in the Capital Budget, decisions on capital projects, including Unit upgrades and re-powering, except that an Owner's Operating Representative shall have the right to approve any such capital projects for which such Owner shall be allocated greater than 75% of the costs pursuant to Section 6.7 and Section 7.2(a).

(e) Determinations as to allocations between the Owners of expenses pursuant to Section 6.1.

(f) Determinations as to changes in the Unit capability.

(g) Establishment and modification of billing procedures under this Agreement or under the O&M Agreement.

(h) Approval of material contracts for fuel supply or transportation.

(i) Establishment and modification of specifications of fuels; oversight of fuel procurement, inspection and certification arrangements, policies and procedures; and management of fuel inventories for the Mitchell Plant.

(j) Establishment of, termination of, and approval of any change or amendment to the operating arrangements (including the O&M Agreement) between the Owners and the Operator (or any successor Operator or replacement third-party Operator) and selection of any replacement Operator, except as otherwise permitted by Section 7.9.

(k) Review and approval of plans and procedures designed to ensure compliance at the Mitchell Plant with all Applicable Law, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one Unit for compliance.

(l) Amendment, termination, extension or modification of the O&M Agreement, and supervision of the performance of, and provision of direction as needed to, the Operator.

(m) Decisions regarding the retirement, permanent removal from service or Decommissioning of a Unit or any material portion of the Mitchell Plant and any restoration or remediation required in connection therewith.

(n) Establishment of an insurance program to provide property and general liability insurance on behalf of each Owner, to be procured by the Operator pursuant to the O&M Agreement.

(o) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least quarterly, or at such other frequency as determined by the Operating Committee, and at such other times as an Owner may reasonably request. The Operator shall provide operations reports to the Operating Committee each month (presented on a monthly basis) and each quarter (presented on a quarterly basis) substantially in the form of Exhibit B hereto.

7.4 The Owners and the Operator shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 Subject to Section 7.6, each Unit shall be scheduled and dispatched on a joint and equal basis by the Owners, including bidding the Mitchell Plant or any Unit as a single bid, consistent with procedures and guidelines established by the Operating Committee. The Owners shall make an initial Unit-commitment one business day ahead of real-time dispatch, or on such other timetable as the Operating Committee may determine. In each calendar month, each Owner's respective shares of the Emissions Allowances consumed as determined in accordance with the provisions of Section 7.7 shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

7.6 In the event an Owner desires to separately schedule and dispatch any Unit, subject to the receipt of any necessary regulatory approvals or waivers, the Operating Committee shall establish and implement procedures and systems for separate scheduling and dispatch by each Owner, consistent with all of the requirements of any Person or regional transmission organization, such as PJM, supervising the collective transmission or generation facilities of the power region in which the Mitchell Plant is located that is charged with coordination of market transactions, system-wide transmission planning and network reliability and shall allocate costs and responsibilities in respect of any such separate dispatch (including with respect to Emission Allowances) consistent with such separate dispatch.

7.7 Emission Allowances. Prior to the earlier of any Buyout Transaction or December 31, 2028 (or earlier retirement of the Facility), to the extent that emission allowances issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Cross-State Air Pollution Rule 40 C.F.R. Part 97, and any amendments thereto (the "Emission Allowances"), are required for operation of the Mitchell Plant, each Owner will be entitled to receive for its own benefit 50% of any Emissions Allowances allocated to the Mitchell Plant. Each Owner will be responsible for acquiring any additional Emission Allowances needed to satisfy the Emission Allowances required because of such Owner's dispatch of energy from the Mitchell Plant. Additionally, prior to such time, each Owner will be responsible for acquiring the Emission Allowances required, to the extent necessary in addition to its share of the Emissions Allowances allocated to the Mitchell Plant, to satisfy 50% of the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al*., Civil Action Nos. C2-99-1182 and C2-99-1250 and *United States, et al. v. American Electric Power Service Corp., et al., Civil Action No. C2-05-360 and Ohio Citizen Action, et al. v. American Electric Power Service Corp.*, Civil Action No. C2-04-1098 dated December 10, 2007 as subsequently modified or amended, it being understood that the Owners may be subject to additional rights and obligations under any applicable agreement among the Owners (and/or their Affiliates) and American Electric Power Company, Inc. (and/or its Affiliates) pertaining to the allocation of emission limitations associated with the Mitchell Plant. As early as possible, but no later than three business days after the deadline for submitting final electronic data to the EPA for compliance purposes, the Operator shall notify each Owner of the number of annual or seasonal Emission Allowances that are needed to offset each Owner's share of emissions for the previous year or season. Each Owner shall supply its respective share of allowances, with a reasonable compliance margin as determined by the Operating Committee, by transferring the applicable allowances to the Mitchell Plant's Allowance Facility Account on or before 15 days prior to the remittance date. In the event that an Owner fails to surrender the required number of Emission Allowances in accordance with the prior paragraph, the other Owner shall have the option to purchase the required number of Emission Allowances, and the Owner that failed to surrender the required number of Emission Allowances shall reimburse the other Owner for any amounts it shall have incurred to make such purchases, with interest at the "Federal Funds Rate" (as published by the Board of Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for each Owner's share of the Emission Allowances required by the use of the Mitchell Plant and to correct any imbalance between the Emission Allowances supplied and the Emission Allowances used through the end of the preceding year by settlement or payment.

7.8 At least ninety (90) days before the start of each operating year, the Operator shall submit to the Operating Committee any proposed amendments to the Capital Budget and an annual operating budget for such operating year with respect to the Mitchell Plant, a proposed annual operating plan with respect to the Mitchell Plant for such operating year, and a forecast of operating and capital costs to be incurred during the next six-year period. The annual operating budget and amendments to the Capital Budget shall be presented on a month-by-month basis, and shall include an operating budget, a capital budget, and an estimate of the cost of any major repairs or improvements that are anticipated to occur during the relevant period with respect to the Mitchell Plant, and an itemized estimate of all projected fixed and variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual operating budget, final annual operating plan and any amendments to the Capital Budget. Once approved, the annual operating budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine. If an Early Retirement Event occurs, the members of the Operating Committee will meet and work in good faith to amend the Capital Budget to remove any future ELG Capital Expenditures and any other future capital expenditures no longer required, to the extent practicable and consistent with Applicable Law. The Capital Budget shall remain in effect throughout the Term, subject to such amendments as the Operating Committee may determine.

7.9 Notwithstanding anything in this Agreement to the contrary, (i) in the case of the O&M Agreement or any other agreement relating to the Mitchell Plant that is entered into jointly by or on behalf of the Owners, on one hand, with an Affiliate of an Owner (or with an Owner itself, as in the case of the O&M Agreement) on the other hand, the non-Affiliate Owner shall have the sole and exclusive right to exercise any and all affirmative or elective rights of the Owners, including remedies (including delivering notices of and pursuing or settling disputes or delivering notices of default or making and pursuing claims for indemnification) and any termination rights (including rights of termination for convenience, if any) thereunder (for the avoidance of doubt, without first obtaining the consent of the other Owner or the Operating Committee) and (ii) in the case the O&M Agreement is terminated pursuant to Section 8.2 thereof, KPCo shall have the sole and exclusive right to select and designate any successor "Operator" or replacement third-party Operator, in each case so long as such successor replacement is a "Qualified Replacement Operator" (as defined in the O&M Agreement); provided, however, that notice of any such action described in this Section 7.9 shall be sent to the other Owner at the time such action is taken if such other Owner is not the Operator. For purposes of this Agreement, "Affiliate" shall mean, with respect to any person or entity, any other person or entity that directly or indirectly, controls, is controlled by, or is under common control with such person or entity. As used in this definition, "control" (including, with its correlative meanings, "controlled by" and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a person or entity, whether through the ownership of securities or partnership or other ownership interests, by contract or otherwise.

## ARTICLE EIGHT
## EFFECTIVE DATE AND TERM

8.1 This Agreement shall be effective as of the Effective Date.

8.2 Subject to FERC approval or acceptance of any termination, if necessary, this Agreement shall remain in force until the earlier of (a) the date on which this Agreement is terminated by mutual agreement of the Owners or (b) the consummation of the Buyout Transaction contemplated by Section 9.6 (the period from the Effective Date through such date, the "Term").

## ARTICLE NINE
## TRANSFERS

9.1 Neither Owner may assign, transfer or otherwise dispose of its Ownership Interest, either in whole or part, whether by sale, lease, division, declaration or creation of a trust, by operation of law or otherwise ("Dispose" or a "Disposition") to any person or entity (the "Proposed Purchaser") without the prior written consent of the other Owner (the "Non-Offering Owner" and the Owner proposing the Disposition, the "Offering Owner"), which consent may be granted or withheld in the Non-Offering Owner's sole discretion; provided, that, the foregoing shall not restrict the Owners from pursuing or consummating the Buyout Transaction. Notwithstanding the foregoing, either Owner may Dispose of, all (but not less than all) of its Ownership Interest to a state regulated utility Affiliate, provided that (i) the Disposition shall not relieve the Offering Owner of its obligations under this Agreement, (ii) the Disposition shall be made in compliance with the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-99-1182 and C2-99-1250 and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360, and all amendments or modifications thereto, as in effect as of the date of the Disposition, (iii) the Proposed Purchaser shall agree to and assume, in respect of the Ownership Interest subject to the Disposition, the rights and obligations of the Offering Owner and its Affiliates under any applicable agreement with American Electric Power Company, Inc. (and/or its Affiliates) pertaining to the allocation of emission limitations associated with the Mitchell Plant, and (iv) in the event the Offering Owner (or any Affiliate thereof) shall be the Operator, the Proposed Purchaser shall also have been assigned, and agreed to have assumed, the rights and obligations of the Operator under this Agreement and the O&M Agreement as of the effective date of such Disposition; provided, that in the case of this clause (iv), a written consent from the Non-Offering Owner (which consent shall not be unreasonably withheld, conditioned or delayed) shall be obtained prior to such Disposition to the extent such Disposition results in the change of the Operator.

9.2 No Disposition shall be made unless all requisite regulatory and other approvals, consents and authorizations from all Governmental Authorities that are required to be obtained in connection with such Disposition have been obtained and as to which all conditions to the consummation of Disposition thereunder have been satisfied.

9.3 Subject to Section 9.6, all costs associated with any Disposition of an Ownership Interest by an Owner shall be borne solely by the Offering Owner, provided that the foregoing shall not limit the Offering Owner's right to seek reimbursement of any costs from the Proposed Purchaser in connection with any such Disposition.

9.4 Each Owner shall have the right to seek financing for all or a portion of such Owner's Ownership Interest and to provide general security for such financing of its Ownership Interest, including through the creation of any Encumbrance thereon (and the right of the beneficiary thereof to enforce thereon, but not to foreclose upon or transfer such Owner's Ownership Interest without the prior written consent of the other Owner), without the prior consent of the other Owner; provided that neither Owner may enter into any financing agreement or create any Encumbrance that would be reasonably likely to prohibit or otherwise restrict or condition the Buyout Transaction contemplated by Section 9.6. Each Owner further agrees to cooperate reasonably and in good faith, and to cause its Affiliates to so cooperate, with an Owner seeking financing in connection with such modifications and other rights and consents customary in transactions of such type, and not unreasonably to withhold its consent to such modifications as may be reasonably necessary or appropriate to allow such Owner to obtain such financing upon reasonably competitive terms, including obtaining consents to the assignment of such Owner's Ownership Interest in any of the Project Assets reasonably requested by such Owner's lender; provided that none of such proposed modifications shall (a) relieve the financing Owner of any of its obligations under this Agreement, the O&M Agreement or any other agreement related to the Mitchell Plant or any Project Asset, (b) decrease the economic benefits, or increase the costs, of the ownership and operation of the Mitchell Plant to the other Owner, (c) create any increased economic or legal risk to the other Owner in connection with the ownership and operation of the Mitchell Plant, (d) permit or allow any Encumbrances relating to any such financing to be placed upon any portion of or interest in the Project Assets other than the financing Owner's Ownership Interest, (e) permit partition of the Project Assets or any of them, including any partition upon a default by the financing Owner under any of the relevant financing documents or (f) prohibit or otherwise restrict or condition the Buyout Transaction as contemplated by Section 9.6.

9.5 Notwithstanding anything else herein to the contrary, no Disposition shall constitute a release of the Offering Owner from any liabilities to the Non-Offering Owner or the Operator arising from events occurring prior to or in connection with the Disposition, except as may be set forth expressly in the Mitchell Interest Purchase Agreement.

9.6 Buyout Transaction. Unless an Early Retirement Event occurs, the Owners shall enter into the Mitchell Interest Purchase Agreement pursuant to which KPCo shall sell, transfer and assign to WPCo, and WPCo shall purchase and assume from KPCo, all of KPCo's Ownership Interest (the "KPCo Interest") (including its interest in the underlying land, common facilities, barge unloading and gypsum conveyor facilities, and inventory and spare parts with respect to the Mitchell Plant), with the closing of such transaction to occur on December 31, 2028 (or such earlier date as may be mutually agreed by the Owners), subject to and in accordance with the provisions of this Section 9.6. The transactions contemplated by this Section 9.6 shall be referred to herein collectively as the "Buyout Transaction."

(a) Buyout Price. The purchase price for the KPCo Interest shall be (i) an amount mutually agreed by the Owners and approved by each of the WVPSC and the KPSC or, (ii) if no such amount is agreed by the Owners prior to June 30, 2027, an amount equal to (A) the Adjusted Fair Market Value of the KPCo Interest as of the closing date of the consummation of the Buyout Transaction, minus (B) the Decommissioning Costs Amount, plus (C) the Coal Inventory Adjustment (such aggregate amount, the "Buyout Price"). The Coal Inventory

Adjustment and the CapEx Adjustment shall be subject to a customary closing estimation and post-closing true-up mechanism to be set forth in the Mitchell Interest Purchase Agreement.

(b) Determination of Fair Market Value. Not later than June 30, 2026, the Owners shall commence discussions to determine mutually agreed amounts for the Fair Market Value for the KPCo Interest and the Decommissioning Costs Amount. Unless prior to June 30, 2027, (i) the Fair Market Value for the KPCo Interest (or other alternative Buyout Price) has been mutually agreed by the Owners pursuant to this Section 9.6 or (ii) an Early Retirement Event has occurred, then not later than July 31, 2027, each Owner shall deliver a written notice to the other Owner appointing a nationally or regionally recognized appraisal firm, which is not an Affiliate of either Owner, with experience valuing coal-fired electric generating facilities that are comparable in size and scope to the Mitchell Plant ("Appraiser"), the costs and expenses of which shall be borne by the Owner appointing such Appraiser. Each of the Appraisers selected by WPCo and KPCo, respectively, shall work together to select a third Appraiser within fifteen (15) days of selection of the first two Appraisers or, if such first two Appraisers fail to agree upon the appointment of a third Appraiser, such appointment shall be made by the American Arbitration Association, or any successor organization thereto. The costs and expenses of the third Appraiser shall be borne equally by the Owners. Each Owner shall cooperate with each Appraiser and timely provide information and access to the Mitchell Plant facilities (including, subject to any confidentiality restrictions, contracts and financial information) and personnel as may be reasonably needed to complete its appraisal. The Fair Market Value of the KPCo Interest shall be calculated by the Appraisers as of December 31, 2028 (or such earlier date of the anticipated closing of the Buyout Transaction), assuming that the Units would permanently cease operations as of December 31, 2040 (or such earlier anticipated date as may have been filed by WPCo with the WVPSC) but without taking into account any Decommissioning Costs or the value of the common coal pile. Each Appraiser shall prepare a detailed written appraisal of the Fair Market Value of the KPCo Interest within sixty (60) days after the selection of such third Appraiser and provide its valuation reports to each of the Owners. If the Fair Market Value determined by one of the three Appraisers deviates from the Fair Market Value determination of the middle Appraiser by more than twice the amount by which the Fair Market Value determination of the other Appraiser deviates from the Fair Market Value determination of the middle Appraiser, then the Fair Market Value determination of such Appraiser shall be excluded, the remaining two Fair Market Value determinations shall be averaged, and such average shall be the Fair Market Value, which shall be binding and conclusive on the Owners; otherwise the average of all three Fair Market Value determinations shall be the Fair Market Value, which shall be binding and conclusive on the Owners.

(c) Determination of Decommissioning Costs Amount. Unless prior to June 30, 2027, (i) the Decommissioning Costs Amount (or other alternative Buyout Price) has been mutually agreed by the Owners pursuant to this Section 9.6 or (ii) an Early Retirement Event has occurred, then not later than July 15, 2027, each Owner shall deliver a written notice to the other Owner appointing a nationally or regionally recognized engineering or consulting firm, which is not an Affiliate of either Owner, with experience decommissioning (or arranging decommissioning liability transfer arrangements for) coal-fired electric generating facilities that are comparable in size and scope to the Mitchell Plant ("Qualified Firm"), the costs and expenses of which shall be borne by the Owner appointing such Qualified Firm. Each of the Qualified Firms selected by

WPCo and KPCo, respectively, shall work together to select a third Qualified Firm within fifteen (15) days of selection of the first two Qualified Firms or, if such first two Qualified Firms fail to agree upon the appointment of a third Qualified Firm, such appointment shall be made by the American Arbitration Association, or any successor organization thereto. The costs and expenses of the third Qualified Firm shall be borne equally by the Owners. Each Owner shall cooperate with each Qualified Firm and timely provide information and access to the Mitchell Plant facilities (including, subject to any confidentiality restrictions, contracts and financial information) and personnel as may be reasonably needed to complete its determination. The Decommissioning Costs Amount shall be calculated by the Qualified Firms as of December 31, 2028 (or such earlier date of the anticipated closing of the Buyout Transaction), assuming for purposes of such determination (A) the Units would permanently cease operations, and Decommissioning of the Mitchell Plant would commence, as of such date, (B) the Mitchell Plant facilities would be dismantled and removed from the Mitchell Plant site, (C) the Mitchell Plant site would be remediated to a legally permissible industrial use standard, (D) all legal obligations and commitments to Governmental Authorities in connection with the Decommissioning of the Mitchell Plant would be appropriately addressed and satisfied, and (E) such additional or alternative assumptions as the Operating Committee may determine. Each Qualified Firm shall prepare a detailed written determination of the Decommissioning Costs Amount within ninety (90) days after the selection of such third Qualified Firm and provide its determination reports to each of the Owners. If the Decommissioning Costs Amount determined by one of the three Qualified Firms deviates from the Decommissioning Costs Amount determination of the middle Qualified Firm by more than twice the amount by which the Decommissioning Costs Amount determination of the other Qualified Firm deviates from the Decommissioning Costs Amount determination of the middle Qualified Firm, then the determination of such Qualified Firm shall be excluded, the remaining two Decommissioning Costs Amount determinations shall be averaged, and such average shall be the Decommissioning Costs Amount, which shall be binding and conclusive on the Owners; otherwise the average of all three Decommissioning Costs Amount determinations shall be the Decommissioning Costs Amount, which shall be binding and conclusive on the Owners.

(d) Buyout Procedures. Unless an Early Retirement Event has occurred, the Owners shall cooperate in good faith to negotiate and execute the Mitchell Interest Purchase Agreement not later than December 31, 2027, including completing any applicable disclosure schedules and exhibits, consistent with the terms and conditions described in this Section 9.6, so that any applicable regulatory or other approvals shall be timely obtained so as to allow the Buyout Transaction to be consummated on or prior to December 31, 2028.

## ARTICLE TEN
## DEFAULTS AND REMEDIES

10.1 An Owner shall be deemed to be in default hereunder upon the occurrence of any of the following events with respect to such Owner (each of the following events to be referred to as an "Event of Default," the Owner in default to be referred to as the "Defaulting Owner" and the Owner not in default to be referred to as the "Non-Defaulting Owner"):

(a) an Owner fails to make any payment required by it as and when due and payable in accordance with the terms of this Agreement, the O&M Agreement or any other agreement related to the Mitchell Plant or any Project Asset and such failure is not remedied within ten (10) days after receipt of written notice thereof by such Owner from the other Owner; provided, that any such notice shall include a statement of the amount the Defaulting Owner has failed to pay (a "Payment Default"); or

(b) an Owner fails to perform any material obligation (other than as described in Section 10.1(a)) imposed upon such Owner under this Agreement and such failure is not remedied within thirty (30) days after such Owner receives written notice thereof from the other; provided that, if such thirty (30) day period is not sufficient to enable the remedy or cure of such failure in performance, and such Owner shall have upon receipt of the initial notice promptly commenced and diligently continues thereafter to remedy such failure, then such Owner shall have a reasonable additional period of time (but in no event longer than an additional ninety (90) days from the end of the initial thirty (30) day cure period) to remedy or cure such failure; provided, however, that an Owner shall not be in default of its obligations hereunder to the extent such failure is caused by or is otherwise attributable to a breach by the other Owner of its obligations under this Agreement.

10.2 Without limiting the rights and remedies available to the Non-Defaulting Owner under Applicable Law, in the case of an Event of Default, the Non-Defaulting Owner shall have the right (but not the obligation) to (x) pay all or a portion of the amounts that were the subject of the Payment Default on behalf of the Defaulting Owner and (y) perform the obligation(s) which the Defaulting Owner has failed to perform on behalf of and at the expense of the Defaulting Owner (in any such case subject to all limits on liability benefiting the Defaulting Owner as set forth in this Agreement); and, if such payment is made (the portion as so paid or expended in connection with such performance, the "Paid Amount"), to:

(a) charge the Defaulting Owner interest with respect to the Paid Amount, from the day the payment was made by the Non-Defaulting Owner until it is paid in full by the Defaulting Owner to the Non-Defaulting Owner, at the rate equal to the prime rate as published from time to time in *The Wall Street Journal* (or any successor publication) plus five (5) percentage points per annum, calculated daily, regardless of whether the Non-Defaulting Owner has notified the Defaulting Owner in advance of its intention to charge interest with respect to such Paid Amount;

(b) set off against the Paid Amount any sums due or accruing to the Defaulting Owner by the Non-Defaulting Owner in accordance with this Agreement;

(c) maintain an action or actions for the Paid Amount and interest thereon on a continuing basis as the Paid Amount becomes payable but is not paid by the Defaulting Owner, as if the obligation to pay those amounts and the interest thereon was a liquidated demand due and payable on the date the amounts were due to be paid, without any right or resort of the Defaulting Owner to set-off or counter-claim against the Non-Defaulting Owner; and any obligation to pay interest under this Section 10.2 shall apply until the Payment Default is rectified or remedied; and

(d) at the Non-Defaulting Owner's option, (i) draw on any letter of credit posted by the Defaulting Owner pursuant to Section 4.3 in an amount equal to the Paid Amount, including all interest accrued thereon or (ii) receive one hundred percent (100%) of any revenues arising from or attributable to the sale of capacity, energy, ancillary services or other energy products from the Mitchell Plant that the Defaulting Owner would otherwise be entitled to receive in respect of its Assigned Capacity until the Non-Defaulting Owner receives an amount equal to the Paid Amount, including all interest accrued thereon, *plus* all costs of collection incurred in connection therewith, and the Owners shall cooperate with each other, the Operator, applicable Governmental Authorities (including in respect of securing any regulatory approvals) or other third parties (including lenders) as may be reasonably necessary to facilitate the Non-Defaulting Owner's right to be paid and receive the revenues attributable to the Defaulting Owner's Assigned Capacity until the applicable Paid Amount, including all interest accrued thereon and all costs of collection incurred in connection therewith has been paid to the Non-Defaulting Owner in full, including facilitating any appropriate changes in the applicable settlement accounts with respect to which market revenues are credited or paid by PJM or other applicable regional transmission organizations and executing any documents required to assign over such market revenues to the Non-Defaulting Owner.

## ARTICLE ELEVEN
## LIMITATION OF LIABILITY

11.1 Without limiting any other provision of this Agreement, each Owner's liability under this Agreement shall be limited to direct actual damages only. Such direct actual damages shall be the sole and exclusive remedy with respect to all claims arising under this Agreement and all other remedies or damages at law or in equity with respect to claims arising under this Agreement are waived, and unless expressly provided herein, no Owner shall be liable for consequential, punitive, incidental, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or in contract, under any indemnity provision or otherwise, with respect to claims arising under this Agreement. It is the intent of the Owners that the limitations herein imposed on remedies and the measure of damages be without regard to the cause or causes related thereto, including the negligence of any Owner, whether such negligence be sole, joint or concurrent, or active or passive. Notwithstanding anything herein to the contrary, the limitations set forth in this Section 11.1 shall not limit or preclude any indemnification obligations of an Owner pursuant to Article Ten of the O&M Agreement, including with respect to indemnification for third-party claims.

## ARTICLE TWELVE
## DISPUTE RESOLUTION

12.1 If either Owner believes that a dispute (including a Technical Dispute) has arisen as to the meaning or application of this Agreement, it shall submit a written description of the disputed matter to the Operating Committee, and shall provide a copy of that submission to the other Owner.

12.2 If the Operating Committee is unable to reach agreement on the resolution of a dispute not constituting a Technical Dispute submitted to the Operating Committee pursuant to Section 12.1 within thirty (30) days after the dispute is presented to it, the matter shall be referred to senior executive officers with the authority to resolve such dispute of each of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner may exercise any and all rights at law or equity at any time after the end of the thirty

(30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

12.3 If the Operating Committee is unable to reach agreement on the resolution of a Technical Dispute submitted to the Operating Committee within ten (10) business days after such Technical Dispute is presented to it, then either Owner may refer such Technical Dispute to a Technical Expert. Within ten (10) business days following receipt of an Owner's notice referring a Technical Dispute to a Technical Expert, the Operating Representatives shall confer to agree upon a Technical Expert to hear the Technical Dispute. If the Owners are unable to agree upon the appointment of a Technical Expert, then at the end of such ten (10) business day period each Owner shall, within five (5) business days, notify the other Owner in writing of its designation of a proposed Technical Expert. The two proposed Technical Experts shall, within five (5) business days, select a Technical Expert (who may be one of the two Technical Experts designated by the Owners or another Technical Expert) and such Technical Expert shall hear the Technical Dispute. Each Owner shall be required to put forth and endorse one proposal, budget or solution, as the case may be, as its proposed resolution to the Technical Dispute, based on an agreed statement of the nature of the Technical Dispute and agreed facts surrounding such Technical Dispute. Each Owner's proposal, budget or solution shall be delivered to the Technical Expert and the other Owner no later than twenty (20) business days after the date of the notice of the Owner submitting the Technical Dispute to the Technical Expert. The Technical Expert shall be guided by consideration of (a) this Agreement, (b) all other agreements between the Owners relating to the Mitchell Plant, including the O&M Agreement and (c) Prudent Operation and Maintenance Practices (as defined in the O&M Agreement), and be required to select one of the proposals, budgets or solutions, as the case may be, and shall not be able to select any other proposal, budget or solution, except to the extent mutually agreed by the Owners. The Technical Expert shall render a decision resolving the matter within forty-five (45) days of the date of the notice of the Owner submitting such matter. The Technical Expert shall not award to either Owner any relief greater than that initially sought by such Owner. The decision of the Technical Expert shall be final and binding upon the Owners and not subject to appeal or review. The Owners shall bear equally all costs and expenses of the Technical Expert procedure and the Technical Expert shall not have the authority to award costs or attorneys' fees to either Owner. The Technical Expert shall act as an expert and not as an arbitrator and the provisions of the Federal Arbitration Act and the laws relating to arbitration shall not apply to the Technical Expert or the Technical Expert's determination or the procedure by which a determination is reached. Except as provided in Section 7.2(a), the Technical Expert's decision shall not in any event result in deviations from the agreed allocations of costs between the Owners as set forth in this Agreement.

12.4 Except as provided in this Article Twelve, the existence, contents, or results of any settlement negotiations or the results thereof under this Article Twelve may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any Governmental Authority having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with any proceeding under pledge of confidentiality.

12.5 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through an action at law or equity. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. §§ 791a et seq., as amended from time to time, and any proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of FERC proceedings. To the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed at law or equity to secure such a remedy, subject to any FERC decisions, findings, or orders.

12.6 If an Owner (the "Contesting Owner") contests in good faith any amount paid pursuant to the terms of this Agreement following receipt of the written notice of the other Owner delivered pursuant to Section 10.1(a), and any portion of such amount is determined or resolved (including pursuant to the dispute resolution procedures of this Article Twelve) to be in excess of the actual amount due pursuant to the terms of this Agreement, then the Contesting Owner may charge the other Owner interest with respect to such excess amount from the day the payment was made until it is repaid to the Contesting Owner, at the rate equal to the prime rate as published from time to time in *The Wall Street Journal* (or any successor publication) plus five (5) percentage points per annum, calculated daily, regardless of whether the Contesting Owner has notified the other Owner in advance of its intention to charge interest with respect to such excess amount, and the other Owner shall make payment in full in respect of such excess amount and interest within thirty (30) days of written demand therefor.

## ARTICLE THIRTEEN
## GENERAL

13.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and permitted assigns, but this Agreement may not be assigned by any signatory without the written consent of the other parties hereto or as permitted by Article Nine hereof.

13.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

13.3 The interpretation and performance of this Agreement is governed by and shall be construed in accordance with the laws of the State of New York, exclusive of the conflicts of law provisions thereof that would require the application of the laws of a different jurisdiction. Each Owner hereby agrees that any Action arising out of or relating to this Agreement brought by an Owner (or any of their respective successors or assigns) shall be brought and determined in any state or federal court sitting in the State of New York, within the Borough of Manhattan, City of New York, and the Owners hereby irrevocably submit to the exclusive jurisdiction of the aforesaid courts for themselves and with respect to their property, generally and unconditionally, with regard to any such Action arising out of or relating to this Agreement and the transactions contemplated hereby, and the appellate courts from any thereof in connection with any action arising out of or relating to this Agreement or any other agreement related to the Mitchell Plant or any Project Asset and the transactions contemplated hereby, and consents that any such action may be brought in such courts and waives any objection it may now or hereafter have to the venue of any such action in any such court or that such action was brought in an inconvenient court. EACH OWNER HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ALL RIGHTS TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING TO THIS AGREEMENT, THE O&M AGREEMENT, OR ANY OTHER AGREEMENT RELATED TO THE MITCHELL PLANT OR ANY PROJECT ASSET.

13.4 This Agreement supersedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories hereto or their representatives with respect to operation of the Mitchell Plant, including the Original Operating Agreement. Notwithstanding the foregoing, the amendment and restatement of the Original Operating Agreement effected hereby shall not relieve any party thereto of any undischarged obligation or liability of such party in respect of the period prior to the Effective Date under the Original Operating Agreement. This Agreement, together with the O&M Agreement (and any replacements thereof), constitutes the entire agreement of the signatories hereto with respect to the operation of the Mitchell Plant and the ownership thereof. The signatories hereto hereby agree that this Agreement shall amend the Original Operating Agreement to irrevocably remove AEPSC as a party thereto and, on and after the Effective Date, AEPSC shall no longer be a party thereto or hereto or entitled to rights, or subject to obligations, as a party to this Agreement; <u>provided, however</u>, that Operator shall be permitted to delegate any of its rights, duties and obligations under this Agreement and the O&M Agreement to AEPSC without the consent of KPCo, but without relieving Operator of any of its obligations hereunder.

13.5 No amendments or modifications of this Agreement are valid unless in writing and signed by duly authorized representatives of the Owners.

13.6 Each Owner shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
[______]____________________________
[______]____________________________

Attn: ______________________________

Phone: [______]_____________________

Email: [______]______________________

WHEELING POWER COMPANY
[______]____________________________

[______]
___________________________________
Attn: ______________________________
Phone: [______]____________________
Email: [______]_____________________

All notices shall be deemed to have been given (a) when personally delivered, (b) when transmitted (except if not a Business Day then the next Business Day) via electronic mail (provided that no error message or other notification of non-delivery is generated with respect to the intended recipient), (c) the day following the day (except if not a Business Day then the next Business Day) on which the same has been delivered prepaid to a reputable national overnight air courier service or (d) the third Business Day following the day on which the same is sent by certified or registered mail, postage prepaid, in each case to the respective parties hereto at the address set forth below, or at such other address as such Owner may specify by written notice to the other Owner (or at such other address for an Owner as shall be specified in a notice given in accordance with this Section 13.6). Each Owner may, by written notice to the other Owner, change the representative or the address to which such notices are to be sent.

13.7 This Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument, but all of such counterparts shall constitute for all purposes one agreement. Any signature hereto delivered by a party hereto by facsimile or other electronic transmission shall be deemed an original signature hereto.

13.8 Except as otherwise specifically provided, all fees, costs and expenses incurred by the parties hereto in negotiating this Agreement shall be paid by the party incurring the same, including legal and accounting fees, costs and expenses.

13.9 Any of the terms, covenants, or conditions hereof may be waived only by a written instrument executed by or on behalf of the Owners waiving compliance. No course of dealing on the part of any Owners, or its respective officers, employees, agents, accountants, attorneys, investment bankers, consultants or other authorized representatives, nor any failure by an Owner to exercise any of its rights under this Agreement shall operate as a waiver thereof or affect in any way the right of such Owner at a later time to enforce the performance of such provision. No waiver by any Owner of any condition, or any breach of any term or covenant contained in this Agreement, in any one or more instances, shall be deemed to be or construed as a further or continuing waiver of any such condition or breach or a waiver of any other condition or of any breach of any other term or covenant. The rights of the Owners under this Agreement shall be cumulative, and the exercise or partial exercise of any such right shall not preclude the exercise of any other right.

13.10 This Agreement shall be binding upon and inure to the benefit of the Owners and their respective successors and permitted assigns.

13.11 No Owner will issue, or permit any of its Affiliates, its or its Affiliate's directors, officers, employees, consultants, agents or other representatives to issue, any press releases or otherwise make, or cause any of its Affiliates, its or its Affiliate's directors, officers, employees, consultants, agents or other representatives to make, any public statements or other public disclosures with respect to this Agreement, or the transactions contemplated hereby without the prior written consent of the other Owner; provided, however, that the foregoing requirement to obtain prior written consent shall not apply where such release, statement or disclosure is deemed in good faith by the releasing or disclosing Owner to be required by Applicable Law or under the rules and regulations of a recognized stock exchange on which shares of such Owner (or any of its Affiliates) are listed, so long as prior to making any such release, statement or disclosure and to the extent legally permitted, the releasing or disclosing Owner shall provide prompt notice to the other Owner, consult the other Owner as to the form, contents and timing of such release or disclosure and, when available, provide a copy of such release, statement or disclosure containing such information to the other Owner.

13.12 If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Owners shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Owners as closely as possible in an acceptable manner to the end that the transactions contemplated hereby are fulfilled to the extent possible.

13.13 Each Owner acknowledges that it shall be inadequate or impossible, or both, to measure in money the damage to the Members if any of them or any transferee or any legal representative of any Owner fails to comply with any of the restrictions or obligations imposed by Article Nine that every such restriction and obligation is material, and that in the event of any such failure, the Owners shall not have an adequate remedy at law or in damages. Therefore, each Owner consents to the issuance of an injunction or the enforcement of other equitable remedies against such Owner at the suit of an aggrieved party without the posting of any bond or other security, to compel specific performance of all of the terms of Article Nine and to prevent any Disposition in contravention of any terms of Article Nine, and waives any defenses thereto, including the defenses of: (i) failure of consideration, (ii) breach of any other provision of this Agreement and (iii) availability of relief in monetary damages.

## ARTICLE FOURTEEN
## DEFINITIONS

For all purposes of this Agreement (including the preceding sections and recitals), unless otherwise required by the context in which any defined term appears or otherwise defined in the body of this Agreement, capitalized terms have the meanings specified in this Article Fourteen. In this Agreement, unless expressly stated otherwise: (a) reference to any agreement (including this Agreement), document or instrument means such agreement, document or instrument as has been, or may be, amended, supplemented or otherwise modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (b) reference to any

Applicable Law means such Applicable Law as has been, or may be, amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including rules and regulations, promulgated thereunder; (c) the singular includes the plural, as the context requires; (d) the terms "includes" and "including" mean "including, but not limited to"; (e) "Day" (regardless of capitalization) shall mean a calendar day, unless specifically designated as a Business Day or business day; (f) "Month" (regardless of capitalization) shall mean a calendar month; (vii) references to articles, sections and appendices mean the articles and sections of, and appendices to, this Agreement.

"Adjusted Fair Market Value" means any positive amount (if any, and zero otherwise) equal to (A) the Fair Market Value, minus (B) the CapEx Adjustment.

"AEPSC" shall have the meaning given to such term in the Preamble.

"Agreement" shall have the meaning given to such term in the Preamble.

"Applicable Law" shall mean all laws (including common law), statutes, codes, acts, treaties, ordinances, orders, judgments, writs, decrees, injunctions, rules, regulations, governmental approvals, permits, directives, and requirements of all Governmental Authorities (including with respect to the environment) having jurisdiction over an Owner, any other person or entity (as to that person or entity), this Agreement, any Project Asset or the Mitchell Plant, as applicable.

"Appraiser" shall have the meaning given to such term in Section 9.6(b).

"Assigned Capacity" shall have the meaning given to such term in Section 2.3.

"Buyout Price" shall have the meaning given to such term in Section 9.6(a).

"Buyout Transaction" shall have the meaning given to such term in Section 9.6.

"CapEx Adjustment" shall mean (a) 50% of any capital expenditures (or portion thereof), including ELG Capital Expenditures, to the extent funded by WPCo in an amount in excess of 50% of the total amount thereof on or prior to December 31, 2028, plus (b) an amount equal to the WACC for the amounts included in clause (a), applied to all of such amounts using the then-applicable WACC from the dates of funding through the closing date of the consummation of the Buyout Transaction.

"Capital Budget" shall have the meaning given to such term in Section 1.7.

"CertainTeed Contract" shall mean that certain Supply Agreement dated March 11, 2005, by and between CertainTeed Gypsum West Virginia, Inc. (formerly BPB West Virginia Inc.) and KPCo (as assignee of Ohio Power Company), as amended by Amendment No. 2010-1 dated August 2, 2010, as further amended by Amendment No. 2012-1 dated February 20, 2012 and as further amended by Amendment No. 2013-1 dated June 5, 2013, as may be amended, amended and restated, supplemented or modified from time to time, and as may be assigned to Operator or an Affiliate of Operator.

"CCR Capital Expenditures" shall mean all capital expenditures associated with implementation of the CCR Upgrades.

"CCR Rule" means the Coal Combustion Residuals Rule, 40 CFR Part 257 (April 17, 2015, as amended), and any regulations thereunder promulgated by the USEPA or the State of West Virginia.

"CCR Upgrades" shall mean any improvements or upgrades to the Mitchell Plant to enable KPCo and WPCo to comply with the CCR Rule.

"Coal Inventory Adjustment" shall mean the weighted-average cost of KPCo's investment in the common coal pile for the Mitchell Plant.

"Control" shall have the meaning given to such term in Section 7.10.

"Credit Rating" means with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt or deposit obligations (not supported by third party credit enhancements) by S&P or Moody's. If no rating is assigned to such entity's unsecured, senior long-term debt or deposit obligations by S&P or Moody's, then "Credit Rating" means the general corporate credit rating or long-term issuer rating assigned to such entity by S&P or Moody's. If an entity is rated by both S&P and Moody's and the ratings are at different levels, then "Credit Rating" means the lowest such rating.

"Decommission" or "Decommissioning" shall mean the retirement, dismantlement and permanent removal of the Units and other property, plant, and equipment comprising the Mitchell Plant, including any common facilities associated with each Unit that are to be permanently removed from service, the restoration of the Mitchell Plant site and the removal or remediation of any hazardous materials or other contaminated equipment, materials, coal ash or wastes associated therewith, in a manner that meets the requirements of Applicable Law.

"Decommissioning Costs" shall mean all costs and obligations expended or incurred in the performance of all work reasonably necessary or undertaken to Decommission the Mitchell Plant, including work associated with the preparation and implementation of Decommissioning plans and the preparation, submittal and prosecution of all necessary applications with Governmental Authorities as required to Decommission the Mitchell Plant in accordance with Applicable Law.

"Decommissioning Costs Amount" shall mean an amount equal to 50% of all Decommissioning Costs, as determined by and adjusted in accordance with the procedures and calculation criteria and factors set forth in the Section 9.6(c).

"Defaulting Owner" shall have the meaning given to such term in Section 10.1.

"Depreciable Life" means, with respect to a capital item, the shorter of (a) the reasonably expected depreciable life (in months) of such capital item and (b) the number of months between the anticipated in-service date of such capital item and December 31, 2040 (or such earlier anticipated date of the permanent cessation of operations of the Units filed with the WVPSC).

"Dispose" or "Disposition" shall have the meaning given to such term in Section 9.1.

"Early Retirement Event" shall mean the delivery of a written notice by WPCo to KPCo irrevocably committing to permanently cease operations of the Mitchell Plant effective on or, with KPCo consent, prior to December 31, 2028, which notice shall be consistent with WPCo's current filings at such time with the WVPSC in respect of the Mitchell Plant.

"Effective Date" shall have the meaning given to such term in the Preamble.

"ELG Capital Expenditures" shall mean all capital expenditures associated with implementation of the ELG Upgrades.

"ELG Rule" shall mean the Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650 (Oct. 13, 2020), and any regulations thereunder promulgated by the USEPA or the State of West Virginia.

"ELG Upgrades" shall mean any improvements or upgrades to the Mitchell Plant to enable WPCo to comply with the ELG Rule.

"Emission Allowances" shall have the meaning given to such term in Section 7.7.

"Encumbrance" shall mean with respect to any property or asset (a) any mortgage, deed of trust, charge, lien, pledge, hypothecation, title retention arrangement or other security interest, as or in effect as security for the payment of a monetary obligation or the observance of any other obligation; (b) any easement, servitude, restrictive covenant, equity or interest in the nature of an encumbrance, garnishee order, writ of execution, right of set-off, lease, license to use or occupy, assignment of income or monetary claim, whether or not filed, recorded or otherwise perfected under Applicable Law; and (c) any agreement to create any of the foregoing or allow any of the foregoing to exist.

"Event of Default" shall have the meaning given to such term in Section 10.1.

"Fair Market Value" shall mean, with respect to the KPCo Interest as of any date, an amount (which may be a positive or a negative number) equal to 50% of the cash price obtainable in an arm's-length sale of the entirety of the Mitchell Plant between an informed and willing buyer and seller, in each case under no compulsion to buy or sell, as the case may be, as determined by and adjusted in accordance with the procedures and valuation criteria and factors set forth in Section 9.6(b).

"FERC" shall have the meaning given to such term in Section 5.1.

"FERC Accounting Requirements" means the accounting requirements of FERC, including with respect to the Uniform System of Accounts, established by FERC under the FPA.

"FPA" means the Federal Power Act.

"Governmental Authority" means any federal, national, regional, state, municipal or local government authority, tribunal, court, agency, body, board or instrumentality, or any regulatory, administrative or other department, commission, bureau or agency, taxing authority or power, or any political or other subdivision, department or branch of the foregoing, including any independent system operator, regional transmission organization or electric reliability organization.

"HSR Act" shall mean the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

"KPCo" shall have the meaning given to such term in the Preamble.

"KPCo Interest" shall have the meaning given to such term in Section 9.6.

"KPSC" shall mean the Kentucky Public Service Commission.

"Mitchell Interest Purchase Agreement" shall mean an asset purchase agreement between KPCo and WPCo to implement the Buyout Transaction at the Buyout Price, consistent with Section 9.6 and on a non-recourse basis to KPCo, subject to an indemnity expiring on December 31, 2050 by KPCo for the benefit of WPCo, with a cap of $15 million, for unknown contingent liabilities with respect to items arising from KPCo's 50% Ownership Interest prior to the date of the closing of the Buyout Transaction and not estimated or otherwise factored in the calculation of Fair Market Value or the Decommissioning Costs Amount.

"Mitchell Plant" shall mean the Mitchell Power Generation Facility, which consists of the Units and associated plant, equipment, real estate and other related facilities, located in Moundsville, West Virginia, but excluding the real property and operation known as the Conner Run Fly Ash Impoundment and Dam.

"Moody's" shall have the meaning given to such term in Section 4.3.

"Non-Defaulting Owner" shall have the meaning given to such term in Section 10.1.

"Non-Offering Owner" shall have the meaning given to such term in Section 9.1.

"O&M Agreement" shall have the meaning given to such term in the Recitals.

"Offering Owner" shall have the meaning given to such term in Section 9.1.

"Operating Committee" shall have the meaning given to such term in Section 7.1.

"Operating Representative" shall have the meaning given to such term in Section 7.1.

"Operator" shall have the meaning given to such term in the Recitals.

"Original Operating Agreement" shall have the meaning given to such term in the Recitals.

"Owner" or "Owners" shall have the meaning given to such term in the Preamble.

"Ownership Interest" shall have the meaning given to such term in the Recitals.

"Paid Amount" shall have the meaning given to such term in Section 10.2.

"Payment Default" shall have the meaning given to such term in Section 10.1(a).

"Project Assets" shall have the meaning given to such term in Section 1.1.

"Proposed Purchaser" shall have the meaning given to such term in Section 9.1.

"Qualified Firm" shall have the meaning given to such term in Section 9.6(c).

"Ratings Requirement" shall mean a Credit Rating for such Owner (or if such Owner has provided a guaranty issued by an Affiliate to satisfy its obligations under this Section 4.3, such Owner's Affiliate guarantor) of at least "BBB-" by S&P or at least Baa3 by Moody's, and if such Credit Rating is "BBB-" by S&P or "Baa3" by Moody's then such Credit Rating must not be on negative credit watch by S&P or Moody's.

"S&P" shall have the meaning given to such term in Section 4.3.

"Tax Code" shall have the meaning given to such term in Section 6.6.

"Technical Dispute" shall mean any dispute which this Agreement expressly provides shall be a Technical Dispute.

"Technical Expert" shall mean any individual selected in accordance with the procedure specified in Section 12.3 and who (a) has significant professional qualifications and practical experience in the subject matter of the Technical Dispute, (b) has no interest, financial or otherwise, or duty which conflicts or may conflict with such individual's functions as a Technical Expert (such individual being required to fully disclose any such interest or duty prior to any appointment) and (c) is not currently and has not been (i) during the five (5) years prior to the date of appointment, an employee of any of the Owners or any of their Affiliates and (ii) during the three (3) years prior to the date of appointment, a contractor or consultant of either of the Owners or any of their Affiliates, unless otherwise mutually agreed by the Owners.

"Term" shall have the meaning given to such term in Section 8.2.

"Total Net Capability" shall have the meaning given to such term in Section 2.1.

"Total Net Generation" shall have the meaning given to such term in Section 2.2.

"Unit" shall have the meaning given to such term in the Recitals.

"USEPA" shall have the meaning given to such term in Section 7.7.

"WACC" shall mean, as of any date, WPCo's then-applicable WVPSC-authorized weighted average cost of capital, compounded semiannually (consistent with the compounding of Allowance for Funds Used During Construction (AFUDC)).

"WPCo" shall have the meaning given to such term in the Preamble.

"WVPSC" shall mean the Public Service Commission of West Virginia.

[*Signature pages follow.*]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: ______________________________________

Title:

WHEELING POWER COMPANY

By: ______________________________________
Title:

Solely with respect to Section 13.4:

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: ______________________________________
Title:

**<u>Exhibit A</u>**

**<u>Capital Budget, Initial Budgets and Forecast</u>**

[To Be Attached as of the Effective Date.]

## Exhibit B

## Form of Monthly Sample Report

[To Be Attached as of the Effective Date.]

# MITCHELL OPERATING COMMITTEE

## MINUTES

## November 9, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on November 9, 2021, at 5:00 p.m. (Eastern).

**Operating Representatives Present:**

(1) Chris Beam, President and Chief Operating Officer, Wheeling Power Company; (2) Brett Mattison, President and Chief Operating Officer, Kentucky Power Company; and (3) Tim Kerns, VP Generating Assets, Fossil & Hydro Generation, American Electric Power Service Corporation.

Constituting all of the Operating Representatives. Also present were John Crespo, Christen Blend, Jim Bacha, Randy Ryan, Stephan Haynes, Matt Satterwhite, Mike Zwick, Brian Sherrick and Bill Mast.

Mr. Crespo acted as Secretary of the meeting of the Operating Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives approved the Agenda for the meeting, attached.

Mr. Ryan, AEP legal counsel, presented further information about the proposed Mitchell Operation and Maintenance Agreement and the proposed Mitchell Ownership Agreement requested by the Operating Representatives during the meeting of the Mitchell Operating Committee held on November 2, 2021. The Operating Representatives and legal counsel engaged in further discussions regarding the terms and condition of the agreements.

Mr. Sherrick, on behalf of the Agent, presented information regarding the selection of an independent engineer as a technical expert to provide information to the Operating Committee to identify and separate ELG and CCR project costs. Mr. Sherrick presented a non-final summary of the Agent's evaluation of the firms, attached to these Minutes. Mr. Sherrick noted that the Agent was still completing its evaluation. The Operating Representatives, Mr. Sherrick and other meeting attendees engaged in additional discussions regarding the selection of the independent engineer. Mr. Sherrick stated that the Agent would provide a final recommendation to the Operating Representatives for their approval when the Agent's evaluation was completed.

Mr. Sherrick further provided information to the Operating Representatives concerning the engineering and design contracts that would need to be awarded by the Mitchell Plant operator to various vendors so that the ELG and CCR work could be completed. Mr. Sherrick further noted that any expenditures could be reallocated between Kentucky Power and Wheeling Power based on the study of the independent engineer and the terms of the proposed Mitchell Ownership Agreement, when full executed following necessary regulatory approvals.

There being no further business, the Operating Committee meeting was adjourned.

John Crespo

Secretary

## John C Crespo

**From:** Brian D Sherrick
**Sent:** Tuesday, November 9, 2021 12:57 PM
**To:** John C Crespo
**Cc:** Bill Mast; Raja Sundararajan; Matthew J Satterwhite; Tim Kerns
**Subject:** WV Units - CCR/ELG Engineering Study Update (11/9/21)

John,

Here is the status update for finding an independent engineering consultant to evaluate the WV units CCR/ELG cost allocations in preparation for the Mitchell Operating Agreement meeting this afternoon:

==================================================================================================================

We have engaged several A/E firms with the necessary technical, accounting, and regulatory experience to provide direction on appropriate cost allocation of the CCR vs ELG scope of works at the WV facilities. The requests were made to firms based on our experience and recommendations from the project equipment suppliers and peer utilities. What we found is a very small subset of A/Es that possess the capabilities to perform this analysis and that the same A/Es (Worley, Burns & McDonnell, and S&L) were recommended by several sources. Note: Worley is the A/E for the projects.

A list of the firms and proposal status is outlined in the matrix below. We are still awaiting a proposal from one firm, but indications are that we would select either Burns & McDonnell or Black & Veatch to perform this study. The work will be done under a T&M contract, so there is an assumption that the cost gap will narrow between those two firms upon execution of a contract.

WV Plants CCR/ELG Engineering Cost Study
rev 11-9-21

Privileged and confidential

| Consultant | Technology Experience | CCR/ELG Rule Familiarity | Reg./Test Experience | Submitted Proposal | Proposed Schedule | Proposed Cost ($K) | Evaluation |
|---|---|---|---|---|---|---|---|
| Burns & McDonnell | **X** | **X** | **X** | **X** | 10 wks | $148 | Provided conservative proposal. Add'l cost for operational cost evaluation. A/E for Flint Creek CCR/ELG Project. |
| TRC | **X*** | | | **-** | - | - | *No ELG Exp. No Reg. Exp. No Proposal |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Power Engineers | **X** | **X** | **X** | **-** | - | - | Firm is capable, no resource availability until Q1 '22 |
| Golder Associates | | | | | | | RFP made 10-29-21 (DUKE reference), proposal due 11/10. |
| Black & Veatch | **X** | **X** | **X** | **X** | 10 wks | $44 | Add'l cost for operational cost evaluation. A/E for Southern Plant Barry CCR/ELG Project.  AEP T&D uses; past AEP Gen experience. |
| HDR | **X*** | | | **-** | - | - | *No ELG Exp. No Reg. Exp. No RFP Issued |
| Keiwit | **X** | **X** | **X** | **-** | - | - | Non-responsive |
| | | | | | | | |

Our evaluation and final recommendation will be made by 11/12, but wanted to update you on our progress and see if there are any concerns with using a firm very experienced with AEP and not completely independent given the sparsity of firms capable of completing the task.

Thanks,
Bill Mast

# MITCHELL OPERATING COMMITTEE

## AGENDA

## November 9, 2021

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") will be held on November 9, 2021, at 5:00 p.m. (Eastern).

**Invitees**: Operating Representatives: Brett Mattison (Kentucky Power), Chris Beam (Wheeling Power), Tim Kerns (Agent), Mike Zwick (Agent – Alternate)

Other Invitees: John Crespo (Secretary), Christen Blend, Jim Bacha, Randy Ryan, Mathew Satterwhite, Raja Sundararajan, Randy Ryan, Stephan Haynes, Brian Sherrick, Bill Mast

**1. Call to Order**

A. Roll Call for Quorum

B. Review of Agenda

**2. Review of Proposed Mitchell Operations and Maintenance Agreement and Proposed Mitchell Ownership Agreement** – Legal Counsel

A. Review and discussion of revised terms of draft Mitchell Operations and Maintenance Agreement and draft Mitchell Ownership Agreement.

B Discussion of potential resolutions related to the proposed agreements.

**2. Update on Selection of Independent Engineer for CCR/ELG Cost Segregation** – Brian Sherrick

**3. Briefing on Future Expenditures Related to CCR/ELG Engineering and Design** – Brian Sherrick

**3. Other Business**

**4. Adjournment**

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on April 12, 2022, at 1:00 p.m. EDT.

**Operating Representatives Present:**

- Chris Beam, President and Chief Operating Officer, Wheeling Power Company (WPCo)
- Brett Mattison, President and Chief Operating Officer, Kentucky Power Company (KPCo)
- Tim Kerns, VP Generating Assets – KPCO and I&M, American Electric Power Service Corporation (AEPSC)

Constituting all of the Operating Committee representatives. Also present were:

- John Crespo – Deputy General Counsel, AEPSC
- Mike Zwick – VP Generating Assets - APCo, AEPSC
- Brian West – VP Regulatory and Finance, KPCo
- Brian Sherrick – Project Solutions Managing Director, AEPSC
- Bill Mast – Project Solutions Director, AEPSC

Bill Mast provided an overview presentation for the Committee to review the results of the Burns and McDonnell (independent engineer retained by this Operating Committee to evaluate the allocation of capital and O&M costs of the CCR and ELG compliance projects) CCR/ELG Cost Allocation Summary. The Operating Committee will review the Mitchell Plant CCR/ELG Cost Allocation Summary report and respond by email to accept, modify, or amend the document by 4/28/22.

**Action Item:** Voting members of the Operating Committee to respond by email by 4/28/22 whether to accept, modify or amend the Burns and McDonnell letter regarding ELG / CCR cost allocations.

**WRITTEN CONSENT ACTION**

**OF THE MITCHELL OPERATING COMMITTEE**

**September 1, 2022**

The undersigned, being all of the Owners' Operating Representatives of the Operating Committee (the "Committee") of the Mitchell Plant Operating Agreement (the "Agreement"), do hereby consent to the adoption of the following resolutions, which resolutions shall be deemed to be adopted as of the date hereof ("Effective Date") and to have the same force and effect as if such resolutions had been adopted at a meeting duly called therefor:

**1. Waiver of Notice.**

**RESOLVED**, that any and all notice to take any action in adopting the following resolutions be, and it hereby is, waived by the undersigned.

**2. Approval of Resolutions To Implement the Agreement**

**WHEREAS**, Wheeling Power Company ("Wheeling Power") and Kentucky Power Company ("Kentucky Power") recognize that the Public Service Commission of West Virginia ("WVPSC") and the Kentucky Public Service Commission ("KPSC") approved different investments in response to federal environmental rules at the Mitchell Plant and different approaches to operating and owning the Mitchell Plant after December 31, 2028;

**WHEREAS**, the WVPSC in its orders authorized Wheeling Power to make any improvements or upgrades to the Mitchell Plant to enable compliance with the Effluent Limitations Guidelines ("ELG Rule"), and agreed exclusively to fund all of the capital expenditures associated with implementation of the ELG Rule ("ELG Upgrades"), and to make other necessary improvements or upgrades to the Mitchell Plant, to preserve the option to operate the plant past 2028;

**WHEREAS**, the KPSC in its orders authorized Kentucky Power to make only the improvements and upgrades to the Mitchell Plant to enable compliance with the Coal Combustion Residuals Rule ("CCR Rule"), and agreed to fund only its ownership share of the capital expenditures associated with the CCR Rule ("CCR Upgrades"), but not the ELG Rule, and acknowledged that because the ELG Upgrades are needed to operate the Mitchell Plant after 2028, approving the CCR and not the ELG Upgrades results in Kentucky Power being permitted only to operate the Mitchell Plant until the end of 2028;

**WHEREAS**, on November 19, 2021, each Owner filed with its Commission a proposed Mitchell Plant Operations and Maintenance Agreement and a proposed Mitchell Plant Ownership Agreement ("Proposed Mitchell Agreements") to replace the Agreement to facilitate compliance with the KPSC's and WVPSC's respective orders regarding compliance with the CCR and ELG Rules at the Mitchell Plant;

**WHEREAS**, the Committee believed that replacement of the Agreement with the New Mitchell Agreements at the soonest practical date was advisable and in the best interests of

Kentucky Power Company, Wheeling Power Company, and their respective customers;

**WHEREAS**, the KPSC and WVPSC issued orders adopting versions of the Mitchell Agreements on May 3, 2022 and July 1, 2022, respectively, that differ in material respects, such that the Owners are unable to enter into new agreements at the current time;

**WHEREAS**, the Agreement remains in full force and effect in accordance with its terms pending future negotiation of longer term arrangements by the Owners that replace the Agreement, subject to state and other applicable regulatory approvals;

**WHEREAS**, in light of the foregoing developments, the Operating Committee believes it is now in the best interests of the Mitchell Plant and their respective customers to continue operating under the Agreement in the short term to accomplish the operational objectives necessitated by the KPSC and WVPSC in their orders and prevent any delays in constructing the ELG Upgrades, which could have a negative effect on future plant outages and unit availability;

**WHEREAS**, the Committee must establish certain operating principles pursuant to its authority under the Agreement to appoint Wheeling Power as the operator of the Mitchell Plant, to enable the ELG Upgrades to be performed by Wheeling Power, and to adopt the procedures necessary to properly allocate costs between the two Owners such that Wheeling Power will pay for all of the costs of the ELG Upgrades, in accordance with the authority of the Committee under the Agreement;

**WHEREAS**, the Committee must also appropriately allocate costs between the two Owners such that Wheeling Power will pay for the cost of capital investments to the extent they have a depreciable life after December 31, 2028;

**WHEREAS**, the Committee is vested with certain enumerated rights and duties under the Agreement, as well as other duties as agreed by the Owners (Section 7.2(j));

**WHEREAS**, the rights and responsibilities of the Committee include, but are not limited to, (1) review and approval of an annual budget and operating plan (Section 7.2(a)); (2) decisions on capital expenditures (Section 7.2(d)); establishment and modification of billing procedures (Section 7.2(f)); (3) establishment of, termination of, and approval of any change or amendment to the operating arrangements between Kentucky Power and Agent pertaining to the Mitchell Plant (Section 7.2(h)); and (4) review and approval of plans and procedures designed to ensure compliance with any environmental law, regulation ordinance or permit (Section 7.2(i));

**WHEREAS**, pursuant to Section 7.9 of the Agreement, capital repairs and improvements to the Mitchell Plant will be determined by the Committee pursuant to the annual budgeting process which shall, pursuant to Section 7.10 of the Agreement, remain in effect throughout the applicable operating year subject to such changes, revisions, amendments and updating as the Committee may determine; and

**WHEREAS**, further pursuant to Section 7.9, the expenditures that the Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that owner, and, pursuant to Section 7.2(d), decisions on capital expenditures are among the responsibilities of the Committee.

**NOW, THEREFORE, BE IT RESOLVED**, that Kentucky Power's rights and obligations to operate and maintain the Mitchell Plant are delegated to Wheeling Power, and Wheeling Power accepts and consents to such delegation, effective as of the Effective Date, including, but not limited to, Kentucky Power's rights and obligations under Sections 1.1 (Appointment of Operator), 1.2 (Maintenance of Books and Records), 1.4 (Monthly Statements), 1.5 (Daily Operations), 3.1 (Capital Work), 5.1 (Coal Procurement), 6.3 (Accounting - Operating Expenses), 6.4 (Accounting – Maintenance Expenses), and 7.10 (Budgeting) of the Agreement, including the following which shall occur on or after the Effective Date:

a. Kentucky Power's employees who work at the Mitchell Plant shall become employees of Wheeling Power;

b. All open and active contracts on the Effective Date for the purchase of fuel, transportation, goods and services for the operation, maintenance and improvement of the Mitchell Plant and all collective bargaining agreements for labor at Mitchell Plant shall be assigned by Kentucky Power to Wheeling Power and assumed by Wheeling Power;

c. All leased property used in support of the Mitchell Plant, including but not limited to vehicles and computer equipment, shall be transferred on the books of the lessor from the leased assets account of Kentucky Power to the leased assets account of Wheeling Power; and

d. Ownership or other beneficial interest of the tugboat used at Mitchell Plant shall be transferred to Wheeling Power.

**RESOLVED**, that Wheeling Power will have the power and obligation as the operator of the Mitchell Plant to enter into and hold permits in its name on behalf of both Owners or on its own behalf, as the circumstances require, including the ELG permits, and all existing permits not held by Wheeling Power will be transferred to it in an orderly manner.

**RESOLVED**, that pursuant to Sections 7.2(d) and 7.9 of the Agreement, the Owners jointly recognize Wheeling Power's right to carry out and pay for the ELG Upgrades under the Agreement and approve the following procedures to facilitate that work consistent with the orders of the WVPSC and KPSC, and to protect Kentucky ratepayers from the associated costs and risks:

a. The permits related to the ELG Upgrades at the Mitchell Plant will be transferred to Wheeling Power to the extent not held by Wheeling Power, and all prior action taken by the Owners in furtherance of the foregoing is ratified and approved;

b. All construction and other contracts related to the ELG Upgrades will be in the name of Wheeling Power such that Wheeling Power (and not Kentucky Power) is contractually responsible for those contracts;

c. The appropriate work orders and supporting accounting will be implemented to assign to Wheeling Power all costs associated with the ELG Upgrades;

d. The appropriate work orders and supporting accounting will be implemented to assign to Wheeling Power and Kentucky Power equally all costs associated with the CCR Upgrades;

e. The expenditures associated with the CCR Upgrades, in which the Owners share equally, and the ELG Upgrades, which will be the exclusive responsibility of Wheeling Power, will be classified in accordance with the recommendations of the independent engineer's report identifying the ELG Upgrades and CCR Upgrades and their associated costs, as previously adopted by this Committee.

**RESOLVED**, that to further implement and clarify Sections 3.2 and 7.9 of the Agreement, the Owners approve the following procedures related to capital items which have a depreciable life extending beyond, or with an in-service date not occurring until after, December 31, 2028:

a. Wheeling Power will exclusively pay for any capital item whose in-service date is reasonably expected to be after December 31, 2028;

b. Wheeling Power's Operating Representative may unilaterally authorize any capital expenditure that will be assigned exclusively to Wheeling Power, including the ELG Upgrades;

c. if a capital expenditure has a depreciable life that extends beyond December 31, 2028, Kentucky Power's responsibility for the cost of that item will be limited to its 50% ownership share of the cost of the asset ratably allocated to the portion of such depreciable life occurring prior to December 31, 2028, and Wheeling Power will be responsible for the remainder;

d. any other capital expenditures shall be allocated 50% to (and paid for by) each Owner, subject to the written approval of the Operating Committee;

e. to the extent either Owner funds any capital item in excess of 50%, that capital item will be owned by the Owners in proportion to their investment in that asset for regulatory, tax and other purposes; and

f. an Owner's Operating Representative may unilaterally authorize any capital expenditure for which such Owner shall be allocated greater than 75% of the capital costs, up to an aggregate amount of such capital costs that does not exceed $3 million per year allocated to the other Owner.

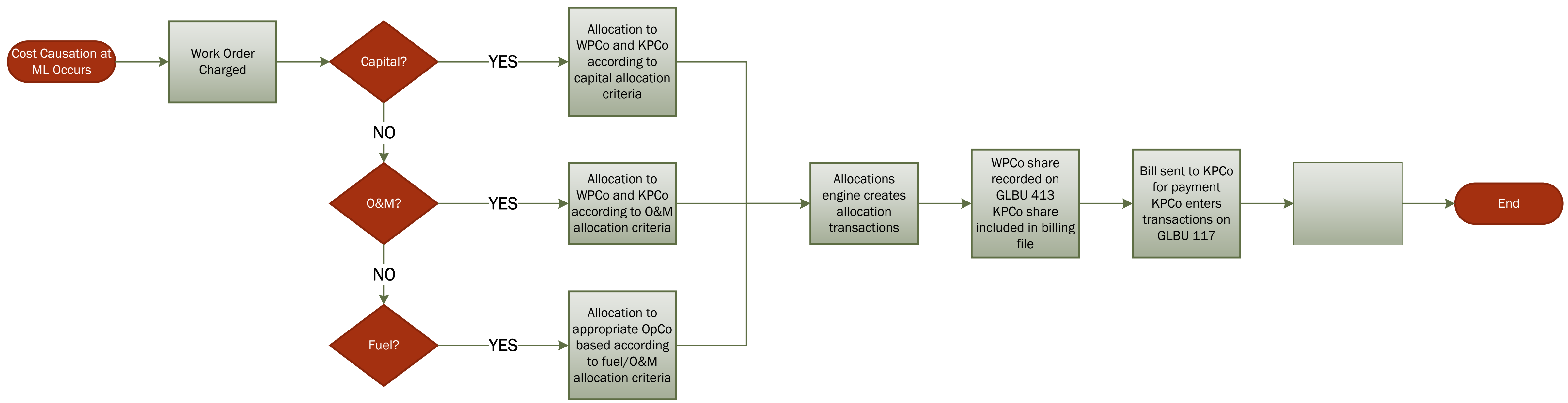
**IN WITNESS WHEREOF**, the undersigned have signed this written consent action effective as of the Effective Date.

**OPERATING REPRESENTATIVES:**

DocuSigned by:
Deryle Brett Mattison
F6E06DC6D8C3445...
D. Brett Mattison

DocuSigned by:
Christian T. Beam
E27434EFE1A34E4...
Christian T. Beam

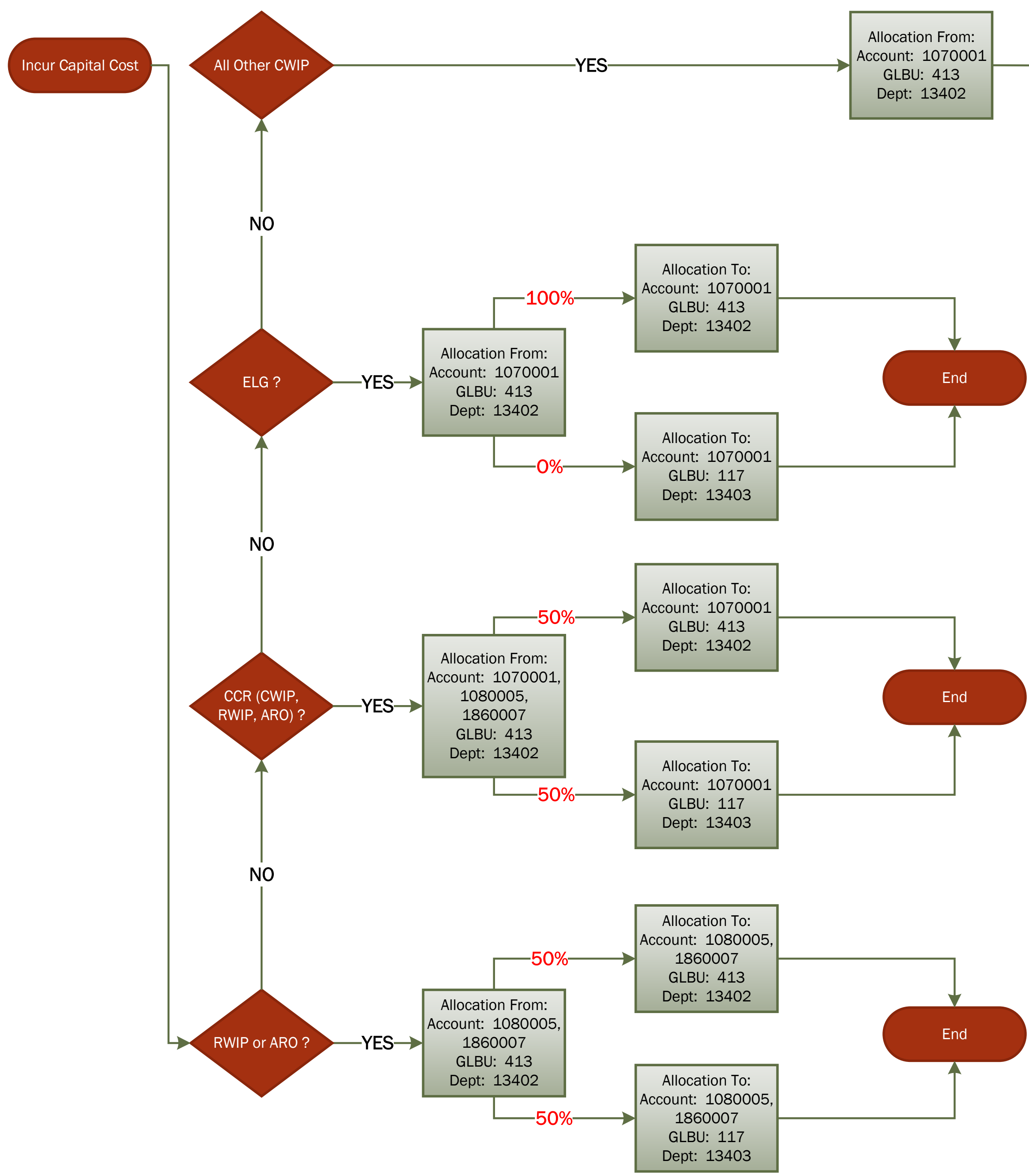
# Mitchell Plant Billing Process (WPCo to KPCo)




Key:
GLBU 117 – Kentucky Power Company Generation
GLBU 413 - Wheeling Power Company Generation

Notes:
The Mitchell Plant joint billing process dictates the allocation of capital and expense transactions incurred in support, directly and indirectly, of the plant. Certain portions of the billings process related to fuel expense occur manually but are included within this process flow document.

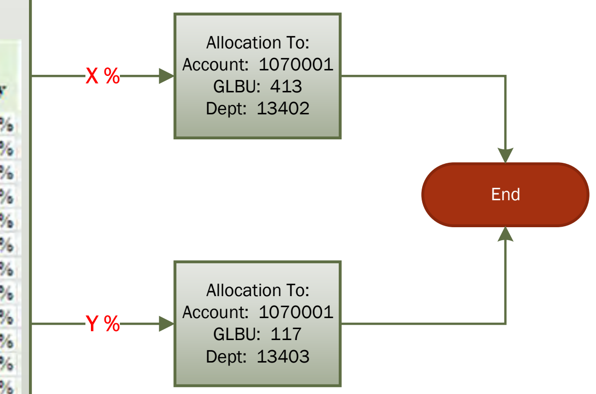
# Mitchell Plant Capital Allocation




## CWIP Allocation Lookup Table

| Month | (X) Wheeling | (Y) Kentucky |
|---|---|---|
| Sep-22 | 82.73% | 17.27% |
| Oct-22 | 82.88% | 17.12% |
| Nov-22 | 83.03% | 16.97% |
| Dec-22 | 83.18% | 16.82% |
| Jan-23 | 83.33% | 16.67% |
| Feb-23 | 83.49% | 16.51% |
| Mar-23 | 83.64% | 16.36% |
| Apr-23 | 83.80% | 16.20% |
| May-23 | 83.96% | 16.04% |
| Jun-23 | 84.12% | 15.88% |
| Jul-23 | 84.29% | 15.71% |
| Aug-23 | 84.45% | 15.55% |
| Sep-23 | 84.62% | 15.38% |
| Oct-23 | 84.78% | 15.22% |
| Nov-23 | 84.95% | 15.05% |
| Dec-23 | 85.12% | 14.88% |
| Jan-24 | 85.29% | 14.71% |
| Feb-24 | 85.47% | 14.53% |
| Mar-24 | 85.64% | 14.36% |
| Apr-24 | 85.82% | 14.18% |
| May-24 | 86.00% | 14.00% |
| Jun-24 | 86.18% | 13.82% |
| Jul-24 | 86.36% | 13.64% |
| Aug-24 | 86.55% | 13.45% |
| Sep-24 | 86.73% | 13.27% |
| Oct-24 | 86.92% | 13.08% |
| Nov-24 | 87.11% | 12.89% |
| Dec-24 | 87.31% | 12.69% |
| Jan-25 | 87.50% | 12.50% |
| Feb-25 | 87.70% | 12.30% |
| Mar-25 | 87.89% | 12.11% |
| Apr-25 | 88.10% | 11.90% |
| May-25 | 88.30% | 11.70% |
| Jun-25 | 88.50% | 11.50% |
| Jul-25 | 88.71% | 11.29% |
| Aug-25 | 88.92% | 11.08% |
| Sep-25 | 89.13% | 10.87% |
| Oct-25 | 89.34% | 10.66% |
| Nov-25 | 89.56% | 10.44% |
| Dec-25 | 89.78% | 10.22% |

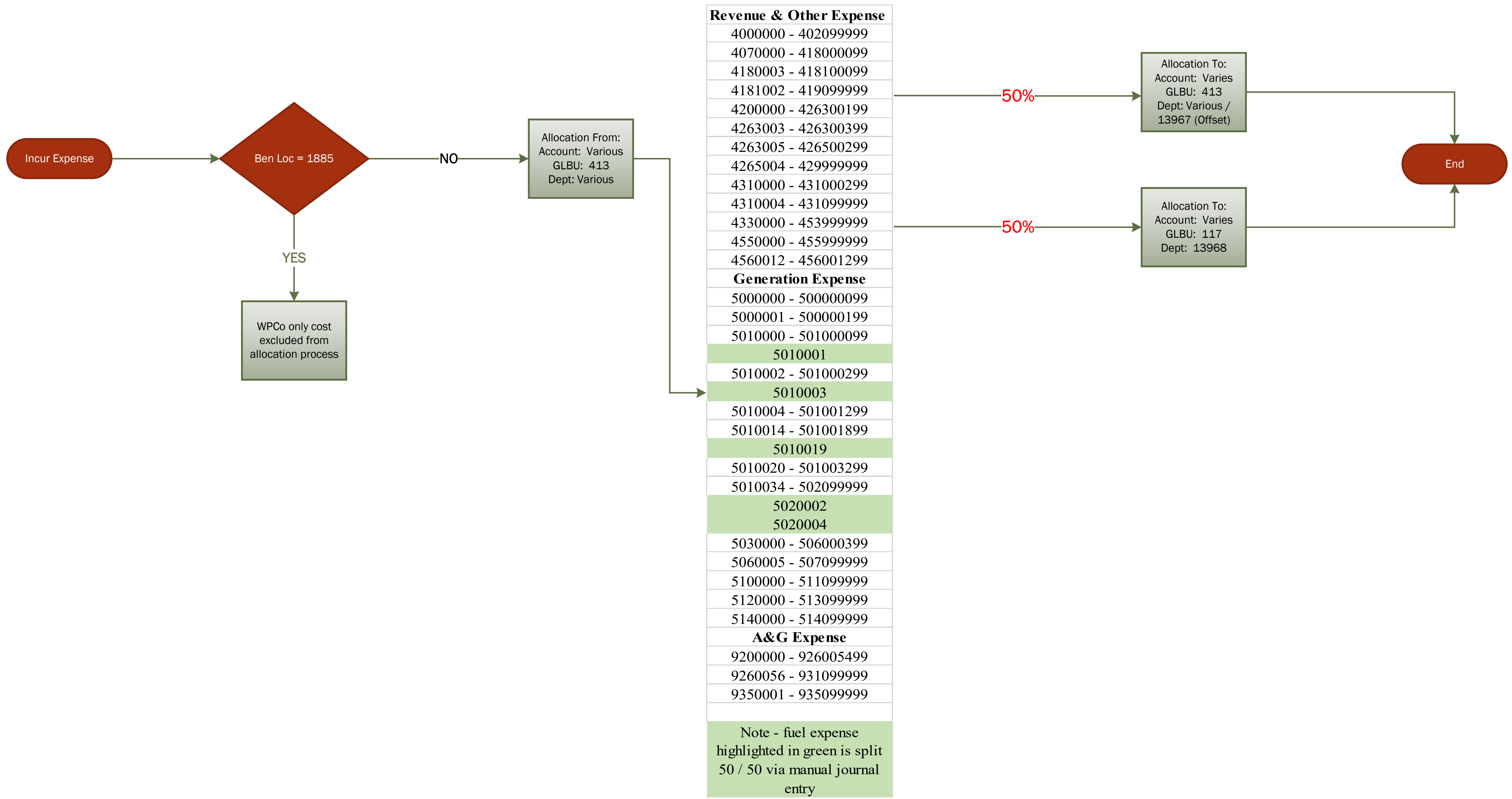
| Month | (X) Wheeling | (Y) Kentucky |
|---|---|---|
| Jan-26 | 90.00% | 10.00% |
| Feb-26 | 90.22% | 9.78% |
| Mar-26 | 90.45% | 9.55% |
| Apr-26 | 90.68% | 9.32% |
| May-26 | 90.91% | 9.09% |
| Jun-26 | 91.14% | 8.86% |
| Jul-26 | 91.38% | 8.62% |
| Aug-26 | 91.62% | 8.38% |
| Sep-26 | 91.86% | 8.14% |
| Oct-26 | 92.11% | 7.89% |
| Nov-26 | 92.35% | 7.65% |
| Dec-26 | 92.60% | 7.40% |
| Jan-27 | 92.86% | 7.14% |
| Feb-27 | 93.11% | 6.89% |
| Mar-27 | 93.37% | 6.63% |
| Apr-27 | 93.64% | 6.36% |
| May-27 | 93.90% | 6.10% |
| Jun-27 | 94.17% | 5.83% |
| Jul-27 | 94.44% | 5.56% |
| Aug-27 | 94.72% | 5.28% |
| Sep-27 | 95.00% | 5.00% |
| Oct-27 | 95.28% | 4.72% |
| Nov-27 | 95.57% | 4.43% |
| Dec-27 | 95.86% | 4.14% |
| Jan-28 | 96.15% | 3.85% |
| Feb-28 | 96.45% | 3.55% |
| Mar-28 | 96.75% | 3.25% |
| Apr-28 | 97.06% | 2.94% |
| May-28 | 97.37% | 2.63% |
| Jun-28 | 97.68% | 2.32% |
| Jul-28 | 98.00% | 2.00% |
| Aug-28 | 98.32% | 1.68% |
| Sep-28 | 98.65% | 1.35% |
| Oct-28 | 98.98% | 1.02% |
| Nov-28 | 99.32% | 0.68% |
| Dec-28 | 99.66% | 0.34% |




**Key:**
GLBU 117 – Kentucky Power Company Generation
GLBU 413 - Wheeling Power Company Generation
DeptID 13402 – Mitchell Plant WPCo's Share
DeptID 13403 – Mitchell Alloc/WPCo Billing

**Notes:**
- WPCo will exclusively pay for any capital item whose in-service date is reasonably expected to be after 12/31/2028.
- If a capital expenditure has a depreciable life that extends beyond 12/31/2028, KPCo's responsibility for the cost of that item will be limited to its 50% ownership share of the cost of the asset ratably allocated to the portion of such depreciable life occurring prior to 12/31/2028. The table above provides for the methodology to meet this requirement.
- Any other capital expenditure will be allocated 50% to each owner.

# Mitchell O&M / A&G / Fuel Expense Allocation




**Key:**
Ben Loc 1885 - WPCo Generation Only (excluded from allocation process)
GLBU 117 – Kentucky Power Company Generation
GLBU 413 - Wheeling Power Company Generation
DeptID 13967 - Mitchell Alloc KPCo Share
DeptID 13968 – Mitchell Plant/KPCo Share

**Notes:**
O&M costs incurred on BU 413 but not included in the list above are EXCLUDED from the joint billing process (i.e. PJM NITS charges billed to the generator but not related to Mitchell plant operation).

# Mitchell Fuel Inventory

| | | | | | TOTAL PILE | | |
|---|---|---|---|---|---|---|---|
| | QUANTITY | DOLLARS | $/QUANTITY | | QUANTITY | DOLLARS | $/QUANTITY |
| ***COAL HIGH SULFUR INVENTORY (FERC ACCT 151)*** | | | | | | | |
| Balance Beginning of Month | 189,876 | $7,972,569.56 | $41.99 | | 379,751 | $15,945,139.12 | $41.99 |
| Added During Month | 57,827 | $2,385,142.21 | $41.25 | | 104,640 | $4,309,773.82 | $41.19 |
| Available for Use During Month | 247,702 | $10,357,711.77 | $41.82 | | 484,391 | $20,254,912.94 | $41.82 |
| Inventory/Survey Adjustments | - | $0.00 | $0.00 | | - | $0.00 | $0.00 |
| Used During Month: Generation Unit #1 | 40,001 | $1,672,649.07 | $41.82 | | 75,317 | $3,149,394.01 | $41.82 |
| Used During Month: Generation Unit #2 | 34,999 | $1,463,489.53 | $41.82 | | 63,670 | $2,662,372.59 | $41.82 |
| Total Consumed | 75,000 | $3,136,138.60 | $41.82 | | 138,987 | $5,811,766.60 | $41.82 |
| Balance End of Month | 172,702 | $7,221,573.17 | $41.82 | | 345,404 | $14,443,146.34 | $41.82 |

Notes:
In any calendar month, the average unit cost of coal available for consumption from Mitchell common coal stockpiles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stockpiles. Each owner's average unit cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each owner based on monthly usage.

The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stockpiles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stockpile at the close of such month and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stockpiles during such month. Such dollar amount shall be credited to the Mitchell Plant fuel stockpile and charged to the Mitchell Plant fuel consumed.

# Mitchell Plant O&M Allocation Source Data

| O&M Step #2: Mitchell O&M | |
|---|---|
| Costs directly charged to Mitchell benefiting locations | |
| Pool Fields - Dollars to be allocated: | |
| Account Range: Tree: Allocation MTCH O&M | 4000000 - 402099999 |
| | 4070000 - 418000099 |
| | 4180003 - 418100099 |
| | 4181002 - 419099999 |
| | 4200000 - 426300199 |
| | 4263003 - 426300399 |
| | 4263005 - 426500299 |
| | 4265004 - 429999999 |
| | 4310000 - 431000299 |
| | 4310004 - 431099999 |
| | 4330000 - 453999999 |
| | 4550000 - 455999999 |
| | 4560012 - 456001299 |
| | 5000000 - 500000099 |
| | 5000001 - 500000199 |
| | 5030000 - 506000399 |
| | 5060005 - 507099999 |
| | 5100000 - 511099999 |
| | 5140000 - 514099999 |
| | 9200000 - 926005499 |
| | 9260056 - 931099999 |
| | 9350001 - 935099999 |
| MITCH O&M MON | 5010000 - 501000099 |
| | 5010002 - 501000299 |
| | 5010004 - 501001299 |
| | 5010014 - 501001899 |
| | 5010020 - 501003299 |
| | 5010034 - 502099999 |
| MTCH VOM | 5120000 - 513099999 |
| GLBU: | 413 |
| Benefiting Loc: | 1267 - Mitchell Plant |
| | 1257 - Mitchell Unit 1 |
| | 1311 - Mitchell Unit 2 |
| Basis to Allocating Capital: | 50% |
| Output: | |
| GLBU: | 413 |
| Dept: | 13968 - Mitchell Plant Liberty Share |
| Account: | 1430080 |
| Work Order: | Blank |
| Project: | Blank |
| CC: | Blank |
| ABM: | Blank |
| GLBU: | 413 |
| Dept: | 13967 - Mitchell Alloc/Liberty Billing |
| Account: | From Pool |
| Work Order: | From Pool |
| Project: | From Pool |
| CC: | From Pool |
| ABM: | From Pool |

# Mitchell Plant Capital Allocation Source Data

| | |
|---|---|
| **Capital Step #1: CWIP** | |
| **Pool Fields - Dollars to be allocated:** | |
| **Account Range:** | 1070001 |
| **GLBU:** | 413 |
| **Cost Component:** | 0 - 022 |
| | 025 - ZZZ |
| **Benefiting Loc:** | 1267 - Mitchell Plant |
| | 1257 - Mitchell Unit 1 |
| | 1311 - Mitchell Unit 2 |
| **Basis to Allocating Capital:** | Stat Entry - Allocation of Non-ELG Mitchell Capital Expenditures |
| **Output:** | |
| **GLBU:** | 117 |
| **Dept:** | 13403 |
| **Account:** | 1070001 |
| **Work Order:** | Child Work Order with ML |
| **Project:** | Project unique for Child Work Order |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **GLBU:** | 413 |
| **Dept:** | 13402 |
| **Account:** | 1070001 |
| **Work Order:** | From Pool |
| **Project:** | From Pool |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **Capital Step #2: RWIP** | |
| **Pool Fields - Dollars to be allocated:** | |
| **Account Range:** | 1080005 |
| **GLBU:** | 413 |
| **Cost Component:** | 0 - 022 |
| | 025 - ZZZ |
| **Benefiting Loc:** | 1267 - Mitchell Plant |
| | 1257 - Mitchell Unit 1 |
| | 1311 - Mitchell Unit 2 |
| **Basis to Allocating Capital:** | 50% |
| **Output:** | |
| **GLBU:** | 117 |
| **Dept:** | 13403 |
| **Account:** | 1080005 |
| **Work Order:** | Child Work Order with ML |
| **Project:** | Project unique for Child Work Order |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **GLBU:** | 413 |
| **Dept:** | 13402 |
| **Account:** | 1080005 |
| **Work Order:** | From Pool |
| **Project:** | From Pool |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **Capital Step #3: ARO** | |
| **Pool Fields - Dollars to be allocated:** | |
| **Account Range:** | 1860007 |
| **GLBU:** | 413 |
| **Cost Component:** | 0 - 022 |
| | 025 - ZZZ |
| **Benefiting Loc:** | 1267 - Mitchell Plant |
| | 1257 - Mitchell Unit 1 |
| | 1311 - Mitchell Unit 2 |
| **Basis to Allocating Capital:** | 50% |
| **Output:** | |
| **GLBU:** | 117 |
| **Dept:** | 13403 |
| **Account:** | 1860007 |
| **Work Order:** | Child Work Order with ML |
| **Project:** | Project unique for Child Work Order |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **GLBU:** | 413 |
| **Dept:** | 13402 |
| **Account:** | 1860007 |
| **Work Order:** | From Pool |
| **Project:** | From Pool |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **Capital Step #4: CWIP/RWIP/ARO - CCR** | |
| **Pool Fields - Dollars to be allocated:** | |
| **Account Range:** | 1070001 |
| | 1080005 |
| | 1860007 |
| **GLBU:** | 413 |
| **Cost Component:** | 0 - 022 |
| | 025 - ZZZ |
| **Benefiting Loc:** | 1962 - CCR Mitchell Plant |
| **Basis to Allocating Capital:** | 50% |
| **Output:** | |
| **GLBU:** | 117 |
| **Dept:** | 13403 |
| **Account:** | 1070001 |
| **Work Order:** | Child Work Order with ML |
| **Project:** | Project unique for Child Work Order |
| **CC:** | From Pool |
| **ABM:** | From Pool |
| **GLBU:** | 413 |
| **Dept:** | 13402 |
| **Account:** | 1070001 |
| **Work Order:** | From Pool |
| **Project:** | From Pool |
| **CC:** | From Pool |
| **ABM:** | From Pool |

Changes each month based on spreadsheet Jeff pulled together.

| Month | (X) Wheeling | (Y) Kentucky | Remaining Dep. Life | Periods prior to Dec. 2028 | Portion of Dep Life before Dec. 2028 | Annual Avg. Wheeling | Annual Avg. Kentucky |
|---|---|---|---|---|---|---|---|
| Sep-22 | 82.73% | 17.27% | 220 | 76 | 34.55% | | |
| Oct-22 | 82.88% | 17.12% | 219 | 75 | 34.25% | | |
| Nov-22 | 83.03% | 16.97% | 218 | 74 | 33.94% | | |
| Dec-22 | 83.18% | 16.82% | 217 | 73 | 33.64% | 82.95% | 17.05% |
| Jan-23 | 83.33% | 16.67% | 216 | 72 | 33.33% | | |
| Feb-23 | 83.49% | 16.51% | 215 | 71 | 33.02% | | |
| Mar-23 | 83.64% | 16.36% | 214 | 70 | 32.71% | | |
| Apr-23 | 83.80% | 16.20% | 213 | 69 | 32.39% | | |
| May-23 | 83.96% | 16.04% | 212 | 68 | 32.08% | | |
| Jun-23 | 84.12% | 15.88% | 211 | 67 | 31.75% | | |
| Jul-23 | 84.29% | 15.71% | 210 | 66 | 31.43% | | |
| Aug-23 | 84.45% | 15.55% | 209 | 65 | 31.10% | | |
| Sep-23 | 84.62% | 15.38% | 208 | 64 | 30.77% | | |
| Oct-23 | 84.78% | 15.22% | 207 | 63 | 30.43% | | |
| Nov-23 | 84.95% | 15.05% | 206 | 62 | 30.10% | | |
| Dec-23 | 85.12% | 14.88% | 205 | 61 | 29.76% | 84.21% | 15.79% |
| Jan-24 | 85.29% | 14.71% | 204 | 60 | 29.41% | | |
| Feb-24 | 85.47% | 14.53% | 203 | 59 | 29.06% | | |
| Mar-24 | 85.64% | 14.36% | 202 | 58 | 28.71% | | |
| Apr-24 | 85.82% | 14.18% | 201 | 57 | 28.36% | | |
| May-24 | 86.00% | 14.00% | 200 | 56 | 28.00% | | |
| Jun-24 | 86.18% | 13.82% | 199 | 55 | 27.64% | | |
| Jul-24 | 86.36% | 13.64% | 198 | 54 | 27.27% | | |
| Aug-24 | 86.55% | 13.45% | 197 | 53 | 26.90% | | |
| Sep-24 | 86.73% | 13.27% | 196 | 52 | 26.53% | | |
| Oct-24 | 86.92% | 13.08% | 195 | 51 | 26.15% | | |
| Nov-24 | 87.11% | 12.89% | 194 | 50 | 25.77% | | |
| Dec-24 | 87.31% | 12.69% | 193 | 49 | 25.39% | 86.28% | 13.72% |
| Jan-25 | 87.50% | 12.50% | 192 | 48 | 25.00% | | |
| Feb-25 | 87.70% | 12.30% | 191 | 47 | 24.61% | | |
| Mar-25 | 87.89% | 12.11% | 190 | 46 | 24.21% | | |
| Apr-25 | 88.10% | 11.90% | 189 | 45 | 23.81% | | |
| May-25 | 88.30% | 11.70% | 188 | 44 | 23.40% | | |
| Jun-25 | 88.50% | 11.50% | 187 | 43 | 22.99% | | |
| Jul-25 | 88.71% | 11.29% | 186 | 42 | 22.58% | | |
| Aug-25 | 88.92% | 11.08% | 185 | 41 | 22.16% | | |
| Sep-25 | 89.13% | 10.87% | 184 | 40 | 21.74% | | |
| Oct-25 | 89.34% | 10.66% | 183 | 39 | 21.31% | | |
| Nov-25 | 89.56% | 10.44% | 182 | 38 | 20.88% | | |
| Dec-25 | 89.78% | 10.22% | 181 | 37 | 20.44% | 88.62% | 11.38% |
| Jan-26 | 90.00% | 10.00% | 180 | 36 | 20.00% | | |
| Feb-26 | 90.22% | 9.78% | 179 | 35 | 19.55% | | |
| Mar-26 | 90.45% | 9.55% | 178 | 34 | 19.10% | | |
| Apr-26 | 90.68% | 9.32% | 177 | 33 | 18.64% | | |
| May-26 | 90.91% | 9.09% | 176 | 32 | 18.18% | | |
| Jun-26 | 91.14% | 8.86% | 175 | 31 | 17.71% | | |
| Jul-26 | 91.38% | 8.62% | 174 | 30 | 17.24% | | |
| Aug-26 | 91.62% | 8.38% | 173 | 29 | 16.76% | | |
| Sep-26 | 91.86% | 8.14% | 172 | 28 | 16.28% | | |
| Oct-26 | 92.11% | 7.89% | 171 | 27 | 15.79% | | |
| Nov-26 | 92.35% | 7.65% | 170 | 26 | 15.29% | | |
| Dec-26 | 92.60% | 7.40% | 169 | 25 | 14.79% | 91.28% | 8.72% |
| Jan-27 | 92.86% | 7.14% | 168 | 24 | 14.29% | | |
| Feb-27 | 93.11% | 6.89% | 167 | 23 | 13.77% | | |
| Mar-27 | 93.37% | 6.63% | 166 | 22 | 13.25% | | |
| Apr-27 | 93.64% | 6.36% | 165 | 21 | 12.73% | | |
| May-27 | 93.90% | 6.10% | 164 | 20 | 12.20% | | |
| Jun-27 | 94.17% | 5.83% | 163 | 19 | 11.66% | | |
| Jul-27 | 94.44% | 5.56% | 162 | 18 | 11.11% | | |
| Aug-27 | 94.72% | 5.28% | 161 | 17 | 10.56% | | |
| Sep-27 | 95.00% | 5.00% | 160 | 16 | 10.00% | | |
| Oct-27 | 95.28% | 4.72% | 159 | 15 | 9.43% | | |
| Nov-27 | 95.57% | 4.43% | 158 | 14 | 8.86% | | |
| Dec-27 | 95.86% | 4.14% | 157 | 13 | 8.28% | 94.33% | 5.67% |
| Jan-28 | 96.15% | 3.85% | 156 | 12 | 7.69% | | |
| Feb-28 | 96.45% | 3.55% | 155 | 11 | 7.10% | | |
| Mar-28 | 96.75% | 3.25% | 154 | 10 | 6.49% | | |
| Apr-28 | 97.06% | 2.94% | 153 | 9 | 5.88% | | |
| May-28 | 97.37% | 2.63% | 152 | 8 | 5.26% | | |
| Jun-28 | 97.68% | 2.32% | 151 | 7 | 4.64% | | |
| Jul-28 | 98.00% | 2.00% | 150 | 6 | 4.00% | | |
| Aug-28 | 98.32% | 1.68% | 149 | 5 | 3.36% | | |
| Sep-28 | 98.65% | 1.35% | 148 | 4 | 2.70% | | |
| Oct-28 | 98.98% | 1.02% | 147 | 3 | 2.04% | | |
| Nov-28 | 99.32% | 0.68% | 146 | 2 | 1.37% | | |
| Dec-28 | 99.66% | 0.34% | 145 | 1 | 0.69% | 97.87% | 2.13% |

# RATE SCHEDULE NO. 303

# MITCHELL PLANT OPERATING AGREEMENT

**KENTUCKY POWER COMPANY**

**WHEELING POWER COMPANY**

**and**

**AMERICAN ELECTRIC POWER SERVICE CORPORATION, AS AGENT**

Tariff Submitter: **Kentucky Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **KPCo Rate Schedules and Service Agreement Tariffs**
Tariff Proposed Effective Date: **12/31/2014**
Tariff Record Title: **Mitchell Plant Operating Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 303**

THIS MITCHELL PLANT OPERATING AGREEMENT ("Agreement"), with an effective date of December 31, 2014 ("Effective Date"), is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo"), and Wheeling Power Company, a West Virginia corporation ("WPCo") (such two parties hereinafter sometimes referred to as the "Owners"); and American Electric Power Service Corporation, a New York corporation qualified as a foreign corporation in West Virginia ("Agent"). KPCo, WPCo and Agent may hereinafter be referred to as a "Party" or collectively as the "Parties".

WITNESSETH:

WHEREAS, KPCo acquired a fifty percent (50%) undivided ownership interest in the Mitchell Power Generation Facility consisting of two 800MW generating units and associated plant, equipment and real estate, located in Moundsville, West Virginia (the "Mitchell Facility") on December 31, 2013; and

WHEREAS, AEP Generation Resources Inc. ("AEPGR"), an affiliate of the Parties, acquired a fifty percent (50%) undivided ownership interest in the Mitchell Facility, also on December 31, 2013; and

WHEREAS, pursuant to an Asset Contribution Agreement between AEPGR and Newco Wheeling Inc., a West Virginia corporation merged or to be merged into WPCo upon the closing of the transactions (the "Transfer Date") set forth in such Asset Contribution Agreement (the "ACA"), AEPGR transferred its fifty percent (50%) undivided interest in the Mitchell Facility to Newco Wheeling Inc., exclusive of its interest in the Conner Run Fly Ash Impoundment and Dam ("Conner Run"), which interest in Conner Run was retained on the Transfer Date by AEPGR; and

WHEREAS, this Agreement shall be effective upon the Effective Date but the rights and obligations set forth herein shall not commence until 12:01 AM on the day following the Transfer Date; and

WHEREAS, the Owners desire that KPCo shall operate and maintain the Mitchell Facility, exclusive of Conner Run (the "Mitchell Plant"), in accordance with the provisions set forth herein; and

WHEREAS, the Owners are subsidiaries of American Electric Power Company, Inc. ("AEP"), the parent company in an integrated public utility holding company system, and use the services of Agent (an affiliated company engaged solely in the business of furnishing essential services to the Owners and to other affiliated companies), as outlined in the service agreements between Agent and KPCo and between Agent and WPCo.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories agree as follows:

## ARTICLE ONE

## FUNCTIONS OF KPCO AND AGENT

1.1 KPCo shall operate and maintain the Mitchell Plant in accordance with good utility practice consistent with procedures employed by KPCo at its other generating stations, and in conformity with the terms and conditions of this Agreement.

1.2 KPCo shall keep all necessary books of record, books of account and memoranda of all transactions involving the Mitchell Plant, and shall make computations and allocations on behalf of the Owners, as required under this Agreement. The books of record, books of account and memoranda shall be kept in such manner as to conform, where so required, to the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") for Public Utilities and Licensees ("Uniform System of Accounts"), and to the rules and regulations of other regulatory bodies having jurisdiction as they may from time to time be in effect.

1.3 The Owners shall establish such bank accounts as may from time to time be required or appropriate.

1.4 As soon as practicable after the end of the month, KPCo shall furnish to WPCo a statement setting forth the dollar amounts associated with the operation and maintenance of the Mitchell Plant as allocated hereunder to KPCo and WPCo for such month. The Owners shall, on a timely basis, deposit sufficient dollar amounts in the appropriate bank accounts to cover their respective allocations of such costs.

1.5 KPCo shall be responsible for the day to day operation and maintenance of the Mitchell Plant. KPCo shall obtain such materials, labor and other services as it considers necessary in connection with the performance of the functions to be performed by it hereunder from such sources or through such persons as it may designate.

1.6 Agent, as directed by the Operating Committee and consistent with Agent's service agreements with KPCo and WPCo, shall provide services necessary for the safe and efficient operation and maintenance of the Mitchell Plant.

ARTICLE TWO

APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The Total Net Capability of the Mitchell Plant at the Mitchell Unit 1 and Unit 2 low-voltage busses, after taking into account auxiliary load demand, is 1,560,000 kilowatts. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The Total Net Generation of the Mitchell Plant during a given period, as determined by the requirements of KPCo and WPCo, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for the Mitchell Unit 1 and Unit 2 during such period.

2.3 Except as set forth in Section 7.6 (including Section 7.6 Subsections), in any hour, KPCo and WPCo shall share the minimum load responsibility of Mitchell Unit 1 and Unit 2 in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time. Each Owner may independently dispatch its share of the generating capacity between minimum and full load.

2.4 In any hour during which the Mitchell Units are out of service, the energy used by the out-of-service Units' auxiliaries during such hour shall be provided by KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time.

## ARTICLE THREE

## REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 KPCo shall from time to time make or cause to be made any additions to, replacements of, and retirements of, capitalizable facilities associated with the Mitchell Plant in accordance with the approved annual budget.

3.2 The dollar amounts associated with any additions to, replacements of, or retirements of, capitalizable facilities associated with the Mitchell Plant shall be allocated to KPCo and WPCo in respective amounts proportionate to their ownership interests in the Mitchell Plant at the time such additions, replacements, or retirements are made.

## ARTICLE FOUR

## WORKING CAPITAL REQUIREMENTS

4.1 KPCo and WPCo shall periodically mutually determine the amount of funds required for use as working capital in meeting payrolls and other expenses incurred in the operation and maintenance of the Mitchell Plant, and in buying materials and supplies (exclusive of fuel) for the Mitchell Plant.

4.2 KPCo and WPCo shall from time to time provide their share of working capital requirements in respective amounts proportionate to their ownership interests at such time in the Mitchell Plant.

## ARTICLE FIVE

## INVESTMENT IN FUEL

5.1 KPCo and Agent shall establish and maintain reserves of coal in stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply, provided each Owner, subject to the approval of the Operating Committee and subject to no adverse impact on the operation of the Mitchell Plant, will have the right, but not the obligation, to directly purchase coal, transportation and consumables for its ownership interest. For the purposes of this Agreement, "consumables" shall be as defined in FERC account 502.

5.2 Except as provided in Section 5.1 for an Owner to elect to procure coal for its own interest, the Owners shall make such monthly investments in the common coal stock piles associated with the Mitchell Plant as are necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from the common coal stock piles by Mitchell Unit 1 and Unit 2 during such month.

5.3 At any time, KPCo's and WPCo's respective shares of the investment in the common coal stock piles shall be proportionate to their ownership interests in the Mitchell Plant, unless an Owner elects to procure its own coal as provided in Section 5.1, in which case inventories will be separately maintained for accounting purposes.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

ARTICLE SIX

APPORTIONMENT OF STATION COSTS

6.1 Except in the case where an Owner has elected to purchase coal for its own interest as provided for in Section 5.1 (in which case the allocation to the Owners of fuel expense shall be in accordance with procedures and processes approved by the Operating Committee), the allocation to the Owners of fuel expense associated with Mitchell Unit 1 and Unit 2 shall be determined by KPCo and Agent as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the

Mitchell Plant fuel in stock pile and charged to Mitchell Plant fuel consumed.

(c) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For purposes of this Agreement, KPCo's Assigned Capacity in the Mitchell Plant shall be equal to 50% of the Total Net Capability, and WPCo's Assigned Capacity shall be equal to 50% of the Total Net Capability.

6.3 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.5 In each calendar month, KPCo's and WPCo's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with Sections 6.3 and 6.4, shall be allocated as follows:

(a) In each calendar month, KPCo's and WPCo's respective shares of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to Mitchell Unit 1 or Unit 2 or designated as a common expense attributable to both units. In each calendar month, KPCo's and WPCo's respective shares of these expenses shall be proportionate to each Owner's dispatch of the applicable unit, or both units in the case of common expenses, over the previous sixty (60) calendar months. Dispatch is assumed to have been allocated fifty percent (50%) to each Owner for months that are prior to this Agreement.

(c) In each calendar month, KPCo's and WPCo's respective shares of all other operations, maintenance, administrative and general expenses shall be proportionate to their respective ownership interests.

6.6 Each Owner shall bear the cost of all taxes attributable to its respective ownership interest in the Mitchell Plant.

## ARTICLE SEVEN

## OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other

Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

7.2 The Operating Committee shall have the following responsibilities:

(a) Review and approval of an annual budget and annual operating plan, including determination of the emission allowances required to be acquired by KPCo and WPCo. If the Operating Committee fails to approve an annual budget, the approved annual budget from the previous year will continue to apply until such time as the new annual budget is approved.

(b) Establishment and review of procedures and systems for dispatch, notification of dispatch, and unit commitment under this Agreement, including any commitment of Called Capacity pursuant to Section 7.6.2.

(c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages, as well as the return to availability following an unplanned outage.

(d) Decisions on capital expenditures, including unit upgrades and re-powering.

(e) Determinations as to changes in the unit capability and decisions on unit retirement.

(f) Establishment and modification of billing procedures under this Agreement.

(g) Approval of material contracts for fuel, transportation or consumable supply. Establishment of specification of fuels, oversight of fuel inspection and certification procedures, management of fuel inventories, and allocation of rights under fuel supply, transportation and consumable contracts. Establishment of an Owner's procurement rights and procedures if the Owner elects to purchase coal, transportation or consumables for its own interest.

(h) Establishment of, termination of, and approval of any change or amendment to the operating arrangements between KPCo and Agent or any replacement third party with respect to the Mitchell Plant generating units; provided, however, that Agent or any replacement third party shall participate in discussions pursuant to this subsection 7.2(h) only if and to the extent requested to do so by both Owners.

(i) Review and approval of plans and procedures designed to ensure compliance with any environmental law, regulation, ordinance or permit, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one unit for compliance.

(j) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request.

7.4 The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 The Owners will each make an initial unit commitment one business day ahead of real-time dispatch.

7.6 Application of this Section 7.6 (including subsections) is subject to (i) the receipt of any necessary regulatory approvals or waivers expressly granted for this Section 7.6; and (ii) the Operating Committee establishing and approving procedures and systems for dispatch. As used in this Section and subsections of this Section, the terms "Party" or "Parties" refers only to KPCo and WPCo, or both of them, as the case may be.

7.6.1 If Mitchell Unit 1 or Unit 2 is designated to be committed by both Parties, such unit will be brought on line or kept on line. If neither Party designates Mitchell Unit 1 or Unit 2 to be committed, such unit will remain off line or be taken offline.

7.6.2 When a Mitchell Unit is designated to be committed by one Party, but designated not to be committed by the other Party, the unit will be brought on line or kept on line if the Party designating the unit for commitment undertakes to pay any applicable start-up costs for the unit, as well as any applicable minimum running costs for the unit thereafter, in which event the unit shall be brought on line or kept on line, as the case may be. The Party so designating the unit to be committed shall have the right to schedule and dispatch up to all of the Available Capacity of the unit. Available Capacity means that portion of the Owners' aggregate Assigned Capacity that is currently capable of being dispatched. The Party exercising this right shall be referred to as the "Calling Party," and the capacity called by that Party in excess of its Assigned Capacity Percentage of the Available Capacity of that unit shall be referred to as its "Called Capacity." The other Party shall be referred to as the "Non-Calling Party". The Calling Party shall provide reasonable notice to the Non-Calling Party of its call, including any start-up or shut-down time for the Unit. For purposes of this Agreement, KPCo's Assigned Capacity Percentage shall be 50%, and WPCo's Assigned Capacity Percentage shall be 50%.

7.6.3 The Non-Calling Party can reclaim any Called Capacity attributable to its Assigned Capacity share by giving the Calling Party notice equal to the normal cold start-up time for the unit. At the end of the notice period, the Non-Calling Party shall have the right to schedule and dispatch the recalled capacity. At that point, the Non-

Calling Party shall resume its responsibility for its share of any applicable start-up costs for the unit and prospectively shall bear its responsibility for the costs associated with its Assigned Capacity from the unit.

7.6.4 If any capacity remains available but is not dispatched from a Party's Available Capacity committed as a result of the initial unit commitment, the other Party may only schedule and dispatch such capacity pursuant to agreement with the non-dispatching Party.

7.7 KPCo and WPCo shall be individually responsible for any fees charged by FERC on the basis of the sales or transmission by each of capacity or energy at wholesale in interstate commerce.

7.8 Emission Allowances. On the Transfer Date pursuant to the ACA, AEPGR, the previous owner of WPCo's interest in the Mitchell Plant, will assign to WPCo all Emission Allowances allocated to AEPGR for the Mitchell Plant for each vintage year after 2014, issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Clean Air Interstate Rule 40 CFR Parts 96 and 97, and any amendments thereto ("Emission Allowances"), and all Emission Allowances for 2014 and any vintage year prior to 2014 that were allocated to the Mitchell Plant and that have not been expended as of the date of assignment. To the extent that additional Emission Allowances are required for operation of the Mitchell Plant, KPCo and WPCo will each be responsible for acquiring sufficient Emission

Allowances to satisfy the Emission Allowances required because of its dispatch of energy from the Mitchell Plant, and the Emission Allowances required to satisfy the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree between USEPA and Ohio Power Company entered on December 10, 2007, in Civil Action No. C2-99-1182 and consolidated cases by the U.S. District Court in the Southern District of Ohio. On or before January 10 of each year, Agent shall determine and notify KPCo and WPCo of the number of additional annual Emission Allowances consumed by each of them through December 31 of the previous year, and KPCo and WPCo shall each transfer into the Mitchell Plant U.S. EPA Allowance Transfer System account that number of Emission Allowances with a small compliance margin by January 31 of that year. For seasonal Emission Allowance programs, Agent shall determine and notify KPCo and WPCo of the number of additional seasonal Emission Allowances consumed by each of them during the applicable compliance period by the 10$^{th}$ day of the first month following the end of the compliance period, and KPCo and WPCo shall each transfer into the appropriate Mitchell Plant U.S. EPA Allowance Transfer System Account that number of Emission Allowances with a small compliance margin by the last day of the first month following the end of the compliance period. In the event that KPCo or WPCo fails to surrender the required number of Emission Allowances by January 31 or the last day of the first month following any seasonal compliance period, Agent shall purchase the required number of Emission Allowances, and KPCo or WPCo, as the case may be, shall reimburse Agent for such purchases, with interest at the Federal Funds Rate (as published by the Board of

Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for the Emission Allowances required by the use of the Mitchell Plant by KPCo and WPCo and to correct any imbalance between Emission Allowances supplied and Emission Allowances used through the end of the preceding year by settlement or payment.

7.9 Capital repairs and improvements to the Mitchell Plant will be determined by the Operating Committee pursuant to the annual budgeting process set forth in Section 7.10. Expenditures that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that Owner.

7.10 At least 90 days before the start of each operating year, KPCo and Agent shall submit to the Operating Committee a proposed annual budget with respect to the Mitchell Plant, a proposed annual operating plan, and an estimate and schedule of costs to be incurred for major maintenance or replacement items during the next six-year period. The annual budget shall be presented on a month-by-month basis for each month during the next operating year, and shall include an operating budget, a capital budget, an estimate of the cost of any major repairs that are anticipated will occur during such operating year with respect to the Mitchell Plant, and an itemized estimate of all projected non-fuel variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual budget and final annual operating plan. Once approved, the annual budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine.

## ARTICLE EIGHT

## EFFECTIVE DATE AND TERM

8.1 Subject to FERC approval or acceptance for filing, the Effective Date of this Agreement shall be December 31, 2014.

8.2 Subject to FERC approval or acceptance, if necessary, this Agreement shall remain in force until such time as (i) KPCo or WPCo has divested itself of all or any portion of its ownership interest in the Mitchell Plant, other than assignment or other transfer of such ownership interests to another AEP affiliate; or (ii) either KPCo or WPCo is no longer a direct or indirect wholly owned subsidiary of AEP; or (iii) KPCo and WPCo may mutually agree to terminate this Agreement.

## ARTICLE NINE

## GENERAL

9.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and assigns, but this Agreement may not be assigned by any signatory without the written consent of the others, which consent shall not be unreasonably withheld.

9.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

9.3 The interpretation and performance of this Agreement shall be in accordance with the laws of the State of Ohio, excluding conflict of laws principles that would require the application of the laws of a different jurisdiction.

9.4 This Agreement supersedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories or their representatives with respect to operation of the Mitchell Plant, and constitutes the entire agreement of the signatories with respect to the operation of the Plant. Notwithstanding the foregoing, this Agreement does not supersede any previous agreements among any of the signatories allocating or transferring rights to capacity and associated energy, or ownership, of the Mitchell Plant.

9.5 Each Party shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, facsimile, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
Gregory G. Pauley
President & COO

Attn:

Phone: (502) 696-7007

Facsimile:(502) 696-7006

Email: ggpauley@aep.com

WHEELING POWER COMPANY
Charles R. Patton
President

Attn:

Phone: (304) 348-4152

Facsimile: (304) 348-4198

Email: crpatton@aep.com

AMERICAN ELECTRIC POWER SERVICE CORPORATION
Mark C. McCullough
Executive Vice President – Generation

Attn:

Phone: (614) 716-2400

Facsimile: (614) 716-1331

Email: mcmccullough@aep.com

All notices shall be effective upon receipt, or upon such later date following receipt as set forth in the notice. Any Party may, by written notice to the other Parties, change the representative or the address to which such notices are to be sent.

## ARTICLE TEN

## LIMITATION OF LIABILITY

10.1 Notwithstanding anything in this Agreement to the contrary, neither of the Owners or Agent shall be liable under this Agreement for special, consequential, indirect, punitive or exemplary damages, or for lost profits or business interruption damages, whether arising by statute, in tort or contract or otherwise.

## ARTICLE ELEVEN

## DISPUTE RESOLUTION

11.1 If either Owner believes that a dispute has arisen as to the meaning or application of this Agreement, it shall present that matter to the Operating Committee in writing, and shall provide a copy of that writing to the other Owner.

11.2 If the Operating Committee is unable to reach agreement on a dispute submitted to the Operating Committee pursuant to Section 11.1within thirty (30) days after the dispute is presented to it, the matter shall be referred to the chief operating officers of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner involved in the dispute may invoke the arbitration provisions set forth in Section 11.3 at any time after the end of the thirty (30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

11.3 If the Owners are unable to resolve a dispute through the Operating Committee within thirty (30) days after the dispute is presented to the Operating Committee pursuant to Section 11.1, or through reference of the matter to the chief operating officers of the Owners pursuant to Section 11.2, either Owner may commence arbitration proceedings by providing written notice to the other Owner, detailing the nature of the dispute, designating the issue(s) to be arbitrated, identifying the provisions of this Agreement under which the dispute arose, and setting forth such Owner's proposed resolution of such dispute.

11.3.1 Within ten (10) days of the date of the notice of arbitration, a representative of each Owner shall meet for the purpose of selecting an arbitrator. If the Owners' representatives are unable to agree on an arbitrator within fifteen (15) days of the date of the notice of arbitration, then an arbitrator shall be selected in accordance with the procedures of the American Arbitration Association ("AAA"). Whether the arbitrator is selected by the Owners' representatives or in accordance with the procedures of the AAA, the arbitrator shall have the qualifications and experience in the occupation, profession, or discipline relevant to the subject matter of the dispute.

11.3.2 Any arbitration proceeding shall be subject to the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq.* (1994), as it may be amended, or any successor enactment thereto, and shall be conducted in accordance with the commercial arbitration rules of the AAA in effect on the date of the notice to the extent not inconsistent with the provisions of this Article.

11.3.3 The arbitrator shall be bound by the provisions of this Agreement where applicable, and shall have no authority to modify any terms and conditions of this Agreement in any manner. The arbitrator shall render a decision resolving the dispute in an equitable manner, and may determine that monetary damages are due to an Owner or may issue a directive that an Owner take certain actions or refrain from taking certain actions, but shall not be authorized to order any other form of relief; provided, however, that nothing in this Article shall preclude the arbitrator from rendering a decision that adopts the resolution of the dispute proposed by an Owner. Unless otherwise agreed to by the Owners, the arbitrator shall render a decision within one hundred twenty (120) days of appointment, and shall notify the Owners in writing of such decision and the reasons supporting such decision. The decision of the arbitrator shall be final and binding upon the Owners, and any award may be enforced in any court of competent jurisdiction.

11.3.4 The fees and expenses of the arbitrator shall be shared equally by the Owners, unless the arbitrator specifies a different allocation. All other expenses and costs of the arbitration proceeding shall be the responsibility of the Owner incurring such expenses and costs.

11.3.5 Unless otherwise agreed by the Owners, any arbitration proceedings shall be conducted in Columbus, Ohio.

11.3.6 Except as provided in this Article, the existence, contents, or results of any arbitration proceeding under this Article may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any agencies having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with an arbitration proceeding under pledge of confidentiality.

11.3.7 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through arbitration, as provided in this Article. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. § 791a *et seq.*, as amended from time to time, and any arbitration proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of the FERC proceedings. The arbitrator shall have no authority to modify, and shall be conclusively bound by, any decisions, findings of fact, or orders of FERC; provided, however, that to the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed to arbitration under this Article to secure such a remedy, subject to any FERC decisions, findings, or orders.

11.4 The procedures set forth in this Article shall be the exclusive means for resolving disputes arising under this Agreement and shall survive this Agreement to the extent necessary to resolve any disputes pertaining to this Agreement. Except as provided in Sections 11.3 and 11.3.7, neither Owner shall have the right to bring any dispute for resolution before a court, agency, or other entity having jurisdiction over this Agreement, unless both Owners agree in writing to such procedure.

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: Greg G Pauley
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By:________________________
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:________________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:______________________________
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By: Charles R. Patton
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By:______________________________
Mark C. McCullough

Title: Executive Vice President - Generation

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:________________________
Gregory G. Pauley

Title: President & COO

WHEELING POWER COMPANY

By:________________________
Charles R. Patton

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: [signature]
Mark C. McCullough

Title: Executive Vice President - Generation

**MITCHELL OPERATING COMMITTEE**

**MINTUES**

**August 15, 2023**

Pursuant to notice, a videoconference meeting of the Operating Committee (the "Committee") of the Mitchell Operating Agreement (the "Agreement") was held on November 2, 2021, at 8:00 a.m. (Eastern).

**Operating Representatives Present:**

- Aaron Walker, President and Chief Operating Officer, Wheeling Power Company (WPCo);
- Cynthia Wiseman, President and Chief Operating Officer, Kentucky Power Company (KPCo); and
- Tim Kerns, VP Generating Assets APCo/WPCo, American Electric Power Service Corporation (AEPSC).

Constituting all of the Operating Representatives. Also present were:

- Brian West, VP Regulatory and Finance, KPCo
- John Scalzo, VP Regulatory and Finance, WPCo
- Joshua Snodgrass, Energy Production Supt Sr - Mitchell Plant, AEPSC
- Jeff Dial, Dir Coal Tran & Reagent Procurement, Coal, Reagents and Trans, AEPSC
- Bob Jessee, Mng Dir Generating Assets I&M, AEPSC
- Frank Zeroski, Budget Analyst Staff, Appalachian Power
- John Crespo, Deputy General Counsel-Regulatory & Nuclear, AEPSC

Mr. Crespo acted as Secretary of the meeting of the Operating Committee. Mr. Crespo presented and on motion duly seconded the Operating Representatives approved the agenda for the meeting, attached. Mr. Kerns presided over the meeting, constituting the required annual meeting of the Mitchell Operating Committee pursuant to Section 7.3 of the Agreement.

During the meeting, the agenda items were presented to the Operating Committee Representatives by the attendees as follows, as more fully set forth in the 2023 Annual Meeting Slide Deck:

- 2023 YTD Mitchell Unit Performance –Josh Snodgrass
- 2023 YTD Mitchell Financial Performance –Frank Zeroski
- 2023 and 2024 Fuel and Reagent Status –Jeff Dial
- 2024 Proposed Operating Plan –Tim Kerns
- 2024 Annual Budget Review –Frank Zeroski

The Operating Representatives engaged in general discussions regarding the agenda items and reviewed the Consent Action dated September 1, 2022 regarding the allocation of CCR and ELG costs between WPCo and KPCo at the Mitchell Plant. The Operating Representatives requested that AEPSC prepare additional information regarding the options for the future of the Mitchell Plant after December 31, 2028.

There being no further business, the Operating Committee meeting was adjourned.

## John C Crespo

| | |
|---|---|
| **Subject:** | Mitchell Operating Committee Annual Meeting |
| **Location:** | Microsoft Teams Meeting |
| **Start:** | Tue 8/15/2023 11:30 AM |
| **End:** | Tue 8/15/2023 12:30 PM |
| **Recurrence:** | (none) |
| **Meeting Status:** | Accepted |
| **Organizer:** | Tim Kerns |
| **Required Attendees:** | Cynthia G Wiseman; Aaron D Walker; John C Crespo; John J Scalzo; Brian West; Frank J Zeroski; Kimberly K Chilcote; Joshua D Snodgrass |
| **Optional Attendees:** | Bob Jessee; Jeffrey C Dial |

This will the required annual meeting of the Mitchell Operating Committee. Others will be added to the invitation as the Agenda is finalized. I have attached a copy of the Agreement, the Consent Action transferring the operatorship from KPCo to WPCo and flow diagram describing how the ML costs are allocated to the two OpCos.

If there's a specific topic you'd like to have on the agenda, please let me know.

Agenda items at this time:

- 2023 YTD Unit Performance
- 2023 YTD Capital and O&M Performance
- 2023 and 2024 Fuel and Reagent Inventory and Commitments
- 2024 Operating Plan including Planned Outage Schedule
- 2024 Annual Budget Review and Approval

Thanks!

________________________________________________________________________________

# Microsoft Teams meeting

**Join on your computer, mobile app or room device**
[Click here to join the meeting]

Meeting ID: 261 005 420 739
Passcode: FL5sYC
Download Teams | Join on the web

**Join with a video conferencing device**
953812256@t.plcm.vc
Video Conference ID: 113 657 646 6
Alternate VTC instructions

**Or call in (audio only)**

+1 614-706-7239,,30967535#   United States, Columbus

Phone Conference ID: 309 675 35#

Find a local number | Reset PIN

Learn More | Meeting options

---

# Mitchell Operating Committee 2023 Annual Meeting

August 15, 2023

# Agenda

- Welcome and Introductions – Tim Kerns
- Purpose of Meeting – Tim Kerns
- New Since Last Meeting – Tim Kerns
- 2023 YTD Mitchell Unit Performance – Josh Snodgrass
- 2023 YTD Mitchell Financial Performance – Frank Zeroski
- 2023 and 2024 Fuel and Reagent Status – Jeff Dial
- 2024 Proposed Operating Plan – Tim Kerns
- 2024 Annual Budget Review – Frank Zeroski

# Purpose of Meeting

- Section 7.3 of the Mitchell Operating Agreement requires that the Operating Committee "shall meet at least annually, and at such other times as any Party may reasonably request."
- This meeting will serve as the 2023 annual meeting.
- In this meeting we'll review, and approve where required, the Mitchell Plant's
  - 2023 YTD operational and financial performance,
  - 2023 and 2024 fuel and reagent status,
  - 2024 Mitchell Plant Operating Plan
  - 2024 Mitchell Budget

# New Since Last Meeting

- Key items from the 9/1/22 Consent Action
  - Cost Allocation Process approved and implemented
    - Link to Mitchell Cost Allocation Flow Chart included in Appendix A
  - Operatorship of the Mitchell Plant transferred to Wheeling Power from Kentucky Power
- Internal audit of the Mitchell Cost Allocation process resulting in a "Well Controlled" rating.
  - The audit identified one Process Improvement recommendation which is:
    - Formalize The Unilateral Capital Project Decision Process – due 10/27/23
- Verification of Operating Representatives for WPCo and KPCo
  - WPCo
    - Aaron Walker – Primary
    - John Scalzo – Alternate
  - KPCo
    - Cindy Wiseman – Primary
    - Brian West - Alternate

# 2023 YTD Unit Performance

| | NCF (%) | EAF (%) | EFOR (%) | AF (%) | FOF (%) | POF (%) | MOF (%) |
|---|---|---|---|---|---|---|---|
| Unit 1 | 25.34 | 52.37 | 25.43 | 55.68 | 13.80 | 15.23 | 15.28 |
| Unit 2 | 23.85 | 53.71 | 23.77 | 58.33 | 11.08 | 8.62 | 21.96 |
| **Plant** | **24.60** | **53.05** | **24.61** | **57.02** | **12.43** | **11.89** | **18.66** |

Key Contributors to Unit Performance:

- *Josh*

# 2023 YTD Financial Performance

| Sum of YTD Jul Act, Tot Yr FC | Column Labels | | | |
|---|---|---|---|---|
| | YTD (07) Jul | | YTD (07) Jul Total | Total Year Total |
| Row Labels | 117 Kentucky Power Co - Gene | 413 Wheeling Power Co - Generation | | |
| **Capital** | **6,604,770** | **57,349,114** | **63,953,884** | **122,283,266** |
| Project Solutions - MLWPC0ELG ML PCC U0 ELG Compliance | 4,615,797 | 44,861,215 | 49,477,012 | 85,755,730 |
| Project Solutions - MLWEC1CTF ML E U1 Cooling Tower Compnnts | 236,311 | 1,243,672 | 1,479,983 | 8,624,243 |
| Plant PPB - GWSCB Cap Blkt - Prod Plant Blnkt | 1,003,617 | 2,666,234 | 3,669,851 | 6,989,687 |
| Plant PPB - OUTCB Cap Blk - Outage | 11,332 | 1,523,531 | 1,534,863 | 5,352,004 |
| Project Solutions - MLWSC1AHB ML S U1 Air Heater Basket Rplc | 16,591 | 133,186 | 149,777 | 4,499,056 |
| Project Solutions - MLWPC0LIM ML PCC U0 Lime Conversion | 542,359 | 2,856,247 | 3,398,606 | 2,840,879 |
| Plant CI - MLWEC1VHL ML E U1 VHP/HP&LPA Turbn Insp | 14,243 | 76,231 | 90,474 | 2,687,955 |
| Project Solutions - 000026265 ML U2 Cooling Tower Reinforce | 199,521 | 1,048,436 | 1,247,957 | 1,486,858 |
| Project Solutions - ML020SP01 ML MITCHELL DSI PROJECT | (0) | | (0) | 1,347,701 |
| Stores Loadings | | (147,382) | (147,382) | 1,140,958 |
| Project Solutions - 000022309 ML U2 ESP Upgrades | | | | 865,559 |
| Plant PPB - EVRCB Cap Blkt - Environmental Repl | - | 681,312 | 681,312 | 728,168 |
| Plant PPB - EROCB Cap Blkt - Env Repl Outage | - | 350,765 | 350,765 | 538,292 |
| Plant CI - MLWVC2CL1 ML V U2 SCR Catalyst Layer 1 | | | | 472,452 |
| Project Solutions - MLWPC2ESP ML PCC U2 ESP Upgrades | 101,089 | 517,165 | 618,254 | 81,051 |
| Contingency/Adjustments | | | | 50,885 |
| Other/IT | 9,363 | 2,094,257 | 2,103,620 | 44,498 |
| Project Solutions - MLWVC2CL4 ML V U2 Catalyst Layer 4 Rplc | 19,480 | 96,154 | 115,634 | 7,679 |
| Plant PPB - EVNCB Cap Blkt - Environmental New | | 182,302 | 182,302 | |
| Project Solutions - MLWPC2CTC ML PCC U2 Cooling Tower Comp | (36,055) | (179,875) | (215,930) | (347,619) |
| Project Solutions - MLWSC2AHB ML S U2 Air Heater Basket Rplc | (128,878) | (654,336) | (783,214) | (882,772) |
| **O&M** | **14,470,955** | **14,622,489** | **29,093,444** | **56,321,195** |
| AEPSC | 3,788,092 | 3,788,089 | 7,576,180 | 13,612,504 |
| Straight Time Labor | 2,810,395 | 2,810,375 | 5,620,770 | 11,262,589 |
| BCO | 3,234,152 | 3,242,352 | 6,476,504 | 11,168,354 |
| NOMI | 771,616 | 775,285 | 1,546,900 | 6,164,333 |
| Sch Out - 1257 Mitchell Plant Unit 1 | 698,510 | 698,509 | 1,397,019 | 3,839,880 |
| Overtime Labor | 597,532 | 597,528 | 1,195,059 | 3,036,363 |
| Sch Out - 1311 Mitchell Plant Unit 2 | 178,858 | 178,857 | 357,715 | 2,323,037 |
| Stores Loadings | 408,943 | 408,943 | 817,886 | 1,415,969 |
| Contingency/Adjustments | | | | 790,489 |
| Project Solutions - MLWSC1AHB ML S U1 Air Heater Basket Rplc | | | | 730,000 |
| Project Solutions - MLWPC2ESP ML PCC U2 ESP Upgrades | 191,738 | 191,738 | 383,476 | 681,000 |
| Other | 235,276 | 374,389 | 609,665 | 547,679 |
| Plant CI - MLWEC1VHL ML E U1 VHP/HP&LPA Turbn Insp | | | | 480,000 |
| Project Solutions - MLWSC2AHB ML S U2 Air Heater Basket Rplc | 95,028 | 95,028 | 190,056 | 189,000 |
| Sch Out - 1267 Mitchell Plant Unit 0 | 30,200 | 30,200 | 60,401 | 80,000 |
| Forced Outage | 1,430,615 | 1,431,196 | 2,861,811 | |
| **Removal** | **1,274,369** | **3,053,346** | **4,327,715** | **8,993,826** |
| **Grand Total** | **22,350,094** | **75,024,949** | **97,375,043** | **187,598,287** |

# Fuel and Reagent Positions

| Mitchell Coal | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Inventory (tons) | | Inventory (Days at FLB) | | % Committed | | $/Ton Delivered | | Est $/MWH | | $/MMBTU | | BTU | |
| | YE 2023 | YE 2024 | YE 2023 | YE 2024 | 2023 | 2024 | 2023 | 2024 | 2023 | 2024 | 2023 | 2024 | 2023 | 2024 |
| High Sulfur | 604,640 | 645,883 | 61 | 65 | 130% | 124% | $69.48 | $58.48 | $27.78 | $23.41 | $2.74 | $2.31 | 12,655 | 12,638 |
| Low Sulfur | 776,535 | 877,391 | 78 | 88 | 217% | 110% | $129.99 | $129.02 | $54.20 | $53.43 | $5.35 | $5.27 | 12,136 | 12,219 |
| Blended @65/35 | | | | | | | **$90.66** | **$83.17** | **$36.78** | **$33.69** | **$3.65** | **$3.35** | **12,473** | **12,491** |

| Mitchell Consumables | | | | |
|---|---|---|---|---|
| | June to Dec 23 | | 2024 | |
| | Total $ | $/MWH | Total $ | $/MWH |
| HRH Hydrated Lime | $1,519,866 | $0.50 | $2,399,414 | $0.55 |
| Hydrated Lime | $17,118 | $0.01 | $28,811 | $0.01 |
| Limestone | $3,419,944 | $1.12 | $5,567,013 | $1.29 |
| Urea | $1,665,253 | $0.56 | $2,671,537 | $0.62 |
| **Total** | **$6,622,180** | | **$10,666,775** | |

- Comments
  - *Jeff*

# 2023 – 2024 Emissions Allowance Position

## Mitchell NOx Allocations for 2023 and 2024 under CSAPR Good Neighbor Plan

| Year | Unit | EPA Allocation | Forecasted Consumption | Position (+ length/ - short) |
|---|---|---|---|---|
| 2023 | ML1 (KP) | 312 | 186 | 126 |
| 2023 | ML2 (KP) | 367 | 219 | 148 |
| 2023 | ML1 (WP) | 312 | 186 | 126 |
| 2023 | ML2 (WP) | 367 | 219 | 148 |
| | | | | |
| 2024 | ML1 (KP) | 316 | 57 | 259 |
| 2024 | ML2 (KP) | 371 | 122 | 249 |
| 2024 | ML1 (WP) | 316 | 57 | 259 |
| 2024 | ML2(WP) | 371 | 122 | 249 |

## Mitchell Allowance Position for Years 2023 and 2024

| | **2023** | **2024** |
|---|---|---|
| WPCo | + 367 | + 689 |
| KPCo | + 274 | + 507 |

# 2024 Proposed Operating Plan

| **Plexos Forecast:** | 2023-20233 Q2-23 4+8 Budget Update; published 5/12/2023 | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Forecast Period:** | 7/1/2023 - 12/31/2032 | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| **Unit Name** | **State** | **Fuel Type** | **Data Item** | **Units** | **Jul-Dec 2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** |
| Mitchell 1 | WV | Coal | Capacity Factor | (%) | 22.7 | 23.3 | 15.9 | 18.9 | 7.0 | 4.1 | 5.2 | 5.7 | 18.6 | 31.7 | 33.3 |
| Mitchell 2 | WV | Coal | Capacity Factor | (%) | 32.9 | 31.4 | 29.4 | 30.0 | 7.7 | 7.8 | 6.5 | 14.2 | 29.9 | 44.7 | 43.2 |
| ** Gray shaded cells indicated years of decrement pricing for fuel inventory management* | | | | | | | | | | | | | | | |

| **Planned Outage Schedule** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2023** | **2024** | | **2025** | | **2026** | | **2027** | | **2028** | |
| | **Fall** | **Spring** | **Fall** | **Spring** | **Fall** | **Spring** | **Fall** | **Spring** | **Fall** | **Spring** | **Fall** |
| Unit 1 | 87 | 0 | 38 | 0 | 58 | 0 | 16 | 0 | 16 | 0 | 58 |
| Unit 2 | 73 | 0 | 38 | 73 | 0 | 16 | 0 | 58 | 0 | 16 | 0 |

- Comments
  - *Tim*

# 2024 Budget Forecast

| Sum of Update Q2 $ | Column Labels | | |
|---|---|---|---|
| | 2024 | | Grand Total |
| Row Labels | 117 Kentucky Power Co - Gene | 413 Wheeling Power Co - Generation | |
| **Capital** | **7,913,532** | **41,328,014** | **49,241,546** |
| Project Solutions - MLWPC0ELG ML PCC U0 ELG Compliance | 3,335,937 | 10,910,371 | 14,246,307 |
| Plant PPB - GWSCB Cap Blkt - Prod Plant Blnkt | 1,527,791 | 9,612,056 | 11,139,847 |
| Project Solutions - 000026265 ML U2 Cooling Tower Reinforce | 918,128 | 5,776,490 | 6,694,619 |
| Project Solutions - 000025624 Mitchell Haul Road Relocate | 701,810 | 4,415,175 | 5,116,985 |
| Plant PPB - OUTCB Cap Blk - Outage | 512,617 | 3,225,265 | 3,737,882 |
| Contingency/Adjustments | 397,615 | 3,325,318 | 3,722,933 |
| Plant PPB - EROCB Cap Blkt - Env Repl Outage | 214,760 | 1,351,243 | 1,566,003 |
| Stores Loadings | 72,113 | 1,247,662 | 1,319,776 |
| Plant PPB - EVRCB Cap Blkt - Environmental Repl | 155,776 | 980,145 | 1,135,922 |
| Plant CI - MLWVC1CL1 ML V U1 SCR Catalyst Layer 1 | 76,984 | 484,289 | 561,273 |
| **O&M** | **28,017,389** | **29,008,445** | **57,025,833** |
| Straight Time Labor | 6,504,757 | 6,504,757 | 13,009,513 |
| AEPSC | 6,362,829 | 6,362,829 | 12,725,657 |
| BCO | 6,062,472 | 6,072,889 | 12,135,361 |
| NOMI | 3,439,597 | 3,439,598 | 6,879,195 |
| Sch Out - 1311 Mitchell Plant Unit 2 | 2,265,000 | 2,265,000 | 4,530,000 |
| Overtime Labor | 1,651,657 | 1,651,657 | 3,303,313 |
| Sch Out - 1257 Mitchell Plant Unit 1 | 1,271,375 | 1,271,375 | 2,542,750 |
| Stores Loadings | 286,610 | 1,267,249 | 1,553,858 |
| Other | 348,912 | 348,912 | 697,825 |
| Sch Out - 1267 Mitchell Plant Unit 0 | 77,500 | 77,500 | 155,000 |
| Contingency/Adjustments | (253,320) | (253,320) | (506,640) |
| **Removal** | **2,176,736** | **2,176,736** | **4,353,472** |
| Plant PPB - GWSCB Cap Blkt - Prod Plant Blnkt | 993,229 | 993,229 | 1,986,457 |
| Contingency/Adjustments | 500,000 | 500,000 | 1,000,000 |
| Plant PPB - OUTCB Cap Blk - Outage | 356,250 | 356,250 | 712,500 |
| Plant PPB - EROCB Cap Blkt - Env Repl Outage | 203,500 | 203,500 | 407,000 |
| Plant PPB - EVRCB Cap Blkt - Environmental Repl | 123,758 | 123,758 | 247,515 |
| **Grand Total** | **38,107,657** | **72,513,195** | **110,620,852** |

# Open Discussion

# Appendix A – Links

- Mitchell Cost Allocation Flow Diagram
  - WPCo KPCo Cost Allocation from Mitchell Flow Diagram FINAL.pdf
- Mitchell 2023 YTD Budget Performance
  - Mitchell 2023 YTD Budget Performance
- Mitchell 2024 Budget Forecast
  - Mitchell 2024 Budget Forecast

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_26** | Refer to Kentucky Power's response to Staff's First Request, Item 16, KPCO_R_KPSC_1_16_Attachment_2.xlsx Excel sheet. |

a. Refer to the Allocators Tab, Cell T443. The construction work in progress allocates $1.8 million to outdoor lighting. Identify the capital project associated with the outdoor lighting allocation. Include in the response whether a CPCN has been, or will be, sought for the project.

b. Refer to the Allocators Tab, Account 365, Cell D579. Explain why the allocation to distribution overhead is higher than the average allocation, with an 82.56 percent distributed to customers. Provide any calculations or workpapers to support the response.

c. Refer to the Allocators Tab, Account 367, Cell D604. Explain why the distribution allocation for underground lines has 67.87 percent allocated to customers. Provide any calculations or workpapers to support the response.

d. Refer to the COSS Tab, Cell AB139. Outdoor lighting class, "Installs on Customer Premises" is allocated $19.9 million. Explain the allocation. Provide any calculations or workpapers to support the response.

**RESPONSE**

a. The requested information is not available. The majority of the $1.8M CWIP allocation to outdoor lighting is comprised of an approximate $1.5M allocation of distribution function CWIP based on the underlying allocation of distribution plant to outdoor lighting. Total Distribution CWIP (approx. $42.6M) serves all distribution level customers and $1.5M is the outdoor lighting class's representative share of their allocated use of the distribution system. This allocated share does not correlate to a specific capital project.

b.&c. The percentages used in the computation of accounts 365 Distribution Overhead Lines and 367 Distribution Underground Lines were derived from the zero-intercept study performed by Witness Wolfram. See attachment KPCO_R_KPSC_PHDR_26_Attachment1

d. The $19.9M allocated to OL is the total balance in account 371 Installations on Cust Premises. This account is comprised of commercial lamp equipment as described in the FERC uniform system of accounts. This allocation to outdoor lighting is consistent with prior cases and the treatment of account 371.

Witness: Katharine I. Walsh

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Primary | 1/0AA | 105.53 | $ 1,893.03 | 1,198 | 1.58 | 54.69 | 34.61 | 3,652.83 |
| 2 | Primary | 2AA | 66.37 | 1,454.85 | 1,335 | 1.09 | 39.82 | 36.53 | 2,424.71 |
| 3 | Primary | 2AS | 66.37 | 122.08 | 112 | 1.09 | 11.54 | 10.58 | 702.38 |
| 4 | Primary | 4/0AA | 211.59 | 4,396.13 | 2,326 | 1.89 | 91.15 | 48.23 | 10,204.78 |
| 5 | Primary | 4/0AL | 211.59 | 756.00 | 400 | 1.89 | 37.80 | 20.00 | 4,231.84 |
| 6 | Primary | 556AL | 556.00 | 27,932.50 | 9,976 | 2.80 | 279.66 | 99.88 | 55,532.94 |
| 7 | Primary | 1/0AL | 105.53 | 1,137.60 | 720 | 1.58 | 42.40 | 26.83 | 2,831.69 |
| 8 | Primary | 2AA | 66.37 | 3,231.27 | 2,964 | 1.09 | 59.35 | 54.45 | 3,613.59 |
| 9 | Primary | 4CU | 41.74 | 896.40 | 270 | 3.32 | 54.55 | 16.43 | 685.86 |
| 10 | Primary | 4/0AA | 211.59 | 3,160.07 | 1,672 | 1.89 | 77.28 | 40.89 | 8,652.01 |
| 11 | Primary | 556AL | 556.00 | 7,209.92 | 2,575 | 2.80 | 142.08 | 50.74 | 28,213.76 |
| 12 | Primary | 750AL | 750.00 | 20,517.17 | 5,399 | 3.80 | 279.22 | 73.48 | 55,109.72 |
| 13 | Primary | 1AA | 83.69 | 638.32 | 404 | 1.58 | 31.76 | 20.10 | 1,682.15 |
| 14 | Primary | 1/0AA | 105.53 | 783,210.31 | 495,703 | 1.58 | 1,112.42 | 704.06 | 74,300.32 |
| 15 | Primary | 1/0AL | 105.53 | 45,646.44 | 28,890 | 1.58 | 268.55 | 169.97 | 17,937.21 |
| 16 | Primary | 1/0AS | 105.53 | 44,413.67 | 28,110 | 1.58 | 264.90 | 167.66 | 17,693.34 |
| 17 | Primary | 1/0CU | 105.53 | 9,689.84 | 2,842 | 3.41 | 181.78 | 53.31 | 5,625.50 |
| 18 | Primary | 1/0CW | 105.53 | 5,801.44 | 1,701 | 3.41 | 140.65 | 41.25 | 4,352.82 |
| 19 | Primary | 2A5 | 66.37 | 1,003.74 | 921 | 1.09 | 33.08 | 30.35 | 2,014.02 |
| 20 | Primary | 2AA | 66.37 | 15,739,381.76 | 14,439,800 | 1.09 | 4,141.97 | 3,799.97 | 252,200.45 |
| 21 | Primary | 2AL | 66.37 | 361,086.50 | 331,272 | 1.09 | 627.36 | 575.56 | 38,199.50 |
| 22 | Primary | 2AS | 66.37 | 3,865,958.84 | 3,546,751 | 1.09 | 2,052.78 | 1,883.28 | 124,991.55 |
| 23 | Primary | 2CC | 66.37 | 6,316.90 | 2,163 | 2.92 | 135.81 | 46.51 | 3,086.92 |
| 24 | Primary | 2CU | 66.37 | 99,842.22 | 34,193 | 2.92 | 539.94 | 184.91 | 12,272.44 |
| 25 | Primary | 2CW | 66.37 | 2,622.15 | 898 | 2.92 | 87.50 | 29.97 | 1,988.85 |
| 26 | Primary | 2Unknown | 66.37 | 660.04 | 606 | 1.09 | 26.82 | 24.61 | 1,633.19 |
| 27 | Primary | 2/0AA | 133.07 | 332.94 | 179 | 1.86 | 24.89 | 13.38 | 1,780.38 |
| 28 | Primary | 2/0AL | 133.07 | 65.10 | 35 | 1.86 | 11.00 | 5.92 | 787.26 |
| 29 | Primary | 2AAA | 66.37 | 137.34 | 126 | 1.09 | 12.24 | 11.22 | 744.99 |
| 30 | Primary | 2ACC | 66.37 | 61,645.45 | 21,111 | 2.92 | 424.27 | 145.30 | 9,643.27 |
| 31 | Primary | 3/0AA | 167.80 | 724.88 | 328 | 2.21 | 40.02 | 18.11 | 3,038.98 |
| 32 | Primary | 3/0AS | 167.80 | 2,194.53 | 993 | 2.21 | 69.64 | 31.51 | 5,287.69 |
| 33 | Primary | 336AS | 336.00 | 4,347.47 | 1,732 | 2.51 | 104.46 | 41.62 | 13,983.65 |
| 34 | Primary | 4A5 | 41.74 | 576.85 | 695 | 0.83 | 21.88 | 26.36 | 1,100.38 |
| 35 | Primary | 4AA | 41.74 | 13,688.36 | 16,492 | 0.83 | 106.59 | 128.42 | 5,360.30 |
| 36 | Primary | 4AL | 41.74 | 6,778.94 | 8,167 | 0.83 | 75.01 | 90.37 | 3,772.20 |
| 37 | Primary | 4AS | 41.74 | 879,488.70 | 1,059,625 | 0.83 | 854.39 | 1,029.38 | 42,966.36 |
| 38 | Primary | 4CC | 41.74 | 1,152.04 | 347 | 3.32 | 61.84 | 18.63 | 777.53 |
| 39 | Primary | 4CU | 41.74 | 14,501,311.12 | 4,367,865 | 3.32 | 6,938.61 | 2,089.94 | 87,234.25 |
| 40 | Primary | 4CW | 41.74 | 24,776.93 | 7,463 | 3.32 | 286.81 | 86.39 | 3,605.85 |
| 41 | Primary | 4Unknown | 41.74 | 341.13 | 411 | 0.83 | 16.83 | 20.27 | 846.20 |
| 42 | Primary | 4/0AA | 211.59 | 117,772.32 | 62,313 | 1.89 | 471.79 | 249.63 | 52,818.97 |
| 43 | Primary | 4/0AL | 211.59 | 5,773.56 | 3,055 | 1.89 | 104.46 | 55.27 | 11,694.73 |
| 44 | Primary | 4/0AS | 211.59 | 30,304.83 | 16,034 | 1.89 | 239.32 | 126.63 | 26,793.18 |
| 45 | Primary | 4/0CU | 211.59 | 27,473.21 | 4,845 | 5.67 | 394.68 | 69.61 | 14,728.63 |
| 46 | Primary | 4AAS | 41.74 | 217.46 | 262 | 0.83 | 13.43 | 16.19 | 675.62 |
| 47 | Primary | 4ACC | 41.74 | 305,950.09 | 167,186 | 1.83 | 748.26 | 408.88 | 17,066.80 |
| 48 | Primary | 556AL | 556.00 | 22,034.89 | 7,870 | 2.80 | 248.39 | 88.71 | 49,323.20 |
| 49 | Primary | 6AA | 26.25 | 6,180.64 | 7,447 | 0.83 | 71.62 | 86.29 | 2,265.29 |
| 50 | Primary | 6AL | 26.25 | 2,695.00 | 3,247 | 0.83 | 47.30 | 56.98 | 1,495.84 |
| 51 | Primary | 6AS | 26.25 | 3,588.47 | 4,323 | 0.83 | 54.58 | 65.75 | 1,726.08 |
| 52 | Primary | 6CC | 26.25 | 762,238.65 | 725,942 | 1.05 | 894.62 | 852.02 | 22,366.43 |
| 53 | Primary | 6CU | 26.25 | 181,019.60 | 172,400 | 1.05 | 435.97 | 415.21 | 10,899.69 |
| 54 | Primary | 6CW | 26.25 | 380.10 | 362 | 1.05 | 19.98 | 19.03 | 499.46 |
| 55 | Primary | 6Unknown | 26.25 | 443.93 | 535 | 0.83 | 19.20 | 23.13 | 607.11 |
| 56 | Primary | 6ACC | 26.25 | 2,488,985.49 | 2,370,462 | 1.05 | 1,616.61 | 1,539.63 | 40,416.84 |
| 57 | Primary | 6ACU | 26.25 | 1,595.93 | 1,520 | 1.05 | 40.94 | 38.99 | 1,023.43 |
| 58 | Primary | 8AA | 16.51 | 571.87 | 689 | 0.83 | 21.79 | 26.25 | 433.34 |
| 59 | Primary | 8CC | 16.51 | 58,743.12 | 70,775 | 0.83 | 220.81 | 266.04 | 4,391.98 |
| 60 | Primary | 8ACC | 16.51 | 97,683.27 | 117,691 | 0.83 | 284.74 | 343.06 | 5,663.59 |
| 61 | Primary | 1/0AA | 105.53 | 22,374.88 | 5,827 | 3.84 | 293.12 | 76.33 | 8,055.54 |
| 62 | Primary | 1/0AL | 105.53 | 18,400.27 | 4,792 | 3.84 | 265.81 | 69.22 | 7,305.11 |
| 63 | Primary | 2AA | 66.37 | 2,324.16 | 848 | 2.74 | 79.80 | 29.12 | 1,932.96 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 64 | Primary | 2AL | 66.37 | 2,400.24 | 876 | 2.74 | 81.10 | 29.60 | 1,964.34 |
| 65 | Primary | 4/0AA | 211.59 | 59,360.12 | 10,773 | 5.51 | 571.90 | 103.79 | 21,961.95 |
| 66 | Primary | 4/0AL | 211.59 | 24,828.94 | 4,506 | 5.51 | 369.87 | 67.13 | 14,203.73 |
| 67 | Primary | 4/0AS | 211.59 | 2,231.55 | 405 | 5.51 | 110.89 | 20.12 | 4,258.20 |
| 68 | Primary | 556AL | 556.00 | 733,327.21 | 103,286 | 7.10 | 2,281.80 | 321.38 | 178,687.64 |
| 69 | Primary | 1AA | 83.69 | 330.22 | 209 | 1.58 | 22.84 | 14.46 | 1,209.89 |
| 70 | Primary | 1/0AA | 105.53 | 3,437,418.97 | 2,175,582 | 1.58 | 2,330.48 | 1,474.99 | 155,656.67 |
| 71 | Primary | 1/0AL | 105.53 | 208,687.01 | 132,080 | 1.58 | 574.22 | 363.43 | 38,352.99 |
| 72 | Primary | 1/0AS | 105.53 | 312,523.61 | 197,800 | 1.58 | 702.70 | 444.75 | 46,934.58 |
| 73 | Primary | 1/0CU | 105.53 | 50,554.49 | 14,825 | 3.41 | 415.20 | 121.76 | 12,849.40 |
| 74 | Primary | 1/0CW | 105.53 | 20,209.65 | 5,927 | 3.41 | 262.52 | 76.98 | 8,124.23 |
| 75 | Primary | 1/0Unknown | 105.53 | 3,432.22 | 2,172 | 1.58 | 73.64 | 46.61 | 4,918.57 |
| 76 | Primary | 2A5 | 66.37 | 381.50 | 350 | 1.09 | 20.39 | 18.71 | 1,241.65 |
| 77 | Primary | 2AA | 66.37 | 3,727,401.52 | 3,419,634 | 1.09 | 2,015.66 | 1,849.23 | 122,731.24 |
| 78 | Primary | 2AL | 66.37 | 83,065.34 | 76,207 | 1.09 | 300.90 | 276.06 | 18,321.54 |
| 79 | Primary | 2AS | 66.37 | 762,514.27 | 699,554 | 1.09 | 911.67 | 836.39 | 55,510.61 |
| 80 | Primary | 2CU | 66.37 | 256,914.44 | 87,984 | 2.92 | 866.14 | 296.62 | 19,686.48 |
| 81 | Primary | 2CW | 66.37 | 25,224.84 | 8,639 | 2.92 | 271.40 | 92.94 | 6,168.62 |
| 82 | Primary | 2/0AS | 133.07 | 2,691.91 | 1,447 | 1.86 | 70.76 | 38.04 | 5,062.45 |
| 83 | Primary | 2/0CU | 133.07 | 3,482.96 | 835 | 4.17 | 120.52 | 28.90 | 3,845.85 |
| 84 | Primary | 2ACC | 66.37 | 11,402.81 | 2,734 | 4.17 | 218.06 | 52.29 | 3,470.59 |
| 85 | Primary | 3/0AA | 167.80 | 3,413.33 | 1,544 | 2.21 | 86.85 | 39.30 | 6,594.55 |
| 86 | Primary | 3/0AL | 167.80 | 1,610.18 | 729 | 2.21 | 59.65 | 26.99 | 4,529.33 |
| 87 | Primary | 3/0AS | 167.80 | 219,777.20 | 99,447 | 2.21 | 696.93 | 315.35 | 52,916.02 |
| 88 | Primary | 3/0CU | 167.80 | 3,730.77 | 760 | 4.91 | 135.34 | 27.57 | 4,625.41 |
| 89 | Primary | 336AA | 336.00 | 26,398.59 | 10,517 | 2.51 | 257.41 | 102.55 | 34,458.21 |
| 90 | Primary | 336AL | 336.00 | 21,957.86 | 8,748 | 2.51 | 234.76 | 93.53 | 31,426.60 |
| 91 | Primary | 336AS | 336.00 | 131,860.21 | 52,534 | 2.51 | 575.30 | 229.20 | 77,012.16 |
| 92 | Primary | 350AL | 350.00 | 2,069.10 | 589 | 3.51 | 85.22 | 24.28 | 8,497.77 |
| 93 | Primary | 397AS | 397.00 | 9,008.16 | 2,642 | 3.41 | 175.27 | 51.40 | 20,404.75 |
| 94 | Primary | 4AA | 41.74 | 4,719.06 | 5,686 | 0.83 | 62.58 | 75.40 | 3,147.32 |
| 95 | Primary | 4AL | 41.74 | 7,344.67 | 8,849 | 0.83 | 78.08 | 94.07 | 3,926.44 |
| 96 | Primary | 4AS | 41.74 | 26,517.71 | 31,949 | 0.83 | 148.36 | 178.74 | 7,460.73 |
| 97 | Primary | 4CU | 41.74 | 2,468,605.02 | 743,556 | 3.32 | 2,862.83 | 862.30 | 35,992.27 |
| 98 | Primary | 4CW | 41.74 | 9,747.45 | 2,936 | 3.32 | 179.89 | 54.18 | 2,261.67 |
| 99 | Primary | 4/0A5 | 211.59 | 756.00 | 400 | 1.89 | 37.80 | 20.00 | 4,231.84 |
| 100 | Primary | 4/0AA | 211.59 | 6,249,724.02 | 3,306,732 | 1.89 | 3,436.86 | 1,818.44 | 384,767.84 |
| 101 | Primary | 4/0AL | 211.59 | 472,858.21 | 250,190 | 1.89 | 945.36 | 500.19 | 105,836.10 |
| 102 | Primary | 4/0AS | 211.59 | 233,696.27 | 123,649 | 1.89 | 664.59 | 351.64 | 74,403.65 |
| 103 | Primary | 4/0CU | 211.59 | 256,379.97 | 45,217 | 5.67 | 1,205.68 | 212.64 | 44,993.50 |
| 104 | Primary | 4ACC | 41.74 | 236,197.81 | 35,412 | 6.67 | 1,255.17 | 188.18 | 7,854.66 |
| 105 | Primary | 556AL | 556.00 | 6,812,539.94 | 2,433,050 | 2.80 | 4,367.51 | 1,559.82 | 867,261.98 |
| 106 | Primary | 6AA | 26.25 | 833.93 | 1,005 | 0.83 | 26.31 | 31.70 | 832.09 |
| 107 | Primary | 6AL | 26.25 | 560.99 | 676 | 0.83 | 21.58 | 26.00 | 682.47 |
| 108 | Primary | 6AS | 26.25 | 607.63 | 732 | 0.83 | 22.46 | 27.06 | 710.28 |
| 109 | Primary | 6CC | 26.25 | 99,136.46 | 94,416 | 1.05 | 322.63 | 307.27 | 8,066.18 |
| 110 | Primary | 6CU | 26.25 | 54,351.89 | 51,764 | 1.05 | 238.89 | 227.52 | 5,972.53 |
| 111 | Primary | 6ACC | 26.25 | 68,858.85 | 65,580 | 1.05 | 268.89 | 256.09 | 6,722.50 |
| 112 | Primary | 795AL | 795.00 | 211.02 | 56 | 3.80 | 28.32 | 7.45 | 5,924.31 |
| 113 | Primary | 8CC | 16.51 | 5,561.72 | 6,701 | 0.83 | 67.94 | 81.86 | 1,351.41 |
| 114 | Primary | 8ACC | 16.51 | 17,378.25 | 20,938 | 0.83 | 120.10 | 144.70 | 2,388.83 |
| 115 | Primary | 2AA | 66.37 | 423.90 | 389 | 1.09 | 21.50 | 19.72 | 1,308.83 |
| 116 | Primary | 556AL | 556.00 | 10,911.51 | 3,897 | 2.80 | 174.79 | 62.43 | 34,708.68 |
| 117 | Primary | 1/0AA | 105.53 | 282.02 | 178 | 1.58 | 21.11 | 13.36 | 1,409.90 |
| 118 | Primary | 1/0AL | 105.53 | 191,923.62 | 121,471 | 1.58 | 550.67 | 348.53 | 36,780.34 |
| 119 | Primary | 1/0CU | 105.53 | 11,268.21 | 3,304 | 3.41 | 196.02 | 57.48 | 6,066.39 |
| 120 | Primary | 2AA | 66.37 | 37,933.99 | 34,802 | 1.09 | 203.34 | 186.55 | 12,381.30 |
| 121 | Primary | 2AL | 66.37 | 18,504.76 | 16,977 | 1.09 | 142.02 | 130.30 | 8,647.56 |
| 122 | Primary | 2CU | 66.37 | 3,162.92 | 1,083 | 2.92 | 96.10 | 32.91 | 2,184.33 |
| 123 | Primary | 4CU | 41.74 | 1,546.49 | 466 | 3.32 | 71.65 | 21.58 | 900.86 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 124 | Primary | 4/0AL | 211.59 | 36,559.57 | 19,344 | 1.89 | 262.86 | 139.08 | 29,428.55 |
| 125 | Primary | 500AL | 500.00 | 450.83 | 161 | 2.80 | 35.53 | 12.69 | 6,344.52 |
| 126 | Primary | 6AL | 26.25 | 505.06 | 609 | 0.83 | 20.47 | 24.67 | 647.56 |
| 127 | Primary | 6CC | 26.25 | 257.25 | 245 | 1.05 | 16.44 | 15.65 | 410.89 |
| 128 | Primary | 6CU | 26.25 | 367.50 | 350 | 1.05 | 19.64 | 18.71 | 491.11 |
| 129 | Primary | 750AL | 750.00 | 25,103.57 | 6,606 | 3.80 | 308.86 | 81.28 | 60,958.91 |
| 130 | Primary | 750CU | 750.00 | 1,140.00 | 300 | 3.80 | 65.82 | 17.32 | 12,990.38 |
| 131 | Primary | 1/0AA | 105.53 | 9,665.54 | 6,117 | 1.58 | 123.58 | 78.21 | 8,254.00 |
| 132 | Primary | 1/0AL | 105.53 | 418.70 | 265 | 1.58 | 25.72 | 16.28 | 1,717.92 |
| 133 | Primary | 1/0AS | 105.53 | 1,308.99 | 828 | 1.58 | 45.48 | 28.78 | 3,037.52 |
| 134 | Primary | 2AA | 66.37 | 27,987.29 | 25,676 | 1.09 | 174.66 | 160.24 | 10,634.88 |
| 135 | Primary | 2AL | 66.37 | 1,075.83 | 987 | 1.09 | 34.24 | 31.42 | 2,085.08 |
| 136 | Primary | 2AS | 66.37 | 5,937.39 | 5,447 | 1.09 | 80.45 | 73.80 | 4,898.35 |
| 137 | Primary | 3/0AS | 167.80 | 556.92 | 252 | 2.21 | 35.08 | 15.87 | 2,663.74 |
| 138 | Primary | 4CU | 41.74 | 27,174.15 | 8,185 | 3.32 | 300.36 | 90.47 | 3,776.26 |
| 139 | Primary | 4/0AA | 211.59 | 68,665.81 | 36,331 | 1.89 | 360.25 | 190.61 | 40,330.97 |
| 140 | Primary | 4/0AL | 211.59 | 2,666.08 | 1,411 | 1.89 | 70.99 | 37.56 | 7,947.03 |
| 141 | Primary | 4/0AS | 211.59 | 563.57 | 298 | 1.89 | 32.64 | 17.27 | 3,653.79 |
| 142 | Primary | 4ACC | 41.74 | 5,137.71 | 1,548 | 3.32 | 130.60 | 39.34 | 1,641.98 |
| 143 | Primary | 556AL | 556.00 | 98,534.73 | 35,191 | 2.80 | 525.26 | 187.59 | 104,301.47 |
| 144 | Primary | 6CC | 26.25 | 852.60 | 812 | 1.05 | 29.92 | 28.50 | 748.04 |
| 145 | Primary | 6ACC | 26.25 | 158.55 | 151 | 1.05 | 12.90 | 12.29 | 322.58 |
| 146 | Seconda | 1/0AA | 105.53 | 2,049.26 | 1,297 | 1.58 | 56.90 | 36.01 | 3,800.58 |
| 147 | Seconda | 1/0AL | 105.53 | 821.60 | 520 | 1.58 | 36.03 | 22.80 | 2,406.47 |
| 148 | Seconda | 2AA | 66.37 | 141,083.14 | 129,434 | 1.09 | 392.15 | 359.77 | 23,877.54 |
| 149 | Seconda | 2AL | 66.37 | 11,264.53 | 10,334 | 1.09 | 110.81 | 101.66 | 6,746.97 |
| 150 | Seconda | 2AS | 66.37 | 4,609.18 | 4,229 | 1.09 | 70.88 | 65.03 | 4,315.83 |
| 151 | Seconda | 2CU | 66.37 | 694.81 | 238 | 2.92 | 45.04 | 15.43 | 1,023.78 |
| 152 | Seconda | 336AL | 336.00 | 439.25 | 175 | 2.51 | 33.20 | 13.23 | 4,444.86 |
| 153 | Seconda | 4AA | 41.74 | 483.89 | 583 | 0.83 | 20.04 | 24.15 | 1,007.83 |
| 154 | Seconda | 4AL | 41.74 | 382.58 | 461 | 0.83 | 17.82 | 21.47 | 896.13 |
| 155 | Seconda | 4AS | 41.74 | 710.48 | 856 | 0.83 | 24.28 | 29.26 | 1,221.21 |
| 156 | Seconda | 4CU | 41.74 | 27,674.96 | 8,336 | 3.32 | 303.12 | 91.30 | 3,810.89 |
| 157 | Seconda | 4CW | 41.74 | 315.40 | 95 | 3.32 | 32.36 | 9.75 | 406.83 |
| 158 | Seconda | 4/0AA | 211.59 | 3,247.01 | 1,718 | 1.89 | 78.34 | 41.45 | 8,770.22 |
| 159 | Seconda | 6CC | 26.25 | 1,220.10 | 1,162 | 1.05 | 35.79 | 34.09 | 894.85 |
| 160 | Seconda | 6CU | 26.25 | 888.30 | 846 | 1.05 | 30.54 | 29.09 | 763.54 |
| 161 | Seconda | 6ACC | 26.25 | 1,082.55 | 1,031 | 1.05 | 33.71 | 32.11 | 842.90 |
| 162 | Seconda | 8ACC | 16.51 | 553.50 | 270 | 2.05 | 33.68 | 16.43 | 271.27 |
| 163 | Seconda | 1AA | 83.69 | 502.44 | 318 | 1.58 | 28.18 | 17.83 | 1,492.40 |
| 164 | Seconda | 1/0AA | 105.53 | 34,093.61 | 21,578 | 1.58 | 232.09 | 146.90 | 15,502.01 |
| 165 | Seconda | 1/0AL | 105.53 | 14,351.58 | 9,083 | 1.58 | 150.58 | 95.31 | 10,057.76 |
| 166 | Seconda | 1/0AS | 105.53 | 82,388.14 | 52,144 | 1.58 | 360.80 | 228.35 | 24,098.16 |
| 167 | Seconda | 1/0CC | 105.53 | 272.80 | 80 | 3.41 | 30.50 | 8.94 | 943.90 |
| 168 | Seconda | 1/0CU | 105.53 | 634.26 | 186 | 3.41 | 46.51 | 13.64 | 1,439.25 |
| 169 | Seconda | 2A5 | 66.37 | 170.04 | 156 | 1.09 | 13.61 | 12.49 | 828.95 |
| 170 | Seconda | 2AA | 66.37 | 119,867.75 | 109,970 | 1.09 | 361.46 | 331.62 | 22,009.15 |
| 171 | Seconda | 2AL | 66.37 | 15,637.23 | 14,346 | 1.09 | 130.55 | 119.78 | 7,949.36 |
| 172 | Seconda | 2AS | 66.37 | 200,762.59 | 184,186 | 1.09 | 467.79 | 429.17 | 28,483.50 |
| 173 | Seconda | 2CC | 66.37 | 1,305.81 | 447 | 2.92 | 61.75 | 21.15 | 1,403.51 |
| 174 | Seconda | 2CU | 66.37 | 45,565.22 | 15,605 | 2.92 | 364.76 | 124.92 | 8,290.69 |
| 175 | Seconda | 2CW | 66.37 | 440.92 | 151 | 2.92 | 35.88 | 12.29 | 815.56 |
| 176 | Seconda | 3/0AL | 167.80 | 230.64 | 124 | 1.86 | 20.71 | 11.14 | 1,868.54 |
| 177 | Seconda | 3/0AS | 167.80 | 1,550.56 | 834 | 1.86 | 53.70 | 28.87 | 4,844.85 |
| 178 | Seconda | 336AL | 336.00 | 960.85 | 383 | 2.51 | 49.11 | 19.57 | 6,574.01 |
| 179 | Seconda | 336AS | 336.00 | 321.28 | 128 | 2.51 | 28.40 | 11.31 | 3,801.40 |
| 180 | Seconda | 4AA | 41.74 | 2,559.65 | 3,084 | 0.83 | 46.09 | 55.53 | 2,317.95 |
| 181 | Seconda | 4AL | 41.74 | 18,938.72 | 22,818 | 0.83 | 125.38 | 151.06 | 6,305.05 |
| 182 | Seconda | 4AS | 41.74 | 27,558.86 | 33,203 | 0.83 | 151.24 | 182.22 | 7,605.78 |
| 183 | Seconda | 4CU | 41.74 | 1,407,423.39 | 423,923 | 3.32 | 2,161.63 | 651.09 | 27,176.64 |
| 184 | Seconda | 4CW | 41.74 | 10,720.26 | 3,229 | 3.32 | 188.66 | 56.82 | 2,371.84 |
| 185 | Seconda | 4/0AA | 211.59 | 1,408.05 | 745 | 1.89 | 51.59 | 27.29 | 5,775.33 |
| 186 | Seconda | 4/0AL | 211.59 | 2,701.88 | 1,430 | 1.89 | 71.46 | 37.81 | 8,000.20 |
| 187 | Seconda | 4/0AS | 211.59 | 923.85 | 489 | 1.89 | 41.79 | 22.11 | 4,678.10 |
| 188 | Seconda | 4/0CU | 211.59 | 504.63 | 89 | 5.67 | 53.49 | 9.43 | 1,996.15 |
| 189 | Seconda | 4ACC | 41.74 | 6,837.73 | 2,060 | 3.32 | 150.67 | 45.38 | 1,894.26 |
| 190 | Seconda | 556AL | 556.00 | 1,089.40 | 260 | 4.19 | 67.56 | 16.12 | 8,965.22 |
| 191 | Seconda | 6AL | 26.25 | 917.15 | 1,105 | 0.83 | 27.59 | 33.24 | 872.62 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 192 | Seconda | 6AS | 26.25 | 654.04 | 788 | 0.83 | 23.30 | 28.07 | 736.90 |
| 193 | Seconda | 6CC | 26.25 | 51,517.14 | 49,064 | 1.05 | 232.58 | 221.50 | 5,814.70 |
| 194 | Seconda | 6CU | 26.25 | 31,286.53 | 29,797 | 1.05 | 181.25 | 172.62 | 4,531.37 |
| 195 | Seconda | 6CW | 26.25 | 11,684.86 | 11,128 | 1.05 | 110.77 | 105.49 | 2,769.26 |
| 196 | Seconda | 6AAL | 26.25 | 1,513.92 | 1,824 | 0.83 | 35.45 | 42.71 | 1,121.13 |
| 197 | Seconda | 6ACC | 26.25 | 42,869.49 | 40,828 | 1.05 | 212.16 | 202.06 | 5,304.27 |
| 198 | Seconda | 8CC | 16.51 | 533.52 | 260 | 2.05 | 33.07 | 16.13 | 266.33 |
| 199 | Seconda | 8CU | 16.51 | 869.25 | 285 | 3.05 | 51.49 | 16.88 | 278.70 |
| 200 | Seconda | 8ACC | 16.51 | 2,130.30 | 526 | 4.05 | 92.89 | 22.93 | 378.63 |
| 201 | Seconda | 1/0AA | 105.53 | 227.50 | 144 | 1.58 | 18.96 | 12.00 | 1,266.31 |
| 202 | Seconda | 1/0AL | 105.53 | 496.12 | 314 | 1.58 | 28.00 | 17.72 | 1,870.01 |
| 203 | Seconda | 2AL | 66.37 | 78.48 | 72 | 1.09 | 9.25 | 8.49 | 563.16 |
| 204 | Seconda | 4CU | 41.74 | 1,152.29 | 347 | 3.32 | 61.85 | 18.63 | 777.61 |
| 205 | Seconda | 4/0AL | 211.59 | 132.30 | 70 | 1.89 | 15.81 | 8.37 | 1,770.30 |
| 206 | Seconda | 1/0AA | 105.53 | 33,419.93 | 21,152 | 1.58 | 229.79 | 145.44 | 15,348.09 |
| 207 | Seconda | 1/0AL | 105.53 | 154,722.24 | 97,925 | 1.58 | 494.43 | 312.93 | 33,023.86 |
| 208 | Seconda | 1/0AS | 105.53 | 89,041.78 | 56,356 | 1.58 | 375.08 | 237.39 | 25,052.35 |
| 209 | Seconda | 1/0CU | 105.53 | 18,183.77 | 5,332 | 3.41 | 249.01 | 73.02 | 7,706.28 |
| 210 | Seconda | 1/0Unknown | 105.53 | 379.20 | 240 | 1.58 | 24.48 | 15.49 | 1,634.88 |
| 211 | Seconda | 2A5 | 66.37 | 207.10 | 190 | 1.09 | 15.02 | 13.78 | 914.83 |
| 212 | Seconda | 2AA | 66.37 | 130,226.55 | 119,474 | 1.09 | 376.76 | 345.65 | 22,940.44 |
| 213 | Seconda | 2AL | 66.37 | 54,641.92 | 50,130 | 1.09 | 244.05 | 223.90 | 14,859.87 |
| 214 | Seconda | 2AS | 66.37 | 229,953.53 | 210,967 | 1.09 | 500.65 | 459.31 | 30,484.01 |
| 215 | Seconda | 2CC | 66.37 | 601.52 | 206 | 2.92 | 41.91 | 14.35 | 952.57 |
| 216 | Seconda | 2CU | 66.37 | 73,102.02 | 25,035 | 2.92 | 462.02 | 158.22 | 10,501.19 |
| 217 | Seconda | 2CW | 66.37 | 1,457.08 | 499 | 2.92 | 65.23 | 22.34 | 1,482.57 |
| 218 | Seconda | 2/0AA | 133.07 | 996.96 | 536 | 1.86 | 43.06 | 23.15 | 3,080.84 |
| 219 | Seconda | 2/0AL | 133.07 | 2,153.88 | 1,158 | 1.86 | 63.29 | 34.03 | 4,528.36 |
| 220 | Seconda | 2/0AS | 133.07 | 2,730.47 | 1,468 | 1.86 | 71.26 | 38.31 | 5,098.58 |
| 221 | Seconda | 3/0AA | 167.80 | 180.42 | 97 | 1.86 | 18.32 | 9.85 | 1,652.64 |
| 222 | Seconda | 3/0AL | 167.80 | 18,179.12 | 9,774 | 1.86 | 183.88 | 98.86 | 16,589.07 |
| 223 | Seconda | 3/0AS | 167.80 | 4,882.13 | 2,625 | 1.86 | 95.29 | 51.23 | 8,596.87 |
| 224 | Seconda | 336AL | 336.00 | 557.51 | 222 | 2.51 | 37.41 | 14.90 | 5,007.60 |
| 225 | Seconda | 336AL | 336.00 | 2,715.96 | 1,082 | 2.51 | 82.57 | 32.89 | 11,052.59 |
| 226 | Seconda | 336AS | 336.00 | 604.91 | 241 | 2.51 | 38.97 | 15.52 | 5,216.12 |
| 227 | Seconda | 336CU | 336.00 | 404.11 | 161 | 2.51 | 31.85 | 12.69 | 4,263.36 |
| 228 | Seconda | 350AL | 350.00 | 988.94 | 394 | 2.51 | 49.82 | 19.85 | 6,947.29 |
| 229 | Seconda | 4AA | 41.74 | 4,794.49 | 5,776 | 0.83 | 63.08 | 76.00 | 3,172.37 |
| 230 | Seconda | 4AL | 41.74 | 26,503.40 | 31,932 | 0.83 | 148.32 | 178.69 | 7,458.72 |
| 231 | Seconda | 4AS | 41.74 | 17,049.98 | 20,542 | 0.83 | 118.96 | 143.33 | 5,982.40 |
| 232 | Seconda | 4CU | 41.74 | 1,259,244.71 | 379,291 | 3.32 | 2,044.67 | 615.87 | 25,706.23 |
| 233 | Seconda | 4CW | 41.74 | 3,821.31 | 1,151 | 3.32 | 112.64 | 33.93 | 1,416.09 |
| 234 | Seconda | 4/0AA | 211.59 | 2,775.49 | 1,469 | 1.89 | 72.43 | 38.32 | 8,108.45 |
| 235 | Seconda | 4/0AL | 211.59 | 16,894.78 | 8,939 | 1.89 | 178.69 | 94.55 | 20,005.28 |
| 236 | Seconda | 4/0AS | 211.59 | 922.32 | 488 | 1.89 | 41.75 | 22.09 | 4,674.22 |
| 237 | Seconda | 4/0CU | 211.59 | 8,383.32 | 2,525 | 3.32 | 166.83 | 50.25 | 10,632.57 |
| 238 | Seconda | 4ACC | 41.74 | 3,817.99 | 1,150 | 3.32 | 112.59 | 33.91 | 1,415.47 |
| 239 | Seconda | 500AL | 500.00 | 4,774.92 | 1,140 | 4.19 | 141.45 | 33.76 | 16,878.98 |
| 240 | Seconda | 6CC | 26.25 | 35,351.71 | 33,668 | 1.05 | 192.66 | 183.49 | 4,816.78 |
| 241 | Seconda | 6CU | 26.25 | 69,884.23 | 66,556 | 1.05 | 270.88 | 257.99 | 6,772.37 |
| 242 | Seconda | 6CW | 26.25 | 6,453.73 | 6,146 | 1.05 | 82.32 | 78.40 | 2,058.05 |
| 243 | Seconda | 6ACC | 26.25 | 31,304.84 | 29,814 | 1.05 | 181.30 | 172.67 | 4,532.70 |
| 244 | Seconda | 750AL | 750.00 | 2,451.79 | 247 | 9.94 | 156.11 | 15.71 | 11,779.03 |
| 245 | Seconda | 8CC | 16.51 | 1,226.65 | 402 | 3.05 | 61.17 | 20.05 | 331.08 |
| 246 | Seconda | 8ACC | 16.51 | 2,203.20 | 544 | 4.05 | 94.46 | 23.32 | 385.05 |
| 247 | Seconda | 1/0AL | 105.53 | 1,565.90 | 991 | 1.58 | 49.74 | 31.48 | 3,322.25 |
| 248 | Seconda | 1/0AS | 105.53 | 758.40 | 480 | 1.58 | 34.62 | 21.91 | 2,312.07 |
| 249 | Seconda | 2AA | 66.37 | 1,080.58 | 991 | 1.09 | 34.32 | 31.49 | 2,089.68 |
| 250 | Seconda | 2AL | 66.37 | 925.40 | 849 | 1.09 | 31.76 | 29.14 | 1,933.82 |
| 251 | Seconda | 2AS | 66.37 | 966.55 | 887 | 1.09 | 32.46 | 29.78 | 1,976.35 |
| 252 | Seconda | 2CU | 66.37 | 338.72 | 116 | 2.92 | 31.45 | 10.77 | 714.82 |
| 253 | Seconda | 2/0AA | 133.07 | 154.38 | 83 | 1.86 | 16.95 | 9.11 | 1,212.34 |
| 254 | Seconda | 2/0AL | 133.07 | 1,112.28 | 598 | 1.86 | 45.48 | 24.45 | 3,254.14 |
| 255 | Seconda | 2/0AL | 133.07 | 109.74 | 59 | 1.86 | 14.29 | 7.68 | 1,022.14 |
| 256 | Seconda | 3/0AL | 167.80 | 2,392.68 | 314 | 7.62 | 135.03 | 17.72 | 2,973.42 |
| 257 | Seconda | 336AA | 336.00 | 80.32 | 32 | 2.51 | 14.20 | 5.66 | 1,900.70 |
| 258 | Seconda | 336AL | 336.00 | 1,459.63 | 582 | 2.51 | 60.53 | 24.11 | 8,102.59 |
| 259 | Seconda | 4CU | 41.74 | 1,553.76 | 468 | 3.32 | 71.82 | 21.63 | 902.97 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 260 | Seconda | 4/0AL | 211.59 | 1,224.72 | 648 | 1.89 | 48.11 | 25.46 | 5,386.25 |
| 261 | Seconda | 6CC | 26.25 | 453.60 | 432 | 1.05 | 21.82 | 20.78 | 545.62 |
| 262 | Seconda | 6CU | 26.25 | 108.15 | 103 | 1.05 | 10.66 | 10.15 | 266.42 |
| 263 | Seconda | 750AL | 750.00 | 2,862.71 | 288 | 9.94 | 168.69 | 16.97 | 12,727.91 |
| 264 | Seconda | 1/0AL | 105.53 | 257.54 | 163 | 1.58 | 20.17 | 12.77 | 1,347.33 |
| 265 | Seconda | 2AA | 66.37 | 318.28 | 292 | 1.09 | 18.63 | 17.09 | 1,134.11 |
| 266 | Seconda | 2AL | 66.37 | 374.96 | 344 | 1.09 | 20.22 | 18.55 | 1,230.96 |
| 267 | Seconda | 2AS | 66.37 | 155.87 | 143 | 1.09 | 13.03 | 11.96 | 793.66 |
| 268 | Seconda | 336AL | 336.00 | 753.00 | 300 | 2.51 | 43.47 | 17.32 | 5,819.68 |
| 269 | Seconda | 4CU | 41.74 | 1,371.16 | 413 | 3.32 | 67.47 | 20.32 | 848.26 |
| 270 | Seconda | 4/0AL | 211.59 | 60.48 | 32 | 1.89 | 10.69 | 5.66 | 1,196.94 |
| 271 | Seconda | 1/0AL | 105.53 | 760.14 | 246 | 3.09 | 48.46 | 15.68 | 1,655.19 |
| 272 | Seconda | 4AL | 41.74 | 1,758.90 | 1,353 | 1.30 | 47.82 | 36.78 | 1,535.33 |
| 273 | Seconda | 1/0AL | 105.53 | 9,881.56 | 3,198 | 3.09 | 174.74 | 56.55 | 5,967.79 |
| 274 | Seconda | 2AL | 66.37 | 3,983.51 | 2,064 | 1.93 | 87.68 | 45.43 | 3,015.22 |
| 275 | Seconda | 2/0AL | 133.07 | 18,608.58 | 4,723 | 3.94 | 270.77 | 68.72 | 9,145.24 |
| 276 | Seconda | 336AL | 336.00 | 93,374.65 | 11,672 | 8.00 | 864.29 | 108.04 | 36,300.18 |
| 277 | Seconda | 350AL | 350.00 | 225.77 | 28 | 8.00 | 42.50 | 5.31 | 1,859.34 |
| 278 | Seconda | 4AL | 41.74 | 716.86 | 491 | 1.46 | 32.35 | 22.16 | 924.90 |
| 279 | Seconda | 4/0AL | 211.59 | 172,701.33 | 30,840 | 5.60 | 983.43 | 175.61 | 37,158.06 |
| 280 | Seconda | 6CU | 26.25 | 4,280.39 | 435 | 9.84 | 205.23 | 20.86 | 547.51 |
| 281 | Seconda | 750AL | 750.00 | 3,787.13 | 381 | 9.94 | 194.02 | 19.52 | 14,639.40 |
| 282 | Seconda | 1AL | 83.69 | 414.06 | 134 | 3.09 | 35.77 | 11.58 | 968.78 |
| 283 | Seconda | 1/0AL | 105.53 | 4,401,714.63 | 1,424,503 | 3.09 | 3,687.99 | 1,193.53 | 125,953.94 |
| 284 | Seconda | 2AL | 66.37 | 31,782.13 | 17,180 | 1.85 | 242.48 | 131.07 | 8,699.03 |
| 285 | Seconda | 2/0AL | 133.07 | 3,279.63 | 901 | 3.64 | 109.26 | 30.02 | 3,994.37 |
| 286 | Seconda | 3/0AL | 167.80 | 5,090.15 | 668 | 7.62 | 196.94 | 25.85 | 4,336.90 |
| 287 | Seconda | 336AL | 336.00 | 88,401.90 | 10,754 | 8.22 | 852.45 | 103.70 | 34,844.49 |
| 288 | Seconda | 350AL | 350.00 | 1,931.70 | 235 | 8.22 | 126.01 | 15.33 | 5,365.39 |
| 289 | Seconda | 4AL | 41.74 | 9,553.65 | 6,544 | 1.46 | 118.10 | 80.89 | 3,376.45 |
| 290 | Seconda | 4CU | 41.74 | 2,534.39 | 576 | 4.40 | 105.60 | 24.00 | 1,001.76 |
| 291 | Seconda | 4/0AL | 211.59 | 652,155.49 | 446,682 | 1.46 | 975.78 | 668.34 | 141,415.95 |
| 292 | Seconda | 4/0Unknown | 211.59 | 765.06 | 311 | 2.46 | 43.38 | 17.64 | 3,731.46 |
| 293 | Seconda | 500AL | 500.00 | 1,676.00 | 400 | 4.19 | 83.80 | 20.00 | 9,999.99 |
| 294 | Seconda | 6CU | 26.25 | 4,398.47 | 447 | 9.84 | 208.04 | 21.14 | 555.01 |
| 295 | Seconda | 1/0AL | 105.53 | 494.40 | 160 | 3.09 | 39.09 | 12.65 | 1,334.87 |
| 296 | Seconda | 2AA | 66.37 | 231.94 | 159 | 1.46 | 18.40 | 12.60 | 836.52 |
| 297 | Seconda | 2AL | 66.37 | 27,939.90 | 19,137 | 1.46 | 201.97 | 138.34 | 9,181.24 |
| 298 | Seconda | 2Unknown | 66.37 | 258.42 | 177 | 1.46 | 19.42 | 13.30 | 882.98 |
| 299 | Seconda | 2/0AL | 133.07 | 29.20 | 20 | 1.46 | 6.53 | 4.47 | 595.12 |
| 300 | Seconda | 336AL | 336.00 | 1,088.00 | 136 | 8.00 | 93.30 | 11.66 | 3,918.40 |
| 301 | Seconda | 4AA | 41.74 | 128.70 | 99 | 1.30 | 12.93 | 9.95 | 415.31 |
| 302 | Seconda | 4AL | 41.74 | 2,576,933.40 | 1,982,256 | 1.30 | 1,830.30 | 1,407.93 | 58,766.84 |
| 303 | Seconda | 4CU | 41.74 | 14,801.57 | 3,364 | 4.40 | 255.20 | 58.00 | 2,420.92 |
| 304 | Seconda | 4Unknown | 41.74 | 4,816.75 | 1,095 | 4.40 | 145.58 | 33.09 | 1,381.03 |
| 305 | Seconda | 4/0AL | 211.59 | 35,433.95 | 4,650 | 7.62 | 519.62 | 68.19 | 14,428.84 |
| 306 | Seconda | 6AL | 26.25 | 1,110.17 | 1,019 | 1.09 | 34.79 | 31.91 | 837.77 |
| 307 | Seconda | 6CC | 26.25 | 9,653.02 | 981 | 9.84 | 308.20 | 31.32 | 822.20 |
| 308 | Seconda | 6CW | 26.25 | 738.00 | 75 | 9.84 | 85.22 | 8.66 | 227.34 |
| 309 | Seconda | 1/0AL | 105.53 | 14,710.63 | 4,761 | 3.09 | 213.20 | 69.00 | 7,281.43 |
| 310 | Seconda | 2AL | 66.37 | 50,031.91 | 23,712 | 2.11 | 324.91 | 153.99 | 10,219.92 |
| 311 | Seconda | 2/0AL | 133.07 | 100,957.13 | 25,624 | 3.94 | 630.69 | 160.07 | 21,301.35 |
| 312 | Seconda | 3/0AL | 167.80 | 408.80 | 73 | 5.60 | 47.85 | 8.54 | 1,433.68 |
| 313 | Seconda | 336AL | 336.00 | 81,263.79 | 10,158 | 8.00 | 806.29 | 100.79 | 33,864.36 |
| 314 | Seconda | 350AL | 350.00 | 698.21 | 87 | 8.00 | 74.74 | 9.34 | 3,269.76 |
| 315 | Seconda | 4AL | 41.74 | 873.08 | 598 | 1.46 | 35.70 | 24.45 | 1,020.71 |
| 316 | Seconda | 4/0AA | 211.59 | 1,198.40 | 214 | 5.60 | 81.92 | 14.63 | 3,095.32 |
| 317 | Seconda | 4/0AL | 211.59 | 109,453.29 | 51,874 | 2.11 | 480.57 | 227.76 | 48,191.72 |
| 318 | Seconda | 556AL | 556.00 | 11,731.92 | 2,800 | 4.19 | 221.71 | 52.91 | 29,420.65 |
| 319 | Seconda | 750AL | 750.00 | 467.18 | 47 | 9.94 | 68.15 | 6.86 | 5,141.74 |
| 320 | Seconda | 1AL | 83.69 | 1,832.37 | 593 | 3.09 | 75.25 | 24.35 | 2,037.98 |
| 321 | Seconda | 1/0AA | 105.53 | 927.49 | 300 | 3.09 | 53.53 | 17.33 | 1,828.33 |
| 322 | Seconda | 1/0AL | 105.53 | 8,763,912.64 | 2,836,218 | 3.09 | 5,203.89 | 1,684.11 | 177,725.54 |
| 323 | Seconda | 1/0AL | 105.53 | 417.15 | 135 | 3.09 | 35.90 | 11.62 | 1,226.16 |
| 324 | Seconda | 1/0XX | 105.53 | 398.61 | 129 | 3.09 | 35.10 | 11.36 | 1,198.60 |
| 325 | Seconda | 2AA | 66.37 | 196.10 | 106 | 1.85 | 19.05 | 10.30 | 683.31 |
| 326 | Seconda | 2AL | 66.37 | 5,819,940.61 | 3,145,914 | 1.85 | 3,281.29 | 1,773.67 | 117,716.86 |
| 327 | Seconda | 2AL | 66.37 | 3,093.53 | 1,672 | 1.85 | 75.65 | 40.89 | 2,713.98 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 365 - Overhead Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 328 | Seconda | 2AL | 66.37 | 342.25 | 185 | 1.85 | 25.16 | 13.60 | 902.72 |
| 329 | Seconda | 2/0AL | 133.07 | 53,525.38 | 14,705 | 3.64 | 441.40 | 121.26 | 16,136.74 |
| 330 | Seconda | 2AAL | 66.37 | 190.55 | 103 | 1.85 | 18.78 | 10.15 | 673.57 |
| 331 | Seconda | 3/0AL | 167.80 | 24,490.63 | 3,214 | 7.62 | 431.99 | 56.69 | 9,512.93 |
| 332 | Seconda | 336AL | 336.00 | 5,416.23 | 659 | 8.22 | 211.00 | 25.67 | 8,624.86 |
| 333 | Seconda | 350AL | 350.00 | 2,153.64 | 262 | 8.22 | 133.05 | 16.19 | 5,665.24 |
| 334 | Seconda | 4AL | 41.74 | 446,533.22 | 305,845 | 1.46 | 807.43 | 553.03 | 23,083.57 |
| 335 | Seconda | 4CU | 41.74 | 19,029.95 | 4,325 | 4.40 | 289.36 | 65.76 | 2,745.02 |
| 336 | Seconda | 4/0AL | 211.59 | 2,235,582.56 | 293,384 | 7.62 | 4,127.36 | 541.65 | 114,608.58 |
| 337 | Seconda | 4/0AL | 211.59 | 1,104.90 | 145 | 7.62 | 91.76 | 12.04 | 2,547.90 |
| 338 | Seconda | 556AL | 556.00 | 519.56 | 124 | 4.19 | 46.66 | 11.14 | 6,191.35 |
| 339 | Seconda | 6AL | 26.25 | 1,221.89 | 1,121 | 1.09 | 36.49 | 33.48 | 878.92 |
| 340 | Seconda | 6CC | 26.25 | 3,426.94 | 348 | 9.84 | 183.63 | 18.66 | 489.89 |
| 341 | Seconda | 750AL | 750.00 | 1,292.13 | 130 | 9.94 | 113.33 | 11.40 | 8,551.09 |
| 342 | Seconda | 1/0AL | 105.53 | 750.87 | 243 | 3.09 | 48.17 | 15.59 | 1,645.06 |
| 343 | Seconda | 1/0AA | 105.53 | 2,348.40 | 760 | 3.09 | 85.19 | 27.57 | 2,909.29 |
| 344 | Seconda | 2AA | 66.37 | 74.00 | 40 | 1.85 | 11.70 | 6.32 | 419.75 |
| 345 | Seconda | 2AL | 66.37 | 680.80 | 368 | 1.85 | 35.49 | 19.18 | 1,273.18 |
| 346 | Seconda | 4AL | 41.74 | 1,159.36 | 794 | 1.46 | 41.14 | 28.18 | 1,176.21 |
| 347 | Seconda | 4CU | 41.74 | 2,875.91 | 866 | 3.32 | 97.71 | 29.43 | 1,228.49 |
| 348 | Seconda | 4/0AL | 211.59 | 8,991.34 | 1,180 | 7.62 | 261.75 | 34.35 | 7,268.32 |
| 349 | Seconda | 500AL | 500.00 | 586.60 | 140 | 4.19 | 49.58 | 11.83 | 5,916.08 |
| 350 | Seconda | 6CC | 26.25 | 980.04 | 100 | 9.84 | 98.20 | 9.98 | 261.98 |
| 351 | Seconda | 1/0AL | 105.53 | 14,337.22 | 4,640 | 3.09 | 210.48 | 68.12 | 7,188.42 |
| 352 | Seconda | 1/0Unknown | 105.53 | 259.56 | 84 | 3.09 | 28.32 | 9.17 | 967.21 |
| 353 | Seconda | 2AL | 66.37 | 6,038.39 | 3,264 | 1.85 | 105.69 | 57.13 | 3,791.75 |
| 354 | Seconda | 4AL | 41.74 | 1,382.62 | 947 | 1.46 | 44.93 | 30.77 | 1,284.48 |
| 355 | Seconda | 4/0AL | 211.59 | 2,407.43 | 316 | 7.62 | 135.44 | 17.77 | 3,760.96 |
| 356 | | TOTAL | | $ 99,128,716.72 | 55,990,937 | | | | |

| # | | | | |
|---|---|---|---|---|
| 357 | | | | |
| 358 | **Zero Intercept Linear Regression Results** | | **LINEST Array** | |
| 359 | | | | |
| 360 | Size Coefficient ($ per MCM) | 0.00307 | 0.00307 | 1.46172 |
| 361 | Zero Intercept ($ per Unit) | 1.46172 | 0.00045 | 0.06820 |
| 362 | R-Square | 0.7821 | 0.78213 | 379.04624 |
| 363 | | | | |
| 364 | **Plant Classification** | | | |
| 365 | | | | |
| 366 | Total Number of Units | 55,990,937 | | |
| 367 | Zero Intercept ($/Unit) | $ 1.46 | | |
| 368 | Minimum System ($/Unit) | $ 0.83 | | |
| 369 | Use Min System (M) or Zero Intercept (Z)? | Z | | |
| 370 | Zero Intercept or Min System Cost ($) | $ 81,843,036 | | |
| 371 | Total Cost of Sample | $ 99,128,717 | | |
| 372 | Percentage of Total | 0.8256 | | |
| 373 | Percentage Classified as Customer-Related | 82.56% | | |
| 374 | Percentage Classified as Demand-Related | 17.44% | | |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 367 - Underground Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Primary | 1/0AL | 105.53 | $ 8,915.71 | 957 | 9.32 | 288.26 | 30.93 | 3,264.00 |
| 2 | Primary | 1/0AL | 105.53 | 2,077.82 | 223 | 9.32 | 139.16 | 14.93 | 1,575.71 |
| 3 | Primary | 2AL | 66.37 | 7,234.18 | 931 | 7.77 | 237.09 | 30.51 | 2,025.11 |
| 4 | Primary | 1/0AL | 105.53 | 18,073.02 | 1,939 | 9.32 | 410.42 | 44.04 | 4,647.16 |
| 5 | Primary | 2AL | 66.37 | 1,554.00 | 200 | 7.77 | 109.88 | 14.14 | 938.60 |
| 6 | Primary | 4/0AL | 211.59 | 10,840.58 | 856 | 12.66 | 370.46 | 29.26 | 6,191.68 |
| 7 | Primary | 1/0AL | 105.53 | 792.20 | 85 | 9.32 | 85.93 | 9.22 | 972.95 |
| 8 | Primary | 1/0AL | 105.53 | 3,165,076.29 | 339,600 | 9.32 | 5,431.25 | 582.75 | 61,498.45 |
| 9 | Primary | 1/0CU | 105.53 | 7,782.20 | 835 | 9.32 | 269.31 | 28.90 | 3,049.46 |
| 10 | Primary | 2AL | 66.37 | 91,308.17 | 11,751 | 7.77 | 842.30 | 108.40 | 7,194.65 |
| 11 | Primary | 2CU | 66.37 | 17,368.51 | 2,235 | 7.77 | 367.36 | 47.28 | 3,137.88 |
| 12 | Primary | 4/0AL | 211.59 | 95,435.00 | 7,538 | 12.66 | 1,099.18 | 86.82 | 18,371.15 |
| 13 | Primary | 500AL | 500.00 | 7,711.20 | 272 | 28.35 | 467.56 | 16.49 | 8,246.21 |
| 14 | Primary | 500CU | 500.00 | 7,101.06 | 250 | 28.35 | 448.68 | 15.83 | 7,913.25 |
| 15 | Primary | 750AL | 750.00 | 138,958.12 | 3,624 | 38.34 | 2,308.17 | 60.20 | 45,152.02 |
| 16 | Primary | 1/0AL | 105.53 | 6,710.40 | 720 | 9.32 | 250.08 | 26.83 | 2,831.69 |
| 17 | Primary | 750AL | 750.00 | 115,089.74 | 3,002 | 38.34 | 2,100.60 | 54.79 | 41,091.64 |
| 18 | Primary | 750AL | 750.00 | 43,785.05 | 1,142 | 38.34 | 1,295.65 | 33.79 | 25,345.34 |
| 19 | Primary | 750AL | 750.00 | 33,739.20 | 880 | 38.34 | 1,137.35 | 29.66 | 22,248.60 |
| 20 | Primary | 1/0AL | 105.53 | 870,516.90 | 93,403 | 9.32 | 2,848.37 | 305.62 | 32,252.30 |
| 21 | Primary | 1/0CU | 105.53 | 30,797.57 | 3,304 | 9.32 | 535.75 | 57.48 | 6,066.39 |
| 22 | Primary | 2AL | 66.37 | 96,172.14 | 12,377 | 7.77 | 864.44 | 111.25 | 7,383.79 |
| 23 | Primary | 2CU | 66.37 | 8,416.41 | 1,083 | 7.77 | 255.73 | 32.91 | 2,184.33 |
| 24 | Primary | 4/0AL | 211.59 | 240,077.72 | 18,963 | 12.66 | 1,743.38 | 137.71 | 29,137.90 |
| 25 | Primary | 500AL | 500.00 | 4,564.69 | 161 | 28.35 | 359.73 | 12.69 | 6,344.52 |
| 26 | Primary | 750AL | 750.00 | 214,213.34 | 5,587 | 38.34 | 2,865.82 | 74.75 | 56,060.69 |
| 27 | Primary | 750CU | 750.00 | 11,502.00 | 300 | 38.34 | 664.07 | 17.32 | 12,990.38 |
| 28 | Primary | 1/0AL | 105.53 | 22,396.99 | 1,711 | 13.09 | 541.46 | 41.36 | 4,365.21 |
| 29 | Primary | 1/0AL | 105.53 | 13,404.16 | 1,024 | 13.09 | 418.88 | 32.00 | 3,376.99 |
| 30 | Primary | 1/0AL | 105.53 | 1,679,726.58 | 128,321 | 13.09 | 4,689.10 | 358.22 | 37,803.28 |
| 31 | Primary | 2AL | 66.37 | 1,942.50 | 250 | 7.77 | 122.85 | 15.81 | 1,049.39 |
| 32 | Primary | 4/0AL | 211.59 | 17,761.95 | 970 | 18.32 | 570.44 | 31.14 | 6,588.43 |
| 33 | Primary | 750AL | 750.00 | 29,381.32 | 629 | 46.68 | 1,171.12 | 25.09 | 18,816.18 |
| 34 | Primary | 750AL | 750.00 | 111,912.39 | 2,397 | 46.68 | 2,285.62 | 48.96 | 36,722.73 |
| 35 | Primary | 750AL | 750.00 | 4,201.20 | 90 | 46.68 | 442.85 | 9.49 | 7,115.12 |
| 36 | Primary | 1/0AL | 105.53 | 367,404.13 | 28,068 | 13.09 | 2,193.02 | 167.53 | 17,680.00 |
| 37 | Primary | 2AL | 66.37 | 6,450.89 | 830 | 7.77 | 223.88 | 28.81 | 1,912.34 |
| 38 | Primary | 4/0AL | 211.59 | 1,741.98 | 95 | 18.32 | 178.64 | 9.75 | 2,063.28 |
| 39 | Primary | 750AL | 750.00 | 47,566.92 | 1,019 | 46.68 | 1,490.11 | 31.92 | 23,941.33 |
| 40 | Secondary | 350AL | 350.00 | 297.07 | 47 | 6.28 | 43.19 | 6.88 | 2,407.22 |
| 41 | Secondary | 1/0AL | 105.53 | 85.84 | 29 | 2.96 | 15.94 | 5.39 | 568.30 |
| 42 | Secondary | 12CU | 6.53 | 3,203.54 | 1,497 | 2.14 | 82.80 | 38.69 | 252.65 |
| 43 | Secondary | 350AL | 350.00 | 2,128.92 | 339 | 6.28 | 115.63 | 18.41 | 6,444.19 |
| 44 | Secondary | 4AL | 41.74 | 595.00 | 340 | 1.75 | 32.27 | 18.44 | 769.65 |
| 45 | Secondary | 6AL | 26.25 | 1,633.60 | 1,008 | 1.62 | 51.44 | 31.76 | 833.61 |
| 46 | Secondary | 6CC | 26.25 | 459.00 | 100 | 4.59 | 45.90 | 10.00 | 262.51 |
| 47 | Secondary | 6CU | 26.25 | 25,956.88 | 5,655 | 4.59 | 345.17 | 75.20 | 1,974.08 |
| 48 | Secondary | 350AL | 350.00 | 4,687.59 | 746 | 6.28 | 171.58 | 27.32 | 9,562.32 |
| 49 | Secondary | 4AL | 41.74 | 325.50 | 186 | 1.75 | 23.87 | 13.64 | 569.26 |
| 50 | Secondary | 4/0AL | 211.59 | 4,367.56 | 1,035 | 4.22 | 135.76 | 32.17 | 6,807.10 |
| 51 | Secondary | 500AL | 500.00 | 1,225.00 | 140 | 8.75 | 103.53 | 11.83 | 5,916.08 |
| 52 | Secondary | 350AL | 350.00 | 35,004.11 | 4,042 | 8.66 | 550.58 | 63.58 | 22,251.98 |
| 53 | Secondary | 4/0AL | 211.59 | 1,137.57 | 208 | 5.46 | 78.81 | 14.43 | 3,054.17 |
| 54 | Secondary | 500AL | 500.00 | 967.21 | 48 | 19.96 | 138.94 | 6.96 | 3,480.56 |
| 55 | Secondary | 1/0AL | 105.53 | 68,446.58 | 23,124 | 2.96 | 450.11 | 152.07 | 16,047.60 |
| 56 | Secondary | 2/0AL | 133.07 | 3,800.64 | 1,284 | 2.96 | 106.07 | 35.83 | 4,768.36 |
| 57 | Secondary | 350AL | 350.00 | 632,003.77 | 100,638 | 6.28 | 1,992.23 | 317.23 | 111,031.97 |
| 58 | Secondary | 350CU | 350.00 | 1,897.33 | 302 | 6.28 | 109.16 | 17.38 | 6,083.58 |
| 59 | Secondary | 4AL | 41.74 | 2,954.52 | 1,688 | 1.75 | 71.91 | 41.09 | 1,715.05 |
| 60 | Secondary | 4CU | 41.74 | 795.15 | 155 | 5.13 | 63.87 | 12.45 | 519.66 |
| 61 | Secondary | 4/0AL | 211.59 | 129,523.86 | 30,693 | 4.22 | 739.32 | 175.19 | 37,069.60 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 367 - Underground Conductors and Devices**

| # | Type | Description | Area from Table of Conductor Sizes Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 62 | Secondary | 4/0CU | 211.59 | 1,133.28 | 269 | 4.22 | 69.16 | 16.39 | 3,467.46 |
| 63 | Secondary | 4/0Unknown | 211.59 | 262.57 | 62 | 4.22 | 33.29 | 7.89 | 1,669.03 |
| 64 | Secondary | 500AL | 500.00 | 38,576.74 | 4,409 | 8.75 | 580.99 | 66.40 | 33,199.28 |
| 65 | Secondary | 6AL | 26.25 | 518.40 | 320 | 1.62 | 28.98 | 17.89 | 469.59 |
| 66 | Secondary | 6CU | 26.25 | 3,249.72 | 708 | 4.59 | 122.13 | 26.61 | 698.49 |
| 67 | Secondary | 8CU | 16.51 | 3,428.28 | 1,602 | 2.14 | 85.65 | 40.02 | 660.77 |
| 68 | | TOTAL | | $ 8,528,369.45 | $ 858,301.87 | | | | |

| # | Zero Intercept Linear Regression Results | | LINEST Array | |
|---|---|---|---|---|
| 69 | | | | |
| 70 | **Zero Intercept Linear Regression Results** | | **LINEST Array** | |
| 71 | | | | |
| 72 | Size Coefficient ($ per MCM) | 0.02032 | 0.02032 | 6.74316 |
| 73 | Zero Intercept ($ per Unit) | 6.74316 | 0.00459 | 0.92178 |
| 74 | R-Square | 0.8307 | 0.83073 | 532.02862 |
| 75 | | | | |
| 76 | **Plant Classification** | | | |
| 77 | | | | |
| 78 | Total Number of Units | 858,302 | | |
| 79 | Zero Intercept ($/Unit) | $ 6.74 | | |
| 80 | Minimum System ($/Unit) | $ 1.62 | | |
| 81 | Use Min System (M) or Zero Intercept (Z)? | Z | | |
| 82 | Zero Intercept or Min System Cost ($) | $ 5,787,666 | | |
| 83 | Total Cost of Sample | $ 8,528,369 | | |
| 84 | Percentage of Total | 0.6786 | | |
| 85 | Percentage Classified as Customer-Related | 67.86% | | |
| 86 | Percentage Classified as Demand-Related | 32.14% | | |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 1 | 10 Feet Wood | 10 | $ 569.37 | 1 | 569.37 | 569.37 | 1.00 | 10.00 |
| 2 | 14 Feet FBGL | 14 | 35,398.08 | 36 | 983.28 | 5,899.68 | 6.00 | 84.00 |
| 3 | 15 Feet Pine | 15 | 569.37 | 1 | 569.37 | 569.37 | 1.00 | 15.00 |
| 4 | 16 Feet Ornamental | 16 | 1,110.78 | 1 | 1,110.78 | 1,110.78 | 1.00 | 16.00 |
| 5 | 17 Feet Alumn | 17 | 149,955.30 | 135 | 1,110.78 | 12,906.10 | 11.62 | 197.52 |
| 6 | 17 Feet FBGL | 17 | 441,492.72 | 449 | 983.28 | 20,835.33 | 21.19 | 360.22 |
| 7 | 17 Feet Ornamental | 17 | 22,215.60 | 20 | 1,110.78 | 4,967.56 | 4.47 | 76.03 |
| 8 | 17 Feet Pine | 17 | 569.37 | 1 | 569.37 | 569.37 | 1.00 | 17.00 |
| 9 | 17 Feet Steel | 17 | 31,101.84 | 28 | 1,110.78 | 5,877.70 | 5.29 | 89.96 |
| 10 | 20  Feet Alumn | 20 | 1,186.70 | 1 | 1,186.70 | 1,186.70 | 1.00 | 20.00 |
| 11 | 20 Feet Pine | 20 | 3,416.22 | 6 | 569.37 | 1,394.67 | 2.45 | 48.99 |
| 12 | 20 Feet Pine | 20 | 1,708.11 | 3 | 569.37 | 986.18 | 1.73 | 34.64 |
| 13 | 20 Feet Pine | 20 | 1,138.74 | 2 | 569.37 | 805.21 | 1.41 | 28.28 |
| 14 | 20 Feet Pine | 20 | 2,846.85 | 5 | 569.37 | 1,273.15 | 2.24 | 44.72 |
| 15 | 20 Feet Pine | 20 | 7,401.81 | 13 | 569.37 | 2,052.89 | 3.61 | 72.11 |
| 16 | 20 Feet Pine | 20 | 5,693.70 | 10 | 569.37 | 1,800.51 | 3.16 | 63.25 |
| 17 | 20 Feet Pine | 20 | 21,066.69 | 37 | 569.37 | 3,463.34 | 6.08 | 121.66 |
| 18 | 20 Feet Pine | 20 | 1,138.74 | 2 | 569.37 | 805.21 | 1.41 | 28.28 |
| 19 | 20 Feet Pine | 20 | 569.37 | 1 | 569.37 | 569.37 | 1.00 | 20.00 |
| 20 | 20 Feet FBGL | 20 | 27,093.54 | 29 | 934.26 | 5,031.14 | 5.39 | 107.70 |
| 21 | 20 Feet Steel | 20 | 2,221.56 | 2 | 1,110.78 | 1,570.88 | 1.41 | 28.28 |
| 22 | 20 Feet Unknown | 20 | 1,708.11 | 3 | 569.37 | 986.18 | 1.73 | 34.64 |
| 23 | 20 Feet Unknown | 20 | 569.37 | 1 | 569.37 | 569.37 | 1.00 | 20.00 |
| 24 | 20 Feet Wood | 20 | 2,277.48 | 4 | 569.37 | 1,138.74 | 2.00 | 40.00 |
| 25 | 24 Feet Steel | 24 | 82,817.02 | 26 | 3,185.27 | 16,241.75 | 5.10 | 122.38 |
| 26 | 24Feet FBGL | 24 | 3,155.34 | 3 | 1,051.78 | 1,821.74 | 1.73 | 41.57 |
| 27 | 25 Feet Aluminum | 25 | 4,207.12 | 4 | 1,051.78 | 2,103.56 | 2.00 | 50.00 |
| 28 | 25 Feet Pine | 25 | 3,985.59 | 7 | 569.37 | 1,506.41 | 2.65 | 66.14 |
| 29 | 25 Feet Pine | 25 | 1,138.74 | 2 | 569.37 | 805.21 | 1.41 | 35.36 |
| 30 | 25 Feet Pine | 25 | 2,846.85 | 5 | 569.37 | 1,273.15 | 2.24 | 55.90 |
| 31 | 25 Feet Pine | 25 | 1,138.74 | 2 | 569.37 | 805.21 | 1.41 | 35.36 |
| 32 | 25 Feet Pine | 25 | 9,109.92 | 16 | 569.37 | 2,277.48 | 4.00 | 100.00 |
| 33 | 25 Feet Pine | 25 | 35,870.31 | 63 | 569.37 | 4,519.23 | 7.94 | 198.43 |
| 34 | 25 Feet Pine | 25 | 9,109.92 | 16 | 569.37 | 2,277.48 | 4.00 | 100.00 |
| 35 | 25 Feet Pine | 25 | 26,760.39 | 47 | 569.37 | 3,903.40 | 6.86 | 171.39 |
| 36 | 25 Feet Pine | 25 | 1,708.11 | 3 | 569.37 | 986.18 | 1.73 | 43.30 |
| 37 | 25 Feet Unknown | 25 | 1,708.11 | 3 | 569.37 | 986.18 | 1.73 | 43.30 |
| 38 | 25 Feet FBGL | 25 | 32,605.18 | 31 | 1,051.78 | 5,856.06 | 5.57 | 139.19 |
| 39 | 25 Feet Steel | 25 | 12,741.08 | 4 | 3,185.27 | 6,370.54 | 2.00 | 50.00 |
| 40 | 25 Feet Wood | 25 | 569.37 | 1 | 569.37 | 569.37 | 1.00 | 25.00 |
| 41 | 30 Feet Alumunum | 30 | 61,469.76 | 22 | 2,794.08 | 13,105.40 | 4.69 | 140.71 |
| 42 | 30 Feet Cedar | 30 | 1,347.92 | 2 | 673.96 | 953.12 | 1.41 | 42.43 |
| 43 | 30 Feet Concrete | 30 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 30.00 |
| 44 | 30 Feet Concrete | 30 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 30.00 |
| 45 | 30 Feet Concrete | 30 | 453.30 | 1 | 453.30 | 453.30 | 1.00 | 30.00 |
| 46 | 30 Feet Douglas Fur | 30 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 30.00 |
| 47 | 30 Feet Douglas Fur | 30 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 30.00 |
| 48 | 30 Feet N/A | 30 | 12,805.24 | 19 | 673.96 | 2,937.72 | 4.36 | 130.77 |
| 49 | 30 Feet Pine | 30 | 16,707.06 | 18 | 928.17 | 3,937.89 | 4.24 | 127.28 |
| 50 | 30 Feet Pine | 30 | 1,751.26 | 2 | 875.63 | 1,238.33 | 1.41 | 42.43 |
| 51 | 30 Feet Pine | 30 | 17,347.47 | 21 | 826.07 | 3,785.53 | 4.58 | 137.48 |
| 52 | 30 Feet Pine | 30 | 24,937.92 | 32 | 779.31 | 4,408.44 | 5.66 | 169.71 |
| 53 | 30 Feet Pine | 30 | 353,734.75 | 485 | 729.35 | 16,062.27 | 22.02 | 660.68 |
| 54 | 30 Feet Pine | 30 | 1,042,945.55 | 1,405 | 742.31 | 27,824.25 | 37.48 | 1,124.50 |
| 55 | 30 Feet Pine | 30 | 22,488,697.28 | 33,368 | 673.96 | 123,111.67 | 182.67 | 5,480.07 |
| 56 | 30 Feet Pine | 30 | 1,078,433.16 | 1,862 | 579.18 | 24,992.14 | 43.15 | 1,294.53 |
| 57 | 30 Feet Pine | 30 | 13,900.32 | 24 | 579.18 | 2,837.39 | 4.90 | 146.97 |
| 58 | 30 Feet Pine | 30 | 1,158.36 | 2 | 579.18 | 819.08 | 1.41 | 42.43 |
| 59 | 30 Feet Pine | 30 | 4,717.72 | 7 | 673.96 | 1,783.13 | 2.65 | 79.37 |
| 60 | 30 Feet Ponderosa Pine | 30 | 729.35 | 1 | 729.35 | 729.35 | 1.00 | 30.00 |
| 61 | 30 Feet Ponderosa Pine | 30 | 742.31 | 1 | 742.31 | 742.31 | 1.00 | 30.00 |
| 62 | 30 Feet Ponderosa Pine | 30 | 3,369.80 | 5 | 673.96 | 1,507.02 | 2.24 | 67.08 |
| 63 | 30 Feet Ponderosa Pine | 30 | 174,912.36 | 302 | 579.18 | 10,065.08 | 17.38 | 521.34 |
| 64 | 30 Feet Ponderosa Pine | 30 | 25,483.92 | 44 | 579.18 | 3,841.85 | 6.63 | 199.00 |
| 65 | 30 Feet Steel | 30 | 3,648.64 | 1 | 3,648.64 | 3,648.64 | 1.00 | 30.00 |
| 66 | 30 Feet Steel | 30 | 40,135.04 | 11 | 3,648.64 | 12,101.17 | 3.32 | 99.50 |
| 67 | 30 Feet Steel | 30 | 76,621.44 | 21 | 3,648.64 | 16,720.17 | 4.58 | 137.48 |
| 68 | 30 Feet Unknown | 30 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 30.00 |
| 69 | 30 Feet Unknown | 30 | 20,892.76 | 31 | 673.96 | 3,752.45 | 5.57 | 167.03 |
| 70 | 30 Feet Unknown | 30 | 14,153.16 | 21 | 673.96 | 3,088.47 | 4.58 | 137.48 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 71 | 30 Feet Wood | 30 | 2,337.93 | 3 | 779.31 | 1,349.80 | 1.73 | 51.96 |
| 72 | 30 Feet Wood | 30 | 779.31 | 1 | 779.31 | 779.31 | 1.00 | 30.00 |
| 73 | 30 Feet Wood | 30 | 779.31 | 1 | 779.31 | 779.31 | 1.00 | 30.00 |
| 74 | 30 Feet Wood | 30 | 4,376.10 | 6 | 729.35 | 1,786.54 | 2.45 | 73.48 |
| 75 | 30 Feet Wood | 30 | 17,073.13 | 23 | 742.31 | 3,559.99 | 4.80 | 143.87 |
| 76 | 30 Feet Wood | 30 | 706,984.04 | 1,049 | 673.96 | 21,828.40 | 32.39 | 971.65 |
| 77 | 30 Feet Wood | 30 | 21,429.66 | 37 | 579.18 | 3,523.01 | 6.08 | 182.48 |
| 78 | 30 Feet Wood | 30 | 3,369.80 | 5 | 673.96 | 1,507.02 | 2.24 | 67.08 |
| 79 | 32 Feet Steel | 32 | 76,446.60 | 12 | 6,370.55 | 22,068.23 | 3.46 | 110.85 |
| 80 | 33 Feet Pine | 33 | 673.96 | 1 | 673.96 | 673.96 | 1.00 | 33.00 |
| 81 | 33 Feet Unknown | 33 | 6,739.60 | 10 | 673.96 | 2,131.25 | 3.16 | 104.36 |
| 82 | 35 Feet Aluminum | 35 | 248,002.46 | 107 | 2,317.78 | 23,975.30 | 10.34 | 362.04 |
| 83 | 35 Feet Cedar | 35 | 2,071.77 | 3 | 690.59 | 1,196.14 | 1.73 | 60.62 |
| 84 | 35 Feet Douglas Fur | 35 | 1,713.20 | 2 | 856.60 | 1,211.42 | 1.41 | 49.50 |
| 85 | 35 Feet Douglas Fur | 35 | 826.61 | 1 | 826.61 | 826.61 | 1.00 | 35.00 |
| 86 | 35 Feet Fiberglass | 35 | 5,776.10 | 1 | 5,776.10 | 5,776.10 | 1.00 | 35.00 |
| 87 | 35 Feet Pine | 35 | 13,427.96 | 14 | 959.14 | 3,588.77 | 3.74 | 130.96 |
| 88 | 35 Feet Pine | 35 | 15,346.24 | 16 | 959.14 | 3,836.56 | 4.00 | 140.00 |
| 89 | 35 Feet Pine | 35 | 431,613.00 | 450 | 959.14 | 20,346.43 | 21.21 | 742.46 |
| 90 | 35 Feet Pine | 35 | 92,313.93 | 97 | 951.69 | 9,373.06 | 9.85 | 344.71 |
| 91 | 35 Feet Pine | 35 | 3,119,737.20 | 3,642 | 856.60 | 51,694.94 | 60.35 | 2,112.21 |
| 92 | 35 Feet Pine | 35 | 26,492,850.50 | 32,050 | 826.61 | 147,983.97 | 179.03 | 6,265.88 |
| 93 | 35 Feet Pine | 35 | 3,743,688.39 | 5,421 | 690.59 | 50,846.37 | 73.63 | 2,576.96 |
| 94 | 35 Feet Pine | 35 | 667,326.20 | 1,028 | 649.15 | 20,813.33 | 32.06 | 1,122.19 |
| 95 | 35 Feet Pine | 35 | 571.26 | 1 | 571.26 | 571.26 | 1.00 | 35.00 |
| 96 | 35 Feet Pine | 35 | 1,381.18 | 2 | 690.59 | 976.64 | 1.41 | 49.50 |
| 97 | 35 Feet Ponderosa Pine | 35 | 959.14 | 1 | 959.14 | 959.14 | 1.00 | 35.00 |
| 98 | 35 Feet Ponderosa Pine | 35 | 8,566.00 | 10 | 856.60 | 2,708.81 | 3.16 | 110.68 |
| 99 | 35 Feet Ponderosa Pine | 35 | 171,934.88 | 208 | 826.61 | 11,921.54 | 14.42 | 504.78 |
| 100 | 35 Feet Ponderosa Pine | 35 | 2,071.77 | 3 | 690.59 | 1,196.14 | 1.73 | 60.62 |
| 101 | 35 Feet Steel | 35 | 12,341.79 | 3 | 4,113.93 | 7,125.54 | 1.73 | 60.62 |
| 102 | 35 Feet Steel | 35 | 4,113.93 | 1 | 4,113.93 | 4,113.93 | 1.00 | 35.00 |
| 103 | 35 Feet Steel | 35 | 209,810.43 | 51 | 4,113.93 | 29,379.34 | 7.14 | 249.95 |
| 104 | 35 Feet Unknown | 35 | 959.14 | 1 | 959.14 | 959.14 | 1.00 | 35.00 |
| 105 | 35 Feet Unknown | 35 | 6,852.80 | 8 | 856.60 | 2,422.83 | 2.83 | 98.99 |
| 106 | 35 Feet Unknown | 35 | 28,931.35 | 35 | 826.61 | 4,890.29 | 5.92 | 207.06 |
| 107 | 35 Feet Unknown | 35 | 2,071.77 | 3 | 690.59 | 1,196.14 | 1.73 | 60.62 |
| 108 | 35 Feet Unknown | 35 | 1,381.18 | 2 | 690.59 | 976.64 | 1.41 | 49.50 |
| 109 | 35 Feet Unknown | 35 | 1,381.18 | 2 | 690.59 | 976.64 | 1.41 | 49.50 |
| 110 | 35 Feet Wood | 35 | 10,550.54 | 11 | 959.14 | 3,181.11 | 3.32 | 116.08 |
| 111 | 35 Feet Wood | 35 | 5,710.14 | 6 | 951.69 | 2,331.15 | 2.45 | 85.73 |
| 112 | 35 Feet Wood | 35 | 99,365.60 | 116 | 856.60 | 9,225.86 | 10.77 | 376.96 |
| 113 | 35 Feet Wood | 35 | 646,409.02 | 782 | 826.61 | 23,115.54 | 27.96 | 978.75 |
| 114 | 35 Feet Wood | 35 | 169,194.55 | 245 | 690.59 | 10,809.44 | 15.65 | 547.84 |
| 115 | 35 Feet Wood | 35 | 18,825.35 | 29 | 649.15 | 3,495.78 | 5.39 | 188.48 |
| 116 | 35 Feet Wood | 35 | 610.21 | 1 | 610.21 | 610.21 | 1.00 | 35.00 |
| 117 | 35 Feet Wood | 35 | 2,479.83 | 3 | 826.61 | 1,431.73 | 1.73 | 60.62 |
| 118 | 37 Feet Steel | 37 | 4,113.93 | 1 | 4,113.93 | 4,113.93 | 1.00 | 37.00 |
| 119 | 40 Feet Cedar | 40 | 4,383.28 | 4 | 1,095.82 | 2,191.64 | 2.00 | 80.00 |
| 120 | 40 Feet Cedar | 40 | 4,466.24 | 4 | 1,116.56 | 2,233.12 | 2.00 | 80.00 |
| 121 | 40 Feet Cedar | 40 | 2,055.38 | 2 | 1,027.69 | 1,453.37 | 1.41 | 56.57 |
| 122 | 40 Feet Concrete | 40 | 1,998.56 | 1 | 1,998.56 | 1,998.56 | 1.00 | 40.00 |
| 123 | 40 Feet Douglas Fur | 40 | 1,027.69 | 1 | 1,027.69 | 1,027.69 | 1.00 | 40.00 |
| 124 | 40 Feet Douglas Fur | 40 | 952.06 | 1 | 952.06 | 952.06 | 1.00 | 40.00 |
| 125 | 40 Feet Douglas Fur | 40 | 952.06 | 1 | 952.06 | 952.06 | 1.00 | 40.00 |
| 126 | 40 Feet Fiberglass | 40 | 11,271.72 | 6 | 1,878.62 | 4,601.66 | 2.45 | 97.98 |
| 127 | 40 Feet Pine | 40 | 12,054.02 | 11 | 1,095.82 | 3,634.42 | 3.32 | 132.66 |
| 128 | 40 Feet Pine | 40 | 29,587.14 | 27 | 1,095.82 | 5,694.05 | 5.20 | 207.85 |
| 129 | 40 Feet Pine | 40 | 3,049,325.36 | 2,731 | 1,116.56 | 58,350.28 | 52.26 | 2,090.36 |
| 130 | 40 Feet Pine | 40 | 369,263.36 | 344 | 1,073.44 | 19,909.35 | 18.55 | 741.89 |
| 131 | 40 Feet Pine | 40 | 31,465,812.42 | 30,618 | 1,027.69 | 179,825.20 | 174.98 | 6,999.20 |
| 132 | 40 Feet Pine | 40 | 19,556,264.46 | 20,541 | 952.06 | 136,450.49 | 143.32 | 5,732.85 |
| 133 | 40 Feet Pine | 40 | 689,103.80 | 770 | 894.94 | 24,833.58 | 27.75 | 1,109.95 |
| 134 | 40 Feet Pine | 40 | 45,426.96 | 54 | 841.24 | 6,181.83 | 7.35 | 293.94 |
| 135 | 40 Feet Pine | 40 | 1,324.54 | 1 | 1,324.54 | 1,324.54 | 1.00 | 40.00 |
| 136 | 40 Feet Pine | 40 | 1,396.40 | 1 | 1,396.40 | 1,396.40 | 1.00 | 40.00 |
| 137 | 40 Feet Pine | 40 | 7,193.83 | 7 | 1,027.69 | 2,719.01 | 2.65 | 105.83 |
| 138 | 40 Feet Ponderosa Pine | 40 | 3,349.68 | 3 | 1,116.56 | 1,933.94 | 1.73 | 69.28 |
| 139 | 40 Feet Ponderosa Pine | 40 | 229,174.87 | 223 | 1,027.69 | 15,346.68 | 14.93 | 597.33 |
| 140 | 40 Feet Ponderosa Pine | 40 | 158,994.02 | 167 | 952.06 | 12,303.33 | 12.92 | 516.91 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 141 | 40 Feet Steel | 40 | 2,226.92 | 1 | 2,226.92 | 2,226.92 | 1.00 | 40.00 |
| 142 | 40 Feet Steel | 40 | 438,703.24 | 197 | 2,226.92 | 31,256.31 | 14.04 | 561.43 |
| 143 | 40 Feet Unknown | 40 | 1,183.55 | 1 | 1,183.55 | 1,183.55 | 1.00 | 40.00 |
| 144 | 40 Feet Unknown | 40 | 4,466.24 | 4 | 1,116.56 | 2,233.12 | 2.00 | 80.00 |
| 145 | 40 Feet Unknown | 40 | 26,719.94 | 26 | 1,027.69 | 5,240.21 | 5.10 | 203.96 |
| 146 | 40 Feet Unknown | 40 | 14,280.90 | 15 | 952.06 | 3,687.31 | 3.87 | 154.92 |
| 147 | 40 Feet Unknown | 40 | 952.06 | 1 | 952.06 | 952.06 | 1.00 | 40.00 |
| 148 | 40 Feet Unknown | 40 | 13,359.97 | 13 | 1,027.69 | 3,705.39 | 3.61 | 144.22 |
| 149 | 40 Feet Wood | 40 | 88,208.24 | 79 | 1,116.56 | 9,924.20 | 8.89 | 355.53 |
| 150 | 40 Feet Wood | 40 | 12,881.28 | 12 | 1,073.44 | 3,718.51 | 3.46 | 138.56 |
| 151 | 40 Feet Wood | 40 | 718,355.31 | 699 | 1,027.69 | 27,170.69 | 26.44 | 1,057.54 |
| 152 | 40 Feet Wood | 40 | 642,640.50 | 675 | 952.06 | 24,735.24 | 25.98 | 1,039.23 |
| 153 | 40 Feet Wood | 40 | - | 68 | - | - | 8.25 | 329.85 |
| 154 | 40 Feet Wood | 40 | - | 2 | - | - | 1.41 | 56.57 |
| 155 | 40 Feet Wood | 40 | 2,055.38 | 2 | 1,027.69 | 1,453.37 | 1.41 | 56.57 |
| 156 | 45 Feet Cedar | 45 | 2,642.88 | 2 | 1,321.44 | 1,868.80 | 1.41 | 63.64 |
| 157 | 45 Feet Cedar | 45 | 1,160.08 | 1 | 1,160.08 | 1,160.08 | 1.00 | 45.00 |
| 158 | 45 Feet Cedar | 45 | 1,493.96 | 1 | 1,493.96 | 1,493.96 | 1.00 | 45.00 |
| 159 | 45 Feet Concrete | 45 | 1,998.56 | 1 | 1,998.56 | 1,998.56 | 1.00 | 45.00 |
| 160 | 45 Feet Concrete | 45 | 3,997.12 | 2 | 1,998.56 | 2,826.39 | 1.41 | 63.64 |
| 161 | 45 Feet Pine | 45 | 22,350.41 | 17 | 1,314.73 | 5,420.77 | 4.12 | 185.54 |
| 162 | 45 Feet Pine | 45 | 89,401.64 | 68 | 1,314.73 | 10,841.54 | 8.25 | 371.08 |
| 163 | 45 Feet Pine | 45 | 8,778,325.92 | 6,643 | 1,321.44 | 107,703.44 | 81.50 | 3,667.71 |
| 164 | 45 Feet Pine | 45 | 722,099.40 | 660 | 1,094.09 | 28,107.68 | 25.69 | 1,156.07 |
| 165 | 45 Feet Pine | 45 | 39,276,828.56 | 33,857 | 1,160.08 | 213,457.87 | 184.00 | 8,280.12 |
| 166 | 45 Feet Pine | 45 | 3,906,859.68 | 3,792 | 1,030.29 | 63,444.45 | 61.58 | 2,771.06 |
| 167 | 45 Feet Pine | 45 | 94,534.72 | 98 | 964.64 | 9,549.45 | 9.90 | 445.48 |
| 168 | 45 Feet Pine | 45 | 4,533.85 | 5 | 906.77 | 2,027.60 | 2.24 | 100.62 |
| 169 | 45 Feet Pine | 45 | 1,493.96 | 1 | 1,493.96 | 1,493.96 | 1.00 | 45.00 |
| 170 | 45 Feet Ponderosa Pine | 45 | 33,036.00 | 25 | 1,321.44 | 6,607.20 | 5.00 | 225.00 |
| 171 | 45 Feet Ponderosa Pine | 45 | 1,094.09 | 1 | 1,094.09 | 1,094.09 | 1.00 | 45.00 |
| 172 | 45 Feet Ponderosa Pine | 45 | 232,016.00 | 200 | 1,160.08 | 16,406.01 | 14.14 | 636.40 |
| 173 | 45 Feet Ponderosa Pine | 45 | 11,333.19 | 11 | 1,030.29 | 3,417.09 | 3.32 | 149.25 |
| 174 | 45 Feet Steel | 45 | 28,174.26 | 6 | 4,695.71 | 11,502.09 | 2.45 | 110.23 |
| 175 | 45 Feet Unknown | 45 | 54,350.79 | 39 | 1,393.61 | 8,703.09 | 6.24 | 281.02 |
| 176 | 45 Feet Unknown | 45 | 13,147.30 | 10 | 1,314.73 | 4,157.54 | 3.16 | 142.30 |
| 177 | 45 Feet Unknown | 45 | 2,642.88 | 2 | 1,321.44 | 1,868.80 | 1.41 | 63.64 |
| 178 | 45 Feet Unknown | 45 | 44,857.69 | 41 | 1,094.09 | 7,005.59 | 6.40 | 288.14 |
| 179 | 45 Feet Unknown | 45 | 10,440.72 | 9 | 1,160.08 | 3,480.24 | 3.00 | 135.00 |
| 180 | 45 Feet Unknown | 45 | 6,181.74 | 6 | 1,030.29 | 2,523.68 | 2.45 | 110.23 |
| 181 | 45 Feet Wood | 45 | 3,944.19 | 3 | 1,314.73 | 2,277.18 | 1.73 | 77.94 |
| 182 | 45 Feet Wood | 45 | 199,838.96 | 152 | 1,314.73 | 16,209.08 | 12.33 | 554.80 |
| 183 | 45 Feet Wood | 45 | 9,250.08 | 7 | 1,321.44 | 3,496.20 | 2.65 | 119.06 |
| 184 | 45 Feet Wood | 45 | 653,171.73 | 597 | 1,094.09 | 26,732.54 | 24.43 | 1,099.51 |
| 185 | 45 Feet Wood | 45 | 203,014.00 | 175 | 1,160.08 | 15,346.42 | 13.23 | 595.29 |
| 186 | 45 Feet Wood | 45 | 1,030.29 | 1 | 1,030.29 | 1,030.29 | 1.00 | 45.00 |
| 187 | 45 Feet Wood | 45 | 964.64 | 1 | 964.64 | 964.64 | 1.00 | 45.00 |
| 188 | 45 Feet Wood | 45 | 6,960.48 | 6 | 1,160.08 | 2,841.60 | 2.45 | 110.23 |
| 189 | 50 Feet Cedar | 50 | 1,507.52 | 1 | 1,507.52 | 1,507.52 | 1.00 | 50.00 |
| 190 | 50 Feet Cedar | 50 | 17,178.72 | 13 | 1,321.44 | 4,764.52 | 3.61 | 180.28 |
| 191 | 50 Feet Cedar | 50 | 2,188.18 | 2 | 1,094.09 | 1,547.28 | 1.41 | 70.71 |
| 192 | 50 Feet Cedar | 50 | 6,960.48 | 6 | 1,160.08 | 2,841.60 | 2.45 | 122.47 |
| 193 | 50 Feet Douglas Fur | 50 | 5,656.32 | 4 | 1,414.08 | 2,828.16 | 2.00 | 100.00 |
| 194 | 50 Feet Douglas Fur | 50 | 1,084.55 | 1 | 1,084.55 | 1,084.55 | 1.00 | 50.00 |
| 195 | 50 Feet Pine | 50 | 179,394.88 | 119 | 1,507.52 | 16,445.10 | 10.91 | 545.44 |
| 196 | 50 Feet Pine | 50 | 12,923,277.12 | 9,139 | 1,414.08 | 135,183.39 | 95.60 | 4,779.91 |
| 197 | 50 Feet Pine | 50 | 2,249,786.16 | 1,578 | 1,425.72 | 56,635.37 | 39.72 | 1,986.20 |
| 198 | 50 Feet Pine | 50 | 4,332,241.29 | 3,341 | 1,296.69 | 74,950.48 | 57.80 | 2,890.07 |
| 199 | 50 Feet Pine | 50 | 45,633.51 | 39 | 1,170.09 | 7,307.21 | 6.24 | 312.25 |
| 200 | 50 Feet Pine | 50 | 2,169.10 | 2 | 1,084.55 | 1,533.79 | 1.41 | 70.71 |
| 201 | 50 Feet Pine | 50 | 2,038.94 | 2 | 1,019.47 | 1,441.75 | 1.41 | 70.71 |
| 202 | 50 Feet Pine | 50 | 3,412.64 | 2 | 1,706.32 | 2,413.10 | 1.41 | 70.71 |
| 203 | 50 Feet Pine | 50 | 1,614.02 | 1 | 1,614.02 | 1,614.02 | 1.00 | 50.00 |
| 204 | 50 Feet Pine | 50 | 1,296.69 | 1 | 1,296.69 | 1,296.69 | 1.00 | 50.00 |
| 205 | 50 Feet Ponderosa Pine | 50 | 55,149.12 | 39 | 1,414.08 | 8,830.93 | 6.24 | 312.25 |
| 206 | 50 Feet Ponderosa Pine | 50 | 7,128.60 | 5 | 1,425.72 | 3,188.01 | 2.24 | 111.80 |
| 207 | 50 Feet Ponderosa Pine | 50 | 28,527.18 | 22 | 1,296.69 | 6,082.02 | 4.69 | 234.52 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 208 | 50 Feet Ponderosa Pine | 50 | 1,170.09 | 1 | 1,170.09 | 1,170.09 | 1.00 | 50.00 |
| 209 | 50 Feet Ponderosa Pine | 50 | 1,019.47 | 1 | 1,019.47 | 1,019.47 | 1.00 | 50.00 |
| 210 | 50 Feet Steel | 50 | 23,234.85 | 5 | 4,646.97 | 10,390.94 | 2.24 | 111.80 |
| 211 | 50 Feet Unknown | 50 | 31,109.76 | 22 | 1,414.08 | 6,632.62 | 4.69 | 234.52 |
| 212 | 50 Feet Unknown | 50 | 1,296.69 | 1 | 1,296.69 | 1,296.69 | 1.00 | 50.00 |
| 213 | 50 Feet Wood | 50 | 1,597.97 | 1 | 1,597.97 | 1,597.97 | 1.00 | 50.00 |
| 214 | 50 Feet Wood | 50 | 7,537.60 | 5 | 1,507.52 | 3,370.92 | 2.24 | 111.80 |
| 215 | 50 Feet Wood | 50 | 270,089.28 | 191 | 1,414.08 | 19,542.97 | 13.82 | 691.01 |
| 216 | 50 Feet Wood | 50 | 9,980.04 | 7 | 1,425.72 | 3,772.10 | 2.65 | 132.29 |
| 217 | 50 Feet Wood | 50 | 125,778.93 | 97 | 1,296.69 | 12,770.92 | 9.85 | 492.44 |
| 218 | 50 Feet Wood | 50 | 1,170.09 | 1 | 1,170.09 | 1,170.09 | 1.00 | 50.00 |
| 219 | 50 Feet Wood | 50 | 2,169.10 | 2 | 1,084.55 | 1,533.79 | 1.41 | 70.71 |
| 220 | 50 Feet Wood | 50 | 1,296.69 | 1 | 1,296.69 | 1,296.69 | 1.00 | 50.00 |
| 221 | 55 Feet Cedar | 55 | 4,522.56 | 3 | 1,507.52 | 2,611.10 | 1.73 | 95.26 |
| 222 | 55 Feet Cedar | 55 | 12,726.72 | 9 | 1,414.08 | 4,242.24 | 3.00 | 165.00 |
| 223 | 55 Feet Cedar | 55 | 5,702.88 | 4 | 1,425.72 | 2,851.44 | 2.00 | 110.00 |
| 224 | 55 Feet Concrete | 55 | 2,238.39 | 1 | 2,238.39 | 2,238.39 | 1.00 | 55.00 |
| 225 | 55 Feet Douglas Fur | 55 | 1,840.85 | 1 | 1,840.85 | 1,840.85 | 1.00 | 55.00 |
| 226 | 55 Feet Pine | 55 | 1,951.30 | 1 | 1,951.30 | 1,951.30 | 1.00 | 55.00 |
| 227 | 55 Feet Pine | 55 | 150,949.70 | 82 | 1,840.85 | 16,669.61 | 9.06 | 498.05 |
| 228 | 55 Feet Pine | 55 | 7,345,659.50 | 4,450 | 1,650.71 | 110,116.09 | 66.71 | 3,668.96 |
| 229 | 55 Feet Pine | 55 | 328,608.54 | 234 | 1,404.31 | 21,481.81 | 15.30 | 841.34 |
| 230 | 55 Feet Pine | 55 | 400,413.79 | 287 | 1,395.17 | 23,635.68 | 16.94 | 931.76 |
| 231 | 55 Feet Pine | 55 | 24,626.47 | 19 | 1,296.13 | 5,649.70 | 4.36 | 239.74 |
| 232 | 55 Feet Pine | 55 | 3,655.08 | 3 | 1,218.36 | 2,110.26 | 1.73 | 95.26 |
| 233 | 55 Feet Pine | 55 | 11,674.38 | 6 | 1,945.73 | 4,766.05 | 2.45 | 134.72 |
| 234 | 55 Feet Pine | 55 | 2,161.76 | 1 | 2,161.76 | 2,161.76 | 1.00 | 55.00 |
| 235 | 55 Feet Pine | 55 | 1,650.71 | 1 | 1,650.71 | 1,650.71 | 1.00 | 55.00 |
| 236 | 55 Feet Pine | 55 | 1,650.71 | 1 | 1,650.71 | 1,650.71 | 1.00 | 55.00 |
| 237 | 55 Feet Ponderosa Pine | 55 | 46,219.88 | 28 | 1,650.71 | 8,734.74 | 5.29 | 291.03 |
| 238 | 55 Feet Ponderosa Pine | 55 | 2,808.62 | 2 | 1,404.31 | 1,985.99 | 1.41 | 77.78 |
| 239 | 55 Feet Ponderosa Pine | 55 | 1,395.17 | 1 | 1,395.17 | 1,395.17 | 1.00 | 55.00 |
| 240 | 55 Feet Ponderosa Pine | 55 | 1,170.09 | 1 | 1,170.09 | 1,170.09 | 1.00 | 55.00 |
| 241 | 55 Feet Steel | 55 | 7,109.07 | 3 | 2,369.69 | 4,104.42 | 1.73 | 95.26 |
| 242 | 55 Feet Steel | 55 | 2,369.69 | 1 | 2,369.69 | 2,369.69 | 1.00 | 55.00 |
| 243 | 55 Feet Unknown | 55 | 11,554.97 | 7 | 1,650.71 | 4,367.37 | 2.65 | 145.52 |
| 244 | 55 Feet Wood | 55 | 7,363.40 | 4 | 1,840.85 | 3,681.70 | 2.00 | 110.00 |
| 245 | 55 Feet Wood | 55 | 170,023.13 | 103 | 1,650.71 | 16,752.88 | 10.15 | 558.19 |
| 246 | 55 Feet Wood | 55 | 5,617.24 | 4 | 1,404.31 | 2,808.62 | 2.00 | 110.00 |
| 247 | 55 Feet Wood | 55 | 26,508.23 | 19 | 1,395.17 | 6,081.41 | 4.36 | 239.74 |
| 248 | 60 Feet Cedar | 60 | 2,093.67 | 1 | 2,093.67 | 2,093.67 | 1.00 | 60.00 |
| 249 | 60 Feet Cedar | 60 | 97,426.19 | 53 | 1,838.23 | 13,382.52 | 7.28 | 436.81 |
| 250 | 60 Feet Cedar | 60 | 4,885.44 | 3 | 1,628.48 | 2,820.61 | 1.73 | 103.92 |
| 251 | 60 Feet Cedar | 60 | 1,530.77 | 1 | 1,530.77 | 1,530.77 | 1.00 | 60.00 |
| 252 | 60 Feet Douglas Fur | 60 | 11,554.97 | 7 | 1,650.71 | 4,367.37 | 2.65 | 158.75 |
| 253 | 60 Feet Douglas Fur | 60 | 1,530.77 | 1 | 1,530.77 | 1,530.77 | 1.00 | 60.00 |
| 254 | 60 Feet Pine | 60 | 93,883.35 | 51 | 1,840.85 | 13,146.30 | 7.14 | 428.49 |
| 255 | 60 Feet Pine | 60 | 1,373,390.72 | 832 | 1,650.71 | 47,613.76 | 28.84 | 1,730.66 |
| 256 | 60 Feet Pine | 60 | 44,937.92 | 32 | 1,404.31 | 7,943.98 | 5.66 | 339.41 |
| 257 | 60 Feet Pine | 60 | 11,161.36 | 8 | 1,395.17 | 3,946.14 | 2.83 | 169.71 |
| 258 | 60 Feet Pine | 60 | 1,395.17 | 1 | 1,395.17 | 1,395.17 | 1.00 | 60.00 |
| 259 | 60 Feet Pine | 60 | 4,185.51 | 3 | 1,395.17 | 2,416.51 | 1.73 | 103.92 |
| 260 | 60 Feet Pine | 60 | 4,995.22 | 2 | 2,497.61 | 3,532.15 | 1.41 | 84.85 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 261 | 60 Feet Pine | 60 | 2,771.88 | 1 | 2,771.88 | 2,771.88 | 1.00 | 60.00 |
| 262 | 60 Feet Ponderosa Pine | 60 | 8,253.55 | 5 | 1,650.71 | 3,691.10 | 2.24 | 134.16 |
| 263 | 60 Feet Steel | 60 | 2,526.74 | 1 | 2,526.74 | 2,526.74 | 1.00 | 60.00 |
| 264 | 60 Feet Unknown | 60 | 3,301.42 | 2 | 1,650.71 | 2,334.46 | 1.41 | 84.85 |
| 265 | 60 Feet Wood | 60 | 1,951.30 | 1 | 1,951.30 | 1,951.30 | 1.00 | 60.00 |
| 266 | 60 Feet Wood | 60 | 1,840.85 | 1 | 1,840.85 | 1,840.85 | 1.00 | 60.00 |
| 267 | 60 Feet Wood | 60 | 478,705.90 | 290 | 1,650.71 | 28,110.58 | 17.03 | 1,021.76 |
| 268 | 60 Feet Wood | 60 | 47,746.54 | 34 | 1,404.31 | 8,188.46 | 5.83 | 349.86 |
| 269 | 60 Feet Wood | 60 | 9,766.19 | 7 | 1,395.17 | 3,691.27 | 2.65 | 158.75 |
| 270 | 60 Feet Wood | 60 | 2,790.34 | 2 | 1,395.17 | 1,973.07 | 1.41 | 84.85 |
| 271 | 60 Feet Wood | 60 | 1,395.17 | 1 | 1,395.17 | 1,395.17 | 1.00 | 60.00 |
| 272 | 60 Feet Wood | 60 | 2,432.53 | 1 | 2,432.53 | 2,432.53 | 1.00 | 60.00 |
| 273 | 65 Feet Cedar | 65 | 4,630.46 | 2 | 2,315.23 | 3,274.23 | 1.41 | 91.92 |
| 274 | 65 Feet Cedar | 65 | 44,882.88 | 24 | 1,870.12 | 9,161.68 | 4.90 | 318.43 |
| 275 | 65 Feet Cedar | 65 | 1,870.12 | 1 | 1,870.12 | 1,870.12 | 1.00 | 65.00 |
| 276 | 65 Feet Pine | 65 | 46,218.07 | 19 | 2,432.53 | 10,603.15 | 4.36 | 283.33 |
| 277 | 65 Feet Pine | 65 | 625,112.10 | 270 | 2,315.23 | 38,043.11 | 16.43 | 1,068.06 |
| 278 | 65 Feet Pine | 65 | 5,610.36 | 3 | 1,870.12 | 3,239.14 | 1.73 | 112.58 |
| 279 | 65 Feet Pine | 65 | 7,031.64 | 4 | 1,757.91 | 3,515.82 | 2.00 | 130.00 |
| 280 | 65 Feet Pine | 65 | 5,312.16 | 2 | 2,656.08 | 3,756.26 | 1.41 | 91.92 |
| 281 | 65 Feet Pine | 65 | 3,915.50 | 1 | 3,915.50 | 3,915.50 | 1.00 | 65.00 |
| 282 | 65 Feet Ponderosa Pine | 65 | 2,315.23 | 1 | 2,315.23 | 2,315.23 | 1.00 | 65.00 |
| 283 | 65 Feet Steel | 65 | 15,160.44 | 6 | 2,526.74 | 6,189.22 | 2.45 | 159.22 |
| 284 | 65 Feet Wood | 65 | 9,730.12 | 4 | 2,432.53 | 4,865.06 | 2.00 | 130.00 |
| 285 | 65 Feet Wood | 65 | 456,100.31 | 197 | 2,315.23 | 32,495.80 | 14.04 | 912.32 |
| 286 | 65 Feet Wood | 65 | 56,103.60 | 30 | 1,870.12 | 10,243.07 | 5.48 | 356.02 |
| 287 | 65 Feet Wood | 65 | 5,273.73 | 3 | 1,757.91 | 3,044.79 | 1.73 | 112.58 |
| 288 | 65 Feet Wood | 65 | 1,395.17 | 1 | 1,395.17 | 1,395.17 | 1.00 | 65.00 |
| 289 | 65 Feet Wood | 65 | 4,630.46 | 2 | 2,315.23 | 3,274.23 | 1.41 | 91.92 |
| 290 | 70 Feet Cedar | 70 | 14,839.68 | 7 | 2,119.95 | 5,608.87 | 2.65 | 185.20 |
| 291 | 70 Feet Cedar | 70 | 3,108.37 | 2 | 1,554.19 | 2,197.95 | 1.41 | 98.99 |
| 292 | 70 Feet Cedar | 70 | 3,351.27 | 1 | 3,351.27 | 3,351.27 | 1.00 | 70.00 |
| 293 | 70 Feet Pine | 70 | 11,719.76 | 4 | 2,929.94 | 5,859.88 | 2.00 | 140.00 |
| 294 | 70 Feet Pine | 70 | 145,923.52 | 64 | 2,280.06 | 18,240.44 | 8.00 | 560.00 |
| 295 | 70 Feet Pine | 70 | 12,433.48 | 4 | 3,108.37 | 6,216.74 | 2.00 | 140.00 |
| 296 | 70 Feet Pine | 70 | 2,921.87 | 1 | 2,921.87 | 2,921.87 | 1.00 | 70.00 |
| 297 | 70 Feet Wood | 70 | 5,859.88 | 2 | 2,929.94 | 4,143.56 | 1.41 | 98.99 |
| 298 | 70 Feet Wood | 70 | 143,450.24 | 101 | 1,420.30 | 14,273.83 | 10.05 | 703.49 |
| 299 | 70 Feet Wood | 70 | 2,921.87 | 1 | 2,921.87 | 2,921.87 | 1.00 | 70.00 |
| 300 | 75 Feet Cedar | 75 | 7,528.02 | 2 | 3,764.01 | 5,323.11 | 1.41 | 106.07 |
| 301 | 75 Feet Pine | 75 | 10,477.04 | 2 | 5,238.52 | 7,408.39 | 1.41 | 106.07 |
| 302 | 75 Feet Pine | 75 | 86,572.23 | 23 | 3,764.01 | 18,051.56 | 4.80 | 359.69 |
| 303 | 75 Feet Unknown | 75 | 3,764.01 | 1 | 3,764.01 | 3,764.01 | 1.00 | 75.00 |
| 304 | 75 Feet Wood | 75 | 10,477.04 | 2 | 5,238.52 | 7,408.39 | 1.41 | 106.07 |
| 305 | 75 Feet Wood | 75 | 158,088.42 | 42 | 3,764.01 | 24,393.57 | 6.48 | 486.06 |
| 306 | 75 Feet Wood | 75 | 3,312.33 | 1 | 3,312.33 | 3,312.33 | 1.00 | 75.00 |
| 307 | 75 Feet Wood | 75 | 7,528.02 | 2 | 3,764.01 | 5,323.11 | 1.41 | 106.07 |
| 308 | 80 Feet Cedar | 80 | 3,771.74 | 1 | 3,771.74 | 3,771.74 | 1.00 | 80.00 |
| 309 | 80 Feet Douglas Fur | 80 | 3,771.74 | 1 | 3,771.74 | 3,771.74 | 1.00 | 80.00 |
| 310 | 80 Feet Pine | 80 | 7,543.48 | 6 | 1,257.25 | 3,079.61 | 2.45 | 195.96 |
| 311 | 80 Feet Pine | 80 | 3,319.13 | 1 | 3,319.13 | 3,319.13 | 1.00 | 80.00 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 364 - Poles**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 312 | 85 Feet Cedar | 85 | 8,512.34 | 1 | 8,512.34 | 8,512.34 | 1.00 | 85.00 |
| 313 | 85 Feet Pine | 85 | 72,274.59 | 9 | 8,030.51 | 24,091.53 | 3.00 | 255.00 |
| 314 | TOTAL | | $ 208,768,892.28 | 210,115 | | | | |
| 315 | | | | | | | | |
| 316 | **Zero Intercept Linear Regression Results** | | | | | **LINEST Array** | | |
| 317 | | | | | | | | |
| 318 | Size Coefficient ($ per MCM) | | 35.01859 | | | 35.01859 | (386.51047) | |
| 319 | Zero Intercept ($ per Unit) | | (386.51047) | | | 1.14938 | 46.01274 | |
| 320 | R-Square | | 0.9810 | | | 0.98099 | 3,703.78655 | |
| 321 | | | | | | | | |
| 322 | **Plant Classification** | | | | | | | |
| 323 | | | | | | | | |
| 324 | Total Number of Units | | 210,115 | | | | | |
| 325 | Zero Intercept ($/Unit) | | $ (386.51) | | | | | |
| 326 | Minimum System ($/Unit) | | $ - | | | | | |
| 327 | Use Min System (M) or Zero Intercept (Z)? | | Z | | | | | |
| 328 | Zero Intercept or Min System Cost ($) | | $ (81,211,648) | | | | | |
| 329 | Total Cost of Sample | | $ 208,768,892 | | | | | |
| 330 | Percentage of Total | | -0.3890 | | | | | |
| 331 | Percentage Classified as Customer-Related | | -38.90% | | | | | |
| 332 | Percentage Classified as Demand-Related | | 138.90% | | | | | |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 368 - Transformers**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 1 | 34500GRDY/19920V | 100 | $ 119,722.60 | 20 | 5,986.13 | 26,770.79 | 4.47 | 447.21 |
| 2 | 12470GRDY/7200V | 100 | 737,701.52 | 164 | 4,498.18 | 57,604.81 | 12.81 | 1,280.62 |
| 3 | 12470GRDY/7200V | 1000 | 245,405.36 | 8 | 30,675.67 | 86,763.90 | 2.83 | 2,828.43 |
| 4 | 12470GRDY/7200V | 1000 | 604,088.47 | 19 | 31,794.13 | 138,587.40 | 4.36 | 4,358.90 |
| 5 | 34500GRDY/19920V | 1000 | 31,794.13 | 1 | 31,794.13 | 31,794.13 | 1.00 | 1,000.00 |
| 6 | 34500GRDY/19920V | 1000 | 349,735.43 | 11 | 31,794.13 | 105,449.20 | 3.32 | 3,316.62 |
| 7 | 12470GRDY/7200V | 112.5 | 109,569.33 | 13 | 8,428.41 | 30,389.06 | 3.61 | 405.62 |
| 8 | 12470GRDY/7200V | 112.5 | 127,176.52 | 4 | 31,794.13 | 63,588.26 | 2.00 | 225.00 |
| 9 | 34500GRDY/19920V | 112.5 | 165,726.84 | 12 | 13,810.57 | 47,841.22 | 3.46 | 389.71 |
| 10 | 34500GRDY/19920V | 112.5 | 68,408.45 | 5 | 13,681.69 | 30,593.19 | 2.24 | 251.56 |
| 11 | 12470GRDY/7200V | 150 | 463,137.75 | 45 | 10,291.95 | 69,040.50 | 6.71 | 1,006.23 |
| 12 | 12470GRDY/7200V | 150 | 101,004.40 | 10 | 10,100.44 | 31,940.40 | 3.16 | 474.34 |
| 13 | 34500GRDY/19920V | 150 | 158,207.17 | 11 | 14,382.47 | 47,701.26 | 3.32 | 497.49 |
| 14 | 34500GRDY/19920V | 150 | 56,918.76 | 4 | 14,229.69 | 28,459.38 | 2.00 | 300.00 |
| 15 | 12470GRDY/7200V | 1500 | 697,040.48 | 16 | 43,565.03 | 174,260.12 | 4.00 | 6,000.00 |
| 16 | 34500GRDY/19920V | 1500 | 76,912.30 | 2 | 38,456.15 | 54,385.21 | 1.41 | 2,121.32 |
| 17 | 3450GRDY/19920V | 1500 | 230,736.90 | 6 | 38,456.15 | 94,197.94 | 2.45 | 3,674.23 |
| 18 | 3450GRDY/19920V | 167 | 171,687.56 | 22 | 7,803.98 | 36,603.91 | 4.69 | 783.30 |
| 19 | 12470GRDY/7200V | 167 | 456,761.76 | 78 | 5,855.92 | 51,718.09 | 8.83 | 1,474.90 |
| 20 | 12470GRDY/7200V | 225 | 133,681.10 | 10 | 13,368.11 | 42,273.68 | 3.16 | 711.51 |
| 21 | 12470GRDY/7200V | 225 | 49,262.40 | 3 | 16,420.80 | 28,441.66 | 1.73 | 389.71 |
| 22 | 34500GRDY/19920V | 225 | 114,945.60 | 7 | 16,420.80 | 43,445.35 | 2.65 | 595.29 |
| 23 | 34500GRDY/19920V | 225 | 32,841.60 | 2 | 16,420.80 | 23,222.52 | 1.41 | 318.20 |
| 24 | 34500GRDY/19920V | 25 | 107,131.24 | 46 | 2,328.94 | 15,795.64 | 6.78 | 169.56 |
| 25 | 12470GRDY/7200V | 25 | 442,122.99 | 177 | 2,497.87 | 33,232.00 | 13.30 | 332.60 |
| 26 | 12470GRDY/7200V | 250 | 9,207.05 | 1 | 9,207.05 | 9,207.05 | 1.00 | 250.00 |
| 27 | 12470GRDY/7200V | 2500 | 50,379.62 | 1 | 50,379.62 | 50,379.62 | 1.00 | 2,500.00 |
| 28 | 34500GRDY/19920V | 2500 | 52,925.22 | 1 | 52,925.22 | 52,925.22 | 1.00 | 2,500.00 |
| 29 | 12470GRDY/7200V | 300 | 807,494.75 | 53 | 15,235.75 | 110,917.93 | 7.28 | 2,184.03 |
| 30 | 12470GRDY/7200V | 300 | 227,869.92 | 16 | 14,241.87 | 56,967.48 | 4.00 | 1,200.00 |
| 31 | 34500GRDY/19920V | 300 | 314,492.96 | 16 | 19,655.81 | 78,623.24 | 4.00 | 1,200.00 |
| 32 | 34500GRDY/19920V | 300 | 130,501.91 | 7 | 18,643.13 | 49,325.09 | 2.65 | 793.73 |
| 33 | 34500GRDY/19920V | 50 | 427,638.90 | 94 | 4,549.35 | 44,107.58 | 9.70 | 484.77 |
| 34 | 12470GRDY/7200V | 50 | 1,337,197.50 | 450 | 2,971.55 | 63,036.09 | 21.21 | 1,060.66 |
| 35 | 12470GRDY/7200V | 500 | 1,084,893.15 | 55 | 19,725.33 | 146,286.96 | 7.42 | 3,708.10 |
| 36 | 12470GRDY/7200V | 500 | 1,017,430.80 | 60 | 16,957.18 | 131,349.75 | 7.75 | 3,872.98 |
| 37 | 12470GRDY/7200V | 500 | 50,871.54 | 3 | 16,957.18 | 29,370.70 | 1.73 | 866.03 |
| 38 | 34500GRDY/19920V | 500 | 372,411.01 | 17 | 21,906.53 | 90,322.94 | 4.12 | 2,061.55 |
| 39 | 34500GRDY/19920V | 500 | 21,255.21 | 1 | 21,255.21 | 21,255.21 | 1.00 | 500.00 |
| 40 | 3450GRDY/19920V | 500 | 552,635.46 | 26 | 21,255.21 | 108,380.73 | 5.10 | 2,549.51 |
| 41 | 3450GRDY/19920V | 75 | 208,375.20 | 40 | 5,209.38 | 32,947.01 | 6.32 | 474.34 |
| 42 | 12470GRDY/7200V | 75 | 396,551.30 | 106 | 3,741.05 | 38,516.47 | 10.30 | 772.17 |
| 43 | 12470GRDY/7200V | 750 | 448,073.25 | 17 | 26,357.25 | 108,673.73 | 4.12 | 3,092.33 |
| 44 | 12470GRDY/7200V | 750 | 990,591.42 | 39 | 25,399.78 | 158,621.58 | 6.24 | 4,683.75 |
| 45 | 34500GRDY/19920V | 750 | 30,892.76 | 1 | 30,892.76 | 30,892.76 | 1.00 | 750.00 |
| 46 | 34500GRDY/19920V | 750 | 61,785.52 | 2 | 30,892.76 | 43,688.96 | 1.41 | 1,060.66 |
| 47 | 34500GRDY/19920V | 750 | 116,347.32 | 4 | 29,086.83 | 58,173.66 | 2.00 | 1,500.00 |
| 48 | 3450GRDY/19920V | 750 | 261,781.47 | 9 | 29,086.83 | 87,260.49 | 3.00 | 2,250.00 |
| 49 | 12470GRDY/7200V | 100 | 44,981.80 | 10 | 4,498.18 | 14,224.49 | 3.16 | 316.23 |
| 50 | 12470GRDY/7200V | 1000 | 30,675.67 | 1 | 30,675.67 | 30,675.67 | 1.00 | 1,000.00 |
| 51 | 12470GRDY/7200V | 1000 | 31,794.13 | 1 | 31,794.13 | 31,794.13 | 1.00 | 1,000.00 |
| 52 | 12470GRDY/7200V | 150 | 51,459.75 | 5 | 10,291.95 | 23,013.50 | 2.24 | 335.41 |
| 53 | 12470GRDY/7200V | 150 | 10,291.95 | 1 | 10,291.95 | 10,291.95 | 1.00 | 150.00 |
| 54 | 34500GRDY/19920V | 150 | 10,100.44 | 1 | 10,100.44 | 10,100.44 | 1.00 | 150.00 |
| 55 | 12470GRDY/7200V | 150 | 10,291.95 | 1 | 10,291.95 | 10,291.95 | 1.00 | 150.00 |
| 56 | 12470GRDY/7200V | 300 | 45,707.25 | 3 | 15,235.75 | 26,389.09 | 1.73 | 519.62 |
| 57 | 12470GRDY/7200V | 300 | 28,483.74 | 2 | 14,241.87 | 20,141.05 | 1.41 | 424.26 |
| 58 | 12470GRDY/7200V | 300 | 76,178.75 | 5 | 15,235.75 | 34,068.17 | 2.24 | 670.82 |
| 59 | 34500GRDY/19920V | 300 | 39,311.62 | 2 | 19,655.81 | 27,797.51 | 1.41 | 424.26 |
| 60 | 12470GRDY/7200V | 500 | 78,901.32 | 4 | 19,725.33 | 39,450.66 | 2.00 | 1,000.00 |
| 61 | 12470GRDY/7200V | 500 | 101,743.08 | 6 | 16,957.18 | 41,536.44 | 2.45 | 1,224.74 |
| 62 | 12470GRDY/7200V | 500 | 16,957.18 | 1 | 16,957.18 | 16,957.18 | 1.00 | 500.00 |
| 63 | 12470GRDY/7200V | 500 | 19,725.33 | 1 | 19,725.33 | 19,725.33 | 1.00 | 500.00 |
| 64 | 34500GRDY/19920V | 500 | 65,719.59 | 3 | 21,906.53 | 37,943.22 | 1.73 | 866.03 |
| 65 | 34500GRDY/19920V | 500 | 42,510.42 | 2 | 21,255.21 | 30,059.41 | 1.41 | 707.11 |
| 66 | 12470GRDY/7200V | 75 | 7,482.10 | 2 | 3,741.05 | 5,290.64 | 1.41 | 106.07 |
| 67 | 12470GRDY/7200V | 75 | 74,821.00 | 20 | 3,741.05 | 16,730.48 | 4.47 | 335.41 |
| 68 | 12470GRDY/7200V | 750 | 52,714.50 | 2 | 26,357.25 | 37,274.78 | 1.41 | 1,060.66 |
| 69 | 12470GRDY/7200V | 750 | 25,399.78 | 1 | 25,399.78 | 25,399.78 | 1.00 | 750.00 |
| 70 | 12470GRDY/7200V | 750 | 50,799.56 | 2 | 25,399.78 | 35,920.71 | 1.41 | 1,060.66 |
| 71 | 12470GRDY/7200V | 750 | 25,399.78 | 1 | 25,399.78 | 25,399.78 | 1.00 | 750.00 |
| 72 | 34500GRDY/19920V | 112.5 | 13,810.57 | 1 | 13,810.57 | 13,810.57 | 1.00 | 112.50 |
| 73 | 12470GRDY/7200V | 50 | 13,648.05 | 3 | 4,549.35 | 7,879.71 | 1.73 | 86.60 |
| 74 | 34500GRDY/19920V | 5000 | 243,802.32 | 3 | 81,267.44 | 140,759.34 | 1.73 | 8,660.25 |
| 75 | 12470GRDY/7200V | 75 | 3,741.05 | 1 | 3,741.05 | 3,741.05 | 1.00 | 75.00 |
| 76 | 12470GRDY/7200V | 75 | 7,482.10 | 2 | 3,741.05 | 5,290.64 | 1.41 | 106.07 |
| 77 | 12470GRDY/7200V | 1.5 | 1,371.72 | 2 | 685.86 | 969.95 | 1.41 | 2.12 |
| 78 | 1247GRDY/7200V | 1.5 | 8,242.32 | 12 | 686.86 | 2,379.35 | 3.46 | 5.20 |
| 79 | 1247GRDY/7200V | 1.5 | 1,373.72 | 2 | 686.86 | 971.37 | 1.41 | 2.12 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 368 - Transformers**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 80 | 34500GRDY/19920V | 1.5 | 1,167.96 | 1 | 1,167.96 | 1,167.96 | 1.00 | 1.50 |
| 81 | 34500GRDY/19920V | 1.5 | 8,175.72 | 7 | 1,167.96 | 3,090.13 | 2.65 | 3.97 |
| 82 | 12470GRDY/7200V | 1.5 | 686.86 | 1 | 686.86 | 686.86 | 1.00 | 1.50 |
| 83 | 12470GRDY/7200V | 10 | 8,512,197.37 | 5,699 | 1,493.63 | 112,756.70 | 75.49 | 754.92 |
| 84 | 12470GRDY/7200V | 10 | 47,796.16 | 32 | 1,493.63 | 8,449.25 | 5.66 | 56.57 |
| 85 | 1247GRDY/7200V | 10 | 2,987.26 | 2 | 1,493.63 | 2,112.31 | 1.41 | 14.14 |
| 86 | 34500GRDY/19920V | 10 | 14,126.50 | 10 | 1,412.65 | 4,467.19 | 3.16 | 31.62 |
| 87 | 34500GRDY/19920V | 10 | 2,825.30 | 2 | 1,412.65 | 1,997.79 | 1.41 | 14.14 |
| 88 | 34500GRDY/19920V | 10 | 4,237.95 | 3 | 1,412.65 | 2,446.78 | 1.73 | 17.32 |
| 89 | 34500GRDY/19920V | 10 | 22,602.40 | 16 | 1,412.65 | 5,650.60 | 4.00 | 40.00 |
| 90 | 1247GRDY/7200V | 10 | 4,480.89 | 3 | 1,493.63 | 2,587.04 | 1.73 | 17.32 |
| 91 | 34500GRDY/19920V | 10 | 2,746,191.60 | 1,944 | 1,412.65 | 62,284.89 | 44.09 | 440.91 |
| 92 | 34500GRDY/19920V | 10 | 24,377.58 | 18 | 1,354.31 | 5,745.85 | 4.24 | 42.43 |
| 93 | 1247GRDY/7200V | 10 | 2,987.26 | 2 | 1,493.63 | 2,112.31 | 1.41 | 14.14 |
| 94 | 1247GRDY/7200V | 10 | 2,195,636.10 | 1,470 | 1,493.63 | 57,266.64 | 38.34 | 383.41 |
| 95 | 1247GRDY/7200V | 10 | 8,961.78 | 6 | 1,493.63 | 3,658.63 | 2.45 | 24.49 |
| 96 | 1247GRDY/7200V | 100 | 3,486.42 | 1 | 3,486.42 | 3,486.42 | 1.00 | 100.00 |
| 97 | 12470GRDY/7200V | 100 | 10,459.26 | 3 | 3,486.42 | 6,038.66 | 1.73 | 173.21 |
| 98 | 12470GRDY/7200V | 100 | 622,755.00 | 210 | 2,965.50 | 42,974.18 | 14.49 | 1,449.14 |
| 99 | 1247GRDY/7200V | 100 | 128,997.54 | 37 | 3,486.42 | 21,207.06 | 6.08 | 608.28 |
| 100 | 34500GRDY/19920V | 100 | 485,007.40 | 124 | 3,911.35 | 43,554.95 | 11.14 | 1,113.55 |
| 101 | 34500GRDY/19920V | 100 | 45,201.52 | 14 | 3,228.68 | 12,080.61 | 3.74 | 374.17 |
| 102 | 34500GRDY/19920V | 100 | 9,978.66 | 2 | 4,989.33 | 7,055.98 | 1.41 | 141.42 |
| 103 | 12470GRDY/7200V | 100 | 3,486.42 | 1 | 3,486.42 | 3,486.42 | 1.00 | 100.00 |
| 104 | 12470GRDY/7200V | 100 | 45,323.46 | 13 | 3,486.42 | 12,570.47 | 3.61 | 360.56 |
| 105 | 34500GRDY/19920V | 100 | 829,206.20 | 212 | 3,911.35 | 56,950.12 | 14.56 | 1,456.02 |
| 106 | 34500GRDY/19920V | 100 | 370,687.50 | 125 | 2,965.50 | 33,155.30 | 11.18 | 1,118.03 |
| 107 | 34500GRDY/19920V | 100 | 2,030.53 | 1 | 2,030.53 | 2,030.53 | 1.00 | 100.00 |
| 108 | 12470GRDY/7200V | 100 | 6,972.84 | 2 | 3,486.42 | 4,930.54 | 1.41 | 141.42 |
| 109 | 12470GRDY/7200V | 100 | 3,817,629.90 | 1,095 | 3,486.42 | 115,368.37 | 33.09 | 3,309.08 |
| 110 | 12470GRDY/7200V | 100 | 119,461.16 | 37 | 3,228.68 | 19,639.29 | 6.08 | 608.28 |
| 111 | 12470GRDY/7200V | 100 | 29,655.00 | 10 | 2,965.50 | 9,377.73 | 3.16 | 316.23 |
| 112 | 12470GRDY/7200V | 15 | 2,464.82 | 2 | 1,232.41 | 1,742.89 | 1.41 | 21.21 |
| 113 | 12470GRDY/7200V | 15 | 19,660,636.73 | 15,953 | 1,232.41 | 155,659.77 | 126.31 | 1,894.58 |
| 114 | 12470GRDY/7200V | 15 | 189,523.18 | 154 | 1,230.67 | 15,272.21 | 12.41 | 186.15 |
| 115 | 34500GRDY/19920V | 15 | 114,019.20 | 64 | 1,781.55 | 14,252.40 | 8.00 | 120.00 |
| 116 | 34500GRDY/19920V | 15 | 2,147.48 | 2 | 1,073.74 | 1,518.50 | 1.41 | 21.21 |
| 117 | 12470GRDY/7200V | 15 | 16,021.33 | 13 | 1,232.41 | 4,443.52 | 3.61 | 54.08 |
| 118 | 34500GRDY/19920V | 15 | 7,435,290.14 | 4,978 | 1,493.63 | 105,382.98 | 70.55 | 1,058.32 |
| 119 | 34500GRDY/19920V | 15 | 68,787.02 | 46 | 1,495.37 | 10,142.09 | 6.78 | 101.73 |
| 120 | 34500GRDY/19920V | 15 | 7,468.15 | 5 | 1,493.63 | 3,339.86 | 2.24 | 33.54 |
| 121 | 12470GRDY/7200V | 15 | 13,556.51 | 11 | 1,232.41 | 4,087.44 | 3.32 | 49.75 |
| 122 | 12470GRDY/7200V | 15 | 3,082,212.51 | 2,301 | 1,339.51 | 64,254.61 | 47.97 | 719.53 |
| 123 | 12470GRDY/7200V | 15 | 41,125.80 | 30 | 1,370.86 | 7,508.51 | 5.48 | 82.16 |
| 124 | 12470GRDY/7200V | 167 | 715,531.52 | 128 | 5,590.09 | 63,244.65 | 11.31 | 1,889.39 |
| 125 | 34500GRDY/19920V | 167 | 264,409.20 | 45 | 5,875.76 | 39,415.80 | 6.71 | 1,120.27 |
| 126 | 34500GRDY/19920V | 167 | 89,807.94 | 18 | 4,989.33 | 21,167.93 | 4.24 | 708.52 |
| 127 | 12470GRDY/7200V | 167 | 13,776.95 | 5 | 2,755.39 | 6,161.24 | 2.24 | 373.42 |
| 128 | 34500GRDY/19920V | 167 | 240,906.16 | 41 | 5,875.76 | 37,623.22 | 6.40 | 1,069.32 |
| 129 | 34500GRDY/19920V | 167 | 305,730.17 | 61 | 5,011.97 | 39,144.74 | 7.81 | 1,304.31 |
| 130 | 34500GRDY/19920V | 167 | 468,997.02 | 94 | 4,989.33 | 48,373.35 | 9.70 | 1,619.13 |
| 131 | 12470GRDY/7200V | 167 | 537,301.05 | 195 | 2,755.39 | 38,476.93 | 13.96 | 2,332.03 |
| 132 | 12470GRDY/7200V | 167 | 120,964.20 | 28 | 4,320.15 | 22,860.09 | 5.29 | 883.68 |
| 133 | 12470GRDY/7200V | 167 | 41,925.60 | 15 | 2,795.04 | 10,825.14 | 3.87 | 646.79 |
| 134 | 12470GRDY/7200V | 167 | 17,280.58 | 2 | 8,640.29 | 12,219.22 | 1.41 | 236.17 |
| 135 | 12470GRDY/7200V | 167 | 2,755.39 | 1 | 2,755.39 | 2,755.39 | 1.00 | 167.00 |
| 136 | 12470GRDY/7200V | 25 | 7,381.10 | 5 | 1,476.22 | 3,300.93 | 2.24 | 55.90 |
| 137 | 12470GRDY/7200V | 25 | 41,343,017.32 | 28,006 | 1,476.22 | 247,045.32 | 167.35 | 4,183.75 |
| 138 | 12470GRDY/7200V | 25 | 587,389.44 | 409 | 1,436.16 | 29,044.54 | 20.22 | 505.59 |
| 139 | 1247GRDY/ 7200V | 25 | 2,952.44 | 2 | 1,476.22 | 2,087.69 | 1.41 | 35.36 |
| 140 | 1247GRDY/ 7200V | 25 | 1,476.22 | 1 | 1,476.22 | 1,476.22 | 1.00 | 25.00 |
| 141 | 34500GRDY/19920V | 25 | 364,029.84 | 204 | 1,784.46 | 25,487.19 | 14.28 | 357.07 |
| 142 | 34500GRDY/19920V | 25 | 1,928.57 | 1 | 1,928.57 | 1,928.57 | 1.00 | 25.00 |
| 143 | 34500GRDY/19920V | 25 | 5,353.38 | 3 | 1,784.46 | 3,090.78 | 1.73 | 43.30 |
| 144 | 34500GRDY/19920V | 25 | 25,071.41 | 13 | 1,928.57 | 6,953.56 | 3.61 | 90.14 |
| 145 | 12470GRDY/ 7200V | 25 | 41,334.16 | 28 | 1,476.22 | 7,811.42 | 5.29 | 132.29 |
| 146 | 12470GRDY/ 7200V | 25 | 1,476.22 | 1 | 1,476.22 | 1,476.22 | 1.00 | 25.00 |
| 147 | 34500GRDY/19920V | 25 | 1,784.46 | 1 | 1,784.46 | 1,784.46 | 1.00 | 25.00 |
| 148 | 34500GRDY/19920V | 25 | 16,033,373.10 | 8,985 | 1,784.46 | 169,147.61 | 94.79 | 2,369.73 |
| 149 | 34500GRDY/19920V | 25 | 448,932.90 | 258 | 1,740.05 | 27,949.34 | 16.06 | 401.56 |
| 150 | 34500GRDY/19920V | 25 | 44,611.50 | 25 | 1,784.46 | 8,922.30 | 5.00 | 125.00 |
| 151 | 12470GRDY/ 7200V | 25 | 41,334.16 | 28 | 1,476.22 | 7,811.42 | 5.29 | 132.29 |
| 152 | 12470GRDY/ 7200V | 25 | 1,551.97 | 1 | 1,551.97 | 1,551.97 | 1.00 | 25.00 |
| 153 | 12470GRDY/ 7200V | 25 | 5,208,295.95 | 3,315 | 1,571.13 | 90,459.44 | 57.58 | 1,439.40 |
| 154 | 12470GRDY/ 7200V | 25 | 158,300.94 | 102 | 1,551.97 | 15,674.13 | 10.10 | 252.49 |
| 155 | 12470GRDY/ 7200V | 25 | 28,723.10 | 10 | 2,872.31 | 9,083.04 | 3.16 | 79.06 |
| 156 | 12470GRDY/ 7200V | 25 | 140,746.74 | 86 | 1,636.59 | 15,177.11 | 9.27 | 231.84 |
| 157 | 12470GRDY/ 7200V | 25 | 1,551.97 | 1 | 1,551.97 | 1,551.97 | 1.00 | 25.00 |
| 158 | 12470GRDY/7200V | 250 | 49,004.85 | 15 | 3,266.99 | 12,653.00 | 3.87 | 968.25 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 368 - Transformers**

| # | Description | Size | Cost | Quantity | Actual Unit Cost ($ per Unit) | Linear Regression Inputs y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|
| 159 | 34500GRDY/19920V | 250 | 7,298.93 | 1 | 7,298.93 | 7,298.93 | 1.00 | 250.00 |
| 160 | 34500GRDY/19920V | 250 | 14,597.86 | 2 | 7,298.93 | 10,322.25 | 1.41 | 353.55 |
| 161 | 34500GRDY/19920V | 250 | 37,233.06 | 6 | 6,205.51 | 15,200.33 | 2.45 | 612.37 |
| 162 | 34500GRDY/19920V | 250 | 1,372,198.84 | 188 | 7,298.93 | 100,077.89 | 13.71 | 3,427.83 |
| 163 | 12470GRDY/ 7200V | 250 | 73,993.35 | 15 | 4,932.89 | 19,105.00 | 3.87 | 968.25 |
| 164 | 12470GRDY/ 7200V | 250 | 3,266.99 | 1 | 3,266.99 | 3,266.99 | 1.00 | 250.00 |
| 165 | 12470GRDY/ 7200V | 250 | 19,897.20 | 5 | 3,979.44 | 8,898.30 | 2.24 | 559.02 |
| 166 | 12470GRDY/ 7200V | 250 | 29,402.91 | 9 | 3,266.99 | 9,800.97 | 3.00 | 750.00 |
| 167 | 12470GRDY/ 7200V | 250 | 9,800.97 | 3 | 3,266.99 | 5,658.59 | 1.73 | 433.01 |
| 168 | 12470GRDY/ 7200V | 250 | 3,266.99 | 1 | 3,266.99 | 3,266.99 | 1.00 | 250.00 |
| 169 | 12470GRDY/ 7200V | 3 | 65,341.50 | 210 | 311.15 | 4,508.99 | 14.49 | 43.47 |
| 170 | 12470GRDY/ 7200V | 3 | 3,111.50 | 10 | 311.15 | 983.94 | 3.16 | 9.49 |
| 171 | 12470GRDY/ 7200V | 333 | 86,029.60 | 8 | 10,753.70 | 30,416.06 | 2.83 | 941.87 |
| 172 | 34500GRDY/19920V | 333 | 9,279.92 | 1 | 9,279.92 | 9,279.92 | 1.00 | 333.00 |
| 173 | 34500GRDY/19920V | 333 | 27,839.76 | 3 | 9,279.92 | 16,073.29 | 1.73 | 576.77 |
| 174 | 7200/12470Y | 333 | 5,599.95 | 3 | 1,866.65 | 3,233.13 | 1.73 | 576.77 |
| 175 | 34500GRDY/19920V | 333 | 13,992.84 | 3 | 4,664.28 | 8,078.77 | 1.73 | 576.77 |
| 176 | 34500GRDY/19920V | 333 | 816,632.96 | 88 | 9,279.92 | 87,053.37 | 9.38 | 3,123.82 |
| 177 | 12470GRDY/ 7200V | 333 | 11,199.90 | 6 | 1,866.65 | 4,572.34 | 2.45 | 815.68 |
| 178 | 12470GRDY/ 7200V | 333 | 4,664.28 | 1 | 4,664.28 | 4,664.28 | 1.00 | 333.00 |
| 179 | 12470GRDY/ 7200V | 333 | 13,992.84 | 3 | 4,664.28 | 8,078.77 | 1.73 | 576.77 |
| 180 | 12470GRDY/ 7200V | 37.5 | 12,332.11 | 7 | 1,761.73 | 4,661.10 | 2.65 | 99.22 |
| 181 | 12470GRDY/ 7200V | 37.50 | 174,195.45 | 99 | 1,759.55 | 17,507.30 | 9.95 | 373.12 |
| 182 | 12470GRDY/ 7200V | 37.5 | 1,581,835.45 | 899 | 1,759.55 | 52,757.17 | 29.98 | 1,124.37 |
| 183 | 12470GRDY/ 7200V | 37.5 | 1,759.55 | 1 | 1,759.55 | 1,759.55 | 1.00 | 37.50 |
| 184 | 12470GRDY/ 7200V | 37.5 | 927,282.85 | 527 | 1,759.55 | 40,393.08 | 22.96 | 860.87 |
| 185 | 12470GRDY/ 7200V | 37.5 | 5,620.86 | 3 | 1,873.62 | 3,245.21 | 1.73 | 64.95 |
| 186 | 12470GRDY/ 7200V | 5 | 204,114.40 | 656 | 311.15 | 7,969.33 | 25.61 | 128.06 |
| 187 | 12470GRDY/ 7200V | 5 | 19,602.45 | 63 | 311.15 | 2,469.68 | 7.94 | 39.69 |
| 188 | 12470GRDY/ 7200V | 50 | 2,012.94 | 1 | 2,012.94 | 2,012.94 | 1.00 | 50.00 |
| 189 | 12470GRDY/ 7200V | 50 | 13,108,265.28 | 6,512 | 2,012.94 | 162,438.15 | 80.70 | 4,034.85 |
| 190 | 12470GRDY/ 7200V | 50 | 790,649.58 | 402 | 1,966.79 | 39,434.02 | 20.05 | 1,002.50 |
| 191 | 12470GRDY/ 7200V | 50 | 4,240.08 | 2 | 2,120.04 | 2,998.19 | 1.41 | 70.71 |
| 192 | 12470GRDY/ 7200V | 50 | 4,240.08 | 2 | 2,120.04 | 2,998.19 | 1.41 | 70.71 |
| 193 | 34500GRDY/19920V | 50 | 361,913.68 | 136 | 2,661.13 | 31,033.84 | 11.66 | 583.10 |
| 194 | 34500GRDY/19920V | 50 | 60,116.48 | 23 | 2,613.76 | 12,535.15 | 4.80 | 239.79 |
| 195 | 34500GRDY/19920V | 50 | 15,966.78 | 6 | 2,661.13 | 6,518.41 | 2.45 | 122.47 |
| 196 | 12470GRDY/7200V | 50 | 16,103.52 | 8 | 2,012.94 | 5,693.45 | 2.83 | 141.42 |
| 197 | 12470GRDY/7200V | 50 | 2,012.94 | 1 | 2,012.94 | 2,012.94 | 1.00 | 50.00 |
| 198 | 34500GRDY/19920V | 50 | 6,562,788.48 | 2,736 | 2,398.68 | 125,467.24 | 52.31 | 2,615.34 |
| 199 | 34500GRDY/19920V | 50 | 505,512.00 | 224 | 2,256.75 | 33,775.94 | 14.97 | 748.33 |
| 200 | 34500GRDY/19920V | 50 | 2,398.68 | 1 | 2,398.68 | 2,398.68 | 1.00 | 50.00 |
| 201 | 34500GRDY/19920V | 50 | 91,149.84 | 38 | 2,398.68 | 14,786.46 | 6.16 | 308.22 |
| 202 | 12470GRDY/7200V | 50 | 20,129.40 | 10 | 2,012.94 | 6,365.48 | 3.16 | 158.11 |
| 203 | 12470GRDY/7200V | 50 | 2,012.94 | 1 | 2,012.94 | 2,012.94 | 1.00 | 50.00 |
| 204 | 12470GRDY/7200V | 50 | 5,988,496.50 | 2,975 | 2,012.94 | 109,792.91 | 54.54 | 2,727.18 |
| 205 | 12470GRDY/7200V | 50 | 62,451.90 | 30 | 2,081.73 | 11,402.10 | 5.48 | 273.86 |
| 206 | 12470GRDY/7200V | 50 | 6,245.19 | 3 | 2,081.73 | 3,605.66 | 1.73 | 86.60 |
| 207 | 12470GRDY/7200V | 50 | 27,535.06 | 14 | 1,966.79 | 7,359.05 | 3.74 | 187.08 |
| 208 | 12470GRDY/7200V | 50 | 129,067.26 | 62 | 2,081.73 | 16,391.56 | 7.87 | 393.70 |
| 209 | 12470GRDY/7200V | 50 | 106,685.82 | 53 | 2,012.94 | 14,654.42 | 7.28 | 364.01 |
| 210 | 12470GRDY/7200V | 500 | 29,017.96 | 2 | 14,508.98 | 20,518.80 | 1.41 | 707.11 |
| 211 | 34500GRDY/19920V | 500 | 30,941.52 | 3 | 10,313.84 | 17,864.09 | 1.73 | 866.03 |
| 212 | 34500GRDY/19920V | 500 | 154,707.60 | 15 | 10,313.84 | 39,945.33 | 3.87 | 1,936.49 |
| 213 | 34500GRDY/19920V | 500 | 20,627.68 | 2 | 10,313.84 | 14,585.97 | 1.41 | 707.11 |
| 214 | 12470GRDY/7200V | 500 | 8,725.46 | 1 | 8,725.46 | 8,725.46 | 1.00 | 500.00 |
| 215 | 34500GRDY/19920V | 500 | 10,313.84 | 1 | 10,313.84 | 10,313.84 | 1.00 | 500.00 |
| 216 | 34500GRDY/19920V | 500 | 3,754,237.76 | 364 | 10,313.84 | 196,775.53 | 19.08 | 9,539.39 |
| 217 | 12470GRDY/7200V | 500 | 17,450.92 | 2 | 8,725.46 | 12,339.66 | 1.41 | 707.11 |
| 218 | 12470GRDY/7200V | 500 | 34,901.84 | 4 | 8,725.46 | 17,450.92 | 2.00 | 1,000.00 |
| 219 | 12470GRDY/7200V | 500 | 43,526.94 | 3 | 14,508.98 | 25,130.29 | 1.73 | 866.03 |
| 220 | 34500GRDY/19920V | 667 | 237,218.32 | 23 | 10,313.84 | 49,463.44 | 4.80 | 3,198.82 |
| 221 | 12470GRDY/7200V | 7.5 | 311.15 | 1 | 311.15 | 311.15 | 1.00 | 7.50 |
| 222 | 12470GRDY/7200V | 7.5 | 622.30 | 2 | 311.15 | 440.03 | 1.41 | 10.61 |
| 223 | 12470GRDY/7200V | 7.5 | 622.30 | 2 | 311.15 | 440.03 | 1.41 | 10.61 |
| 224 | 12470GRDY/7200V | 75 | 209,311.44 | 78 | 2,683.48 | 23,699.85 | 8.83 | 662.38 |
| 225 | 12470GRDY/7200V | 75 | 56,216.80 | 20 | 2,810.84 | 12,570.46 | 4.47 | 335.41 |
| 226 | 34500GRDY/19920V | 75 | 191,365.76 | 64 | 2,990.09 | 23,920.72 | 8.00 | 600.00 |
| 227 | 34500GRDY/19920V | 75 | 11,762.88 | 6 | 1,960.48 | 4,802.18 | 2.45 | 183.71 |
| 228 | 12470GRDY/7200V | 75 | 2,810.84 | 1 | 2,810.84 | 2,810.84 | 1.00 | 75.00 |
| 229 | 12470GRDY/7200V | 75 | 8,432.52 | 3 | 2,810.84 | 4,868.52 | 1.73 | 129.90 |
| 230 | 34500GRDY/19920V | 75 | 206,316.21 | 69 | 2,990.09 | 24,837.55 | 8.31 | 623.00 |
| 231 | 34500GRDY/19920V | 75 | 67,087.00 | 25 | 2,683.48 | 13,417.40 | 5.00 | 375.00 |
| 232 | 12470GRDY/7200V | 75 | 2,683.48 | 1 | 2,683.48 | 2,683.48 | 1.00 | 75.00 |
| 233 | 12470GRDY/7200V | 75 | 2,119,373.36 | 754 | 2,810.84 | 77,183.03 | 27.46 | 2,059.43 |
| 234 | 12470GRDY/7200V | 75 | 81,642.90 | 30 | 2,721.43 | 14,905.89 | 5.48 | 410.79 |
| 235 | 12470GRDY/7200V | 75 | 5,621.68 | 2 | 2,810.84 | 3,975.13 | 1.41 | 106.07 |

**Kentucky Utilities**
**Zero Intercept & Minimum System Analyses**

**Account 368 - Transformers**

| # | Description | Size | | Cost | Quantity | Actual Unit Cost ($ per Unit) | y*n^0.5 | n^0.5 | xn^0.5 |
|---|---|---|---|---|---|---|---|---|---|
| 236 | 34500GRDY/19920V | 833 | | 36,159.31 | 1 | 36,159.31 | 36,159.31 | 1.00 | 833.00 |
| 237 | 34500GRDY/19920V | 833 | | 433,911.72 | 12 | 36,159.31 | 125,259.52 | 3.46 | 2,885.60 |
| 238 | TOTAL | | $ | 175,381,585.52 | 96,166 | | | | |
| 239 | | | | | | | | | |
| 240 | **Zero Intercept Linear Regression Results** | | | | | | **LINEST Array** | | |
| 241 | | | | | | | | | |
| 242 | Size Coefficient ($ per MCM) | | | 25.36489 | | | 25.36489 | 957.65569 | |
| 243 | Zero Intercept ($ per Unit) | | | 957.65569 | | | 0.69829 | 52.69681 | |
| 244 | R-Square | | | 0.9232 | | | 0.92322 | 14,573.24692 | |
| 245 | | | | | | | | | |
| 246 | **Plant Classification** | | | | | | | | |
| 247 | | | | | | | | | |
| 248 | Total Number of Units | | | 96,166 | | | | | |
| 249 | Zero Intercept ($/Unit) | | $ | 957.66 | | | | | |
| 250 | Minimum System ($/Unit) | | $ | 311.15 | | | | | |
| 251 | Use Min System (M) or Zero Intercept (Z)? | | | Z | | | | | |
| 252 | Zero Intercept or Min System Cost ($) | | $ | 92,093,917 | | | | | |
| 253 | Total Cost of Sample | | $ | 175,381,586 | | | | | |
| 254 | Percentage of Total | | | 0.5251 | | | | | |
| 255 | Percentage Classified as Customer-Related | | | 52.51% | | | | | |
| 256 | Percentage Classified as Demand-Related | | | 47.49% | | | | | |

Linear Regression Inputs: columns y*n^0.5, n^0.5, xn^0.5

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_27** | Refer to Kentucky Power's Response to Staff's First Request, Item 33, Confidential Attachment 1. Also refer to Kentucky Power's Motion to Approve the Settlement Agreement, Direct Testimony of Brian West, Exhibit BKW 1-S. |

a. Provide the amount of incentive compensation for each AEPSC employee accrued by Kentucky Power for the test year and what the accrual would have been had only 100 percent of the incentive target been achieved. Provide the amount of incentive compensation tied to financial performance for both scenarios.

b. Provide the adjustment in the Settlement Agreement that reflects the removal of incentive compensation related to financial targets.

**RESPONSE**

a. & b. Please refer to KPCO_R_KPSC_PHDR_27_Attachment1 for the requested information. The "PHDR_27_Summary" tab illustrates that the expense included in the Settlement Agreement revenue requirement is less than the test year expense adjusted to 100 percent of target excluding expense attributed to financial performance. As a part of the compromise reflected in the Settlement Agreement, AG-KIUC Witness Kollen's view of expense attributed to financial performance was used instead of the Company's view.

Witness: Katharine I. Walsh

Witness: Heather M. Whitney

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_28** | Refer to Kentucky Power's response to Staff's Sixth Request, Item 9, Attachment 1. For any included expense provide the date of use, purpose of use, employees that utilized the corporate aircraft, and any other passengers on the aircraft. |

**RESPONSE**

See KPCO_R_KPSC_PHDR_28_Attachment1 for requested information.

Witness: Heather M. Whitney

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_29** | Refer to Case No. 2020-00174 and Case No. 2017-00179. Identify whether storm damage expense recovery in each case was included in capitalization, included in rate base, amortized, or a combination of those accounting mechanisms. Provide the supporting documentation or information for the response. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_29_Attachment1 for the requested information.

Witness: Heather M. Whitney

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_30** | Refer to the Application, Section III, Volume 4, Direct Testimony of Joshua Burkholder, page 10. Provide the LSE OATT expense and revenues for the years 2014 through 2023. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_30_Attachment1 for the requested information.

Witness: Joshua D. Burkholder

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_31** | State whether the test year contains any expenses related to the remarketing of the West Virginia Pollution Control Bond. If so, provide the location and amount of those expenses. |

**RESPONSE**

The test year does not contain any expenses related the remarketing of the West Virginia Pollution Control Bond. Expenses associated with debt issuances or remarketings are included in the calculation of the effective yield, or cost, of debt associated with each debt issuance. Please see Section V, Schedule 3, Workpaper S-3, Page 1 of 3 which contains each long-term debt issuance as well as the calculation of the "Effective Cost Rate" which takes into account the impact of the issuance costs.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_32** | Explain whether the interest rate for the West Virginia Pollution Control Bonds could remain constant as compared to remarketing them every 3 years. |

**RESPONSE**

The West Virginia Pollution Control Bonds can have a range of potential interest rate modes ranging from a floating rate to a fixed maturity of up to 30 years. The West Virginia Pollution Control Bonds were most recently remarketed (repriced) based on a 3-year mandatory put option in which the bonds will need to be remarketed in three years. Generally, the mandatory put options and associated interest rates are available for anywhere from 2 – 10 years. At the end of this time the bonds would be remarketed unless the final maturity is reached. The decision to select a given remarketing period is based on considering current and expected market conditions and investor interest.

Witness: Franz D. Messner

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_33** | Provide where it states in the original contract terms for the West Virginia Pollution Control Bonds that the bonds will be remarketed, where this provision was explained in Kentucky Power's application of Case No. 2016-00345 and where the provision was approved in Case No. 2016-00345. |

**RESPONSE**

The provisions for remarketing terms were provided in the bond indenture executed in 2014. Specifically, Section 2.02, "Interest on the Bonds", which reads, "Interest on the Bonds will be payable as provided in the Bonds and in this Section. The Determination Method may be changed by the Company as described in paragraph (b) of this Section."

KPCO_R_KPSC_PHDR_33_Attachment1 is the order in Case No. 2016-00345 which includes discussion of the West Virginia Pollution Control Bonds.

Witness: Franz D. Messner

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| ELECTRONIC APPLICATION OF KENTUCKY | ) | |
| POWER COMPANY FOR AUTHORITY PURSUANT | ) | CASE NO. |
| TO KRS 278.300 TO ISSUE AND SELL | ) | 2016-00345 |
| PROMISSORY NOTES OF ONE OR MORE SERIES | ) | |
| AND FOR OTHER AUTHORIZATIONS | ) | |

## ORDER

On October 26, 2016, Kentucky Power Company ("Kentucky Power") filed an application seeking Commission approval under KRS 278.300 authorizing it to issue and sell promissory notes of one or more series in the aggregate amount of $550 million and for other relief. Kentucky Power responded to one round of requests for information issued by Commission Staff. There are no intervenors in this proceeding. The case stands submitted to the Commission for a decision based upon the evidentiary record.

## DISCUSSION

Kentucky Power proposes to issue and sell up to $550 million aggregate principal amount of unsecured promissory notes in one or more series in one or more transactions through December 31, 2018. The notes may be issued as (1) Senior Notes, or other unsecured promissory notes, (2) in connection with one or more tax-exempt financing transactions with the West Virginia Economic Development Authority ("WVEDA") and (3) in connection with Kentucky Power's Local Bank Financing Program. Kentucky Power states that the proposed notes will have maturities ranging from a minimum of nine months to a maximum of 60 years and will be sold by competitive bidding, by private offering through negotiation with underwriters or agents, or by direct placement with a commercial bank or institutional investor. Up to $100 million of the proposed $550 million may be financed through Kentucky Power's Local Bank Financing Program, which was approved by the Commission in Case No. 2014-00210.[1] Kentucky Power states that the program provides investment-grade lending opportunities for local banks in its service territory, diversifying and strengthening their loan portfolios, and aiding in economic development of Kentucky Power's service territory.[2] Kentucky Power states that the interest rates may be fixed or variable, depending on what is most advantageous at the time of the issuance and sale of the notes. According to Kentucky Power, any fixed-rate notes will have a yield to maturity not to exceed that of United States Treasury bonds of comparable maturity at the time of pricing, plus 500 basis points, with any initial fluctuating rate of interest not to exceed 8 percent per annum at the time of issuance. Kentucky Power states that agreements to any specific redemption provisions, including redemption premiums, will be made at the time of pricing, and that Kentucky Power may provide the notes with some form of credit enhancement if such is deemed advisable.

According to Kentucky Power's application, one or more notes may be issued to its parent company, American Electric Power Company, Inc. ("AEP"), or to any entity owning either directly or indirectly all of Kentucky Power's common stock. Any such

[1] Case No. 2014-00210, *Application of Kentucky Power Company for Authority Pursuant to KRS 270.300 to Issue and Sell Promissory Notes of One or More Series, and for Other Authorizations* (Ky. PSC Sept. 26, 2014).

[2] Application, paragraph 30.

borrowings will have interest rates and maturity dates that parallel AEP's cost of capital in order to comply with any applicable law or regulation.

Kentucky Power states that it may agree to restrictive covenants in connection with the sale of the notes. Such covenants may, among other things, prohibit it from creating or permitting liens on its property; from creating indebtedness other than what is specified; from failing to maintain a certain financial condition; from entering into mergers, consolidations, and dispositions of assets; and from permitting the occurrence of certain events in connection with pension plan. Kentucky Power may permit the note holders to require Kentucky Power to prepay them after certain specified events, including ownership change.

According to Kentucky Power, present market conditions make it difficult to determine whether it will be more advantageous to sell the proposed notes with a 60-year maturity or with some shorter period. It further states that, in order to obtain the best possible price, interest rate, and terms, it is in the public interest to afford Kentucky Power the flexibility to adjust its financing program as developments in the medium- and long-term debt markets occur. Therefore, Kentucky Power requests that it be permitted to determine at a subsequent date whether there will be more than one series, and, if so, the associated maturity of each series.

Kentucky Power states that any notes may be issued under a new indenture or under the September 1, 1997 indenture with Deutsche Bank Trust Company Americas, Trustee, or with any eligible and qualified successor. Kentucky Power estimates, based on past experience with similar financing, that the total issuance costs for the notes will be approximately $3 million.

Kentucky Power states that it may purchase outstanding securities through tender offer, negotiated or open market purchase or any other form of purchase if such refunding can be accomplished at a lower effective cost than redemption. Kentucky Power indicates that it will determine that any premium paid with respect to a tender offer is prudent compared to savings in interest expense associated with early redemption of any series, and proposes to treat any premium paid as an expense to be amortized over the life of the notes. Kentucky Power maintains that it intends to use deferred tax accounting for the premium expense to properly match amortization of the expense with the related tax effect.

According to Kentucky Power, the actual cost associated with the promissory notes will be determined at the time of sale. Kentucky Power points out that the net effect of the debt issuances will be reflected in the determination of revenue requirements in future rate proceedings in which all factors affecting rates will be taken into account.

Kentucky Power maintains that it will, within 30 days after the issuance of each series of the promissory notes, file a verified statement with the Commission disclosing the date or dates of issuance, the price paid, the interest rate, the purchasers, and all fees and expenses, including underwriting discounts or commissions or other compensation paid by Kentucky Power in connection with the issuance and distribution of the indebtedness.

Kentucky Power proposes to use the proceeds from the $550 million in unsecured promissory notes to fund its capital requirements in connection with ongoing acquisition, construction, and improvement of its facilities, for its general corporate purposes, and to refinance existing notes. Specifically, Kentucky Power seeks authority to issue indebtedness and engage in financings in the amount of $85 million for its general corporate purposes and its capital requirements in connection with ongoing acquisition, construction, and improvement of its facilities[3] and to refinance the $325 million 6.0 percent Senior Note, Series E, due in 2017; the $75 million Variable Rate Local Bank Faculty Program due in 2018; and the $65 million WVEDA, Series 2014A Variable Rate Demand Note Pollution Control Bond due in 2017.

Kentucky Power requests authorization to enter into one or more interest rate hedging agreements from time to time through December 31, 2018, in connection with the issuance of the promissory notes. The proposed interest rate hedging arrangements could include, but are not limited to, treasury lock agreements, forward-starting interest rate swaps, treasury put options, or interest rate collar agreements ("Treasury Hedge Agreement") to protect against future interest rate movements in connection with the issuance of the proposed notes. Each Treasury Hedge Agreement will correspond to one or more issuances of indebtedness proposed in Kentucky Power's application; the aggregate corresponding principal amounts of all Treasury Hedge Agreements will therefore not exceed, on the date or dates of entering such agreements, $550 million.

Kentucky Power proposes to utilize interest rate management techniques and enter into interest rate management agreements ("Interest Rate Management Agreements") through December 31, 2018, to allow it sufficient alternatives and flexibility to reduce its effective interest cost and manage interest cost on financings.

[3] Estimated capital requirements for 2016 through 2018 are $319 million. In response to Staff's First Request for Information, Item 5, the balance of the $319 million will be initially financed using internally supplied funds.

The proposed Interest Rate Management Agreements will consist of "interest rate swaps," "caps," "collars," "floors," "options," or hedging products such as "forwards" or "futures," or similar products, the purpose of which is to manage and minimize interest costs. Kentucky Power states that it expects to enter into these agreements with counterparties that are highly rated financial institutions. The transactions will be for a fixed period and a stated principal amount, and they will be for underlying fixed or variable obligations of Kentucky Power. Kentucky Power will not agree to any covenant more restrictive than those contained in the underlying obligation, unless such Interest Rate Management Agreement either expires by its terms or is unwindable on or prior to the end of the authorization period.[4]

Because market opportunities for these interest rate management alternatives are transitory, Kentucky Power states that it must be able to execute interest rate management transactions when the opportunity arises in order to obtain the most competitive pricing. Kentucky Power seeks approval to enter into any or all of the described transactions within the parameters discussed above prior to the time it reaches agreement with respect to the terms of such transactions.

The use of Interest Rate Management Agreements could cause Kentucky Power's annual long-term interest charges to change. Kentucky Power acknowledges that the Commission's authorization of the use of Interest Rate Management Agreements as described in the application does not relieve it of its responsibility to obtain the best terms available for the product selected. It contends, therefore, that it is

---

[4] Application, paragraph 24.

appropriate and reasonable for the Commission to authorize Kentucky Power to agree to such terms and prices consistent with the stated parameters.

The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds that (1) the proposal to issue and sell, in one or more transactions through December 31, 2018, up to $550 million aggregate principal amount of unsecured promissory notes in one or more new series; and (2) the use of Interest Rate Management Agreements as described in the application are for lawful objects within the corporate purposes of Kentucky Power's utility operations, are necessary and appropriate for and consistent with the proper performance of its service to the public, will not impair its ability to perform that service, are reasonably necessary and appropriate for such purposes, and should therefore be approved. Kentucky Power should further be authorized to execute, deliver, and perform its obligations under all agreements and documents as set out in its application, and to perform the transactions contemplated by such agreements. The Commission further finds that, when Kentucky Power files its statement setting out the details of each debt issuance as required in ordering paragraph 5 below, it should include an explanation of the chosen terms of the indebtedness, including the use of fixed or variable interest rates, and of why the terms were considered most advantageous in both the short and long term at the time of the issuance of the indebtedness.

IT IS THEREFORE ORDERED that:

1. Kentucky Power's proposal to issue and sell, in one or more transactions through December 31, 2018, up to $550 million aggregate principal amount of unsecured promissory notes in one or more new series is approved.

2. Kentucky Power's proposed use of Interest Rate Management Agreements as described in the application is approved.

3. The proceeds from the proposed financing shall be used only for the lawful purposes set out in Kentucky Power's application.

4. The notes authorized herein shall not be issued to an affiliate unless the interest rate is no more than the cost of capital of AEP and the interest rate is equal to or lower than the interest rate on debt available to Kentucky Power from a non-affiliate at the time of issuance.

5. Kentucky Power shall, within 30 days of the issuance, file with the Commission a statement setting forth the date or dates of issuance of the evidences of indebtedness or use of Treasury Hedge or Interest Rate Management Agreements authorized herein, the proceeds of such issuances, the interest rate(s), the maturity date(s), and all fees and expenses involved in the issuances of these evidences of indebtedness or use of such agreements. The statement shall also indicate the amount of financing secured through Kentucky Power's Local Bank Financing Program.

6. Any document filed pursuant to ordering paragraph 5 herein shall reference the number of this case and shall be retained in the utility's general correspondence file.

Nothing contained herein shall be deemed a warranty or finding of value of securities or financing authorized herein on the part of the Commonwealth of Kentucky or any agency thereof.

By the Commission

ENTERED
DEC 21 2016
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Taline R. Mathews
Executive Director

*Kentucky Power Company
101 A Enterprise Drive
P. O. Box 5190
Frankfort, KY  40602

*Kentucky Power Company
Kentucky Power Company
101 A Enterprise Drive
P. O. Box 5190
Frankfort, KY  40602

*Honorable Mark R Overstreet
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KENTUCKY  40602-0634

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_34** | State the party that will be the servicer of ongoing costs for securitization. |

**RESPONSE**

Kentucky Power will be the servicer. Please see response to KPSC 2-66.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_35** | Explain how and when the Big Sandy Decommissioning Rider is updated, including for under- and over-recovery, as well as changes in the Commission approved weighted average cost of capital (WACC). Further, explain whether, without securitization, Kentucky Power would continue updating the Big Sandy Decommissioning Rider as it has. |

**RESPONSE**

The Big Sandy Decommissioning Rider is updated after June accounting close (to provide for July through June actuals) and filed with the Commission by August 15 annually in accordance with the Commission's October 7, 2013 Order in Case No. 2012-00578, its June 22, 2015 Order in Case No. 2014-00396, and its January 13, 2021 Order in Case No. 2020-00174.

The Company incorporates any Commission-required updates in the following updates. For instance, the 7.50% WACC approved in the Commission's January 13, 2021 Order in Case No. 2020-00174 for rates effective January 14, 2021 onward was incorporated into the Company's August 2021 Decommissioning Rider update which included actuals through June 2021. Due to January 2021 having two applicable WACC's, the Company prorated to ensure compliance with the applicable rate case Orders.

Lastly, without securitization, the Company would continue to update the Big Sandy Decommissioning Rider as it has done in the past.

Witness: Lerah M. Kahn

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_36** | Provide a revised net present value analysis for the securitization of the Big Sandy regulatory asset that assumes conventional treatment of the regulatory asset where the WACC increases 0.5 percent per 3.5 years, beginning in 2024. |

**RESPONSE**

The revised net present value analysis for the securitization of the Big Sandy regulatory asset including WACC increases of 0.5 percent every 3.5 years beginning in 2024 is approximately $45.7 million. Attachment KPCO_R_KPSC_PHDR_36_Attachment1 contains the calculation requested. It is based on the as filed Big Sandy regulatory asset, Big Sandy accumulated deferred income tax, and securitization interest rate. Minor adjustments were made to the up front and ongoing costs for those items estimated based on the size of the securitization bond, such as underwriting fees which are assumed to be 40 basis points (0.40%) multiplied by the bond size.

Witness: Franz D. Messner

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_37** | Provide the Issuance and Advice Letters that included expected savings for the last five transactions for which Goldman Sachs has been a party. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_37_Attachments1 through 8 for the requested information.

Witness: Katrina Niehaus

Control Number: 49308

Item Number: 38

Addendum StartPage: 0

FILED
2019 SEP 12 AM 10: 17

**PUC DOCKET NO. 49308**

| | | |
|---|---|---|
| **APPLICATION OF AEP TEXAS INC.** | § | |
| **FOR A FINANCING ORDER TO** | § | **BEFORE THE** |
| **SECURITIZE SYSTEM** | § | **PUBLIC UTILITY COMMISION** |
| **RESTORATION COSTS** | § | **OF TEXAS** |
| | § | |

**September 12, 2019**

**Contact: Jennifer Frederick**
**American Electric Power Service Corporation**
**400 West 15th Street**
**Suite 1520**
**Austin, Texas 78701**
**(512) 481-4573**
**(512) 481-4591 (facsimile)**

**In Compliance with Ordering Paragraph Nos. 6 and 7 of the Financing Order issued on June 17, 2019, AEP Texas Inc. hereby submits its Issuance Advice Letter and Schedule SRC and ~~Rider~~ SRC tariffs.**

**Gilbert Hughes, Director Regulatory Services**

**TABLE OF CONTENTS**



38

# ISSUANCE ADVICE LETTER

**Thursday, September 12, 2019**

**Docket No. 49308**

**THE PUBLIC UTILITY COMMISSION OF TEXAS**

## SUBJECT: ISSUANCE ADVICE LETTER FOR SYSTEM RESTORATION BONDS

Pursuant to the Financing Order adopted in *Application of AEP Texas Inc. for a Financing Order*, Docket No. 49308 (the "Financing Order"), AEP TEXAS INC. ("Applicant") hereby submits, no later than the end of the first business day after the pricing date of this series of System Restoration Bonds, the information referenced below. This Issuance Advice Letter is for the 2019 System Restoration Bonds, tranches A-1 through A-2. Any capitalized terms not defined in this letter have the meanings ascribed to them in the Financing Order.

## PURPOSE

This filing establishes the following:

(a) the total amount of Qualified Costs being securitized;
(b) confirmation of compliance with issuance standards;
(c) the actual terms and structure of the System Restoration Bonds being issued;
(d) the initial System Restoration Charges for retail users; and
(e) the identification of the Special Purpose Entity ("SPE").

## QUALIFIED COSTS BEING SECURITIZED

The total amount of Qualified Costs being securitized (the "Securitized Qualified Costs") is presented in Attachment 1.

## COMPLIANCE WITH ISSUANCE STANDARDS

The Financing Order requires Applicant to confirm, using the methodology approved therein, that the actual terms of the System Restoration Bonds result in compliance with the standards set forth in the Financing Order. These standards are:

1. The securitization of Qualified Costs will provide tangible and quantifiable benefits to ratepayers, greater than would be achieved absent the issuance of the System Restoration Bonds (See Attachment 2, Schedule D);

2. The amount securitized will not exceed the present value of the conventional revenue requirement over the life of the System Restoration Bonds associated with the Securitized Qualified Costs when the present value calculation is made using a discount rate equal to the proposed interest rate on the System Restoration Bonds (See Attachment 2, Schedule D);

3. The total amount of revenues to be collected under the Financing Order is less than the revenue requirement that would be recovered using conventional financing methods (See Attachment 2, Schedule C and D);

4. The System Restoration Bonds will be issued in one or more series comprised of one or more tranches having target final payments of 10 years and legal final maturities not exceeding 12 years from the date of issuance of such series (See Attachment 2, Schedule A);

5. The System Restoration Bonds may be issued with an original issue discount, additional credit enhancements, or arrangements to enhance marketability provided that the Applicant certifies that the original issue discount is reasonably expected to provide benefits greater than its cost; and

6. The structuring and pricing of the System Restoration Bonds is certified by the Applicant to result in the lowest System Restoration Charges consistent with market conditions and the terms (including the amortization structure ordered by the Commission, if any) set out in the Financing Order (See Attachment 4).

## ACTUAL TERMS OF ISSUANCE

System Restoration Bond Series: Senior Secured Restoration Bonds
System Restoration Bond Issuer: **AEP Texas Restoration Funding LLC**
Trustee: U.S. Bank National Association
Closing Date: September 18, 2019
Bond Ratings: S&P AAA(sf), Moody's Aaa(sf)
Amount Issued: $235,282,000
System Restoration Bond Up-Front Qualified Costs: See Attachment 1, Schedule B.
System Restoration Bond Ongoing Qualified Costs: See Attachment 2, Schedule B.

| Tranche | Coupon Rate | Tranche Size | Expected Weighted Average Life | Expected Final Payment | Legal Final Maturity |
|---|---|---|---|---|---|
| A-1 | 2.0558% | $117,641,000 | 3.05 yrs | 2/1/2025 | 2/1/2027 |
| A-2 | 2.2939% | $117,641,000 | 7.87 yrs | 8/1/2029 | 8/1/2031 |

| | |
|---|---|
| Effective Annual Weighted Average Interest Rate of the System Restoration Bonds: | **2.2250 %** |
| Life of Series: | **10 years** |
| Weighted Average Life of Series: | **5.46 years** |
| Call provisions (including premium, if any): | None |
| Target Amortization Schedule: | Attachment 2, Schedule A |
| Target Final Payment Dates: | Attachment 2, Schedule A |
| Legal Final Maturity Dates: | Attachment 2, Schedule A |
| Payments to Investors: | Semiannually Beginning February 1, 2020 |
| Initial annual Servicing Fee as a percent of original System Restoration Bond principal balance: | 0.10% |

**INITIAL SYSTEM RESTORATION CHARGE**

Table I below shows the current assumptions for each of the variables used in the calculation of the initial System Restoration Charges.

| **TABLE I** | |
|---|---|
| **Input Values For Initial System Restoration Charges** | |
| Applicable period: from 9/18/2019 to 8/31/2020 | |
| Forecasted retail kWh/kW sales for the applicable period: | **9,629,720,961** |
| System Restoration Bond debt service for the applicable period | **$18,815,038** |
| Percent of billed amounts expected to be charged-off: | **1.116%** |
| Forecasted % of Billing Paid in the Applicable Period: | **86.891%** |
| Forecasted retail kWh/kW sales billed and collected for the applicable period. | **8,367,333,519** |
| Forecasted annual ongoing transaction expenses (Excluding System Restoration Bond principal and interest): | **$464,282** |
| Initial System Restoration Bond outstanding balance: | **$235,282,000** |
| Target System Restoration Bond outstanding balance as of: 8/31/2020: | **$220,881,917** |
| Total Periodic Billing Requirement for applicable period: | **$24,907,814** |

Allocation of the PBR among customer classes: See Attachment 3.

Based on the foregoing, the initial System Restoration Charges calculated for retail users are as follows:

| TABLE II | |
|---|---|
| | |
| Rate Class | Initial System Restoration Charge |
| | |
| Residential | **$0.001455/kWh** |
| Secondary Service Less Than or Equal to 10 kW | **$0.001798/kWh** |
| Secondary Service Greater Than 10 kW | **$0.297415/Distribution Billing kW** |
| Primary Service | **$0.238983/Distribution Billing kW** |
| Lighting Service | **$0.008215/kWh** |

## IDENTIFICATION OF SPE

The owner of the Transition Property will be: **AEP Texas Restoration Funding LLC**

## EFFECTIVE DATE

In accordance with the Financing Order, the System Restoration Charge shall be automatically effective upon the Applicant's receipt of payment in the amount of $231,184,014[1] from **AEP Texas Restoration Funding LLC**, following Applicant's execution and delivery to **AEP Texas Restoration Funding LLC** of the Bill of Sale transferring Applicant's rights and interests under the Financing Order and other rights and interests that will become Transition Property upon transfer to **AEP Texas Restoration Funding LLC** as described in the Financing Order.

[1] The total securitized qualified costs less the sum of up-front qualified costs and original issue discount of $400.

## NOTICE

Copies of this filing are being furnished to the parties on the attached service list. Notice to the public is hereby given by filing and keeping this filing open for public inspection at Applicant's corporate headquarters.

## AUTHORIZED OFFICER

The undersigned is an officer of Applicant and authorized to deliver this Issuance Advice Letter on behalf of Applicant.

Respectfully submitted,

AEP TEXAS INC.

By:
Name: Renee V. Hawkins
Title: Assistant Treasurer

**ATTACHMENT 1**
**SCHEDULE A**
**CALCULATION OF SECURITIZED QUALIFIED COSTS**

| | |
|---|---|
| Securitizable Balance to be securitized: | $231.184.414 |
| Up-front Qualified Costs | $4.097,586 |
| **TOTAL SECURITIZED QUALIFIED COSTS** | **$235,282,000** |

**ATTACHMENT 1**
**SCHEDULE B**
**ESTIMATED UP-FRONT QUALIFIED COSTS**

| **CAPPED UP-FRONT QUALIFIED COSTS** | |
|---|---|
| | |
| Legal Fees (Company, Issuer, and Underwriter) | $ 2,341,043 |
| Accountant's Fees | $ 145,000 |
| Trustee's/Trustee Counsel's Fees and Expenses | $ 41,000 |
| Servicer's Set-up Costs | $ 155,000 |
| Printing/Edgarizing | $ 45,000 |
| Company Advisor's Fee | $ 150,000 |
| SPE Setup Costs | $ - |
| Securitization Proceeding Expenses | $ - |
| Miscellaneous Administrative Costs | $ 4,000 |
| Underwriters' Fees | $ 941,128 |
| Settlement Cap | $ (173,310) |
| Subtotal Capped Up-Front Qualified Costs | **$ 3,648,861** |
| | |
| Commission's Financial Advisor Fees | $ 50,000 |
| Legal Fees for Counsel to the Commission's Advisor | |
| Original Issue Discount | $ 400 |
| Cost of Other Credit Enhancements | $ - |
| Rounding/Contingency | $ (399) |
| Rating Agency Fees | $ 370,000 |
| SEC Registration Fee | $ 28,724 |
| | |
| **TOTAL UP-FRONT QUALIFIED COSTS SECURITIZED** | **$ 4,097,586** |

**Note: Certain costs are subject to an aggregate cap set forth in the Financing Order. Differences that result from the Estimated Up-front Qualified Costs securitized being more than the actual up-front costs incurred will be resolved through the true-up process described in the Financing Order. Differences that result from the Estimated Up-front Qualified Costs securitized being less than the actual up-front costs incurred may be resolved in a future proceeding as described in the Financing Order, provided that the total amount of capped costs may not be recovered in excess of the aggregate cap.**

**ATTACHMENT 2**
**SCHEDULE A**
**SYSTEM RESTORATION BOND REVENUE REQUIREMENT INFORMATION**

**TRANCHE A-1**

| Payment Date | Principal Balance | Interest | Principal | Total Payment |
|---|---|---|---|---|
| | 117,641,000 | | | |
| 2/1/2020 | 114,331,459 | 893,488 | 3,309,541 | 4,203,029 |
| 8/1/2020 | 103,240,917 | 1,175,213 | 11,090,541 | 12,265,755 |
| 2/1/2021 | 92,036,376 | 1,061,213 | 11,204,541 | 12,265,755 |
| 8/1/2021 | 80,716,663 | 946,042 | 11,319,713 | 12,265,755 |
| 2/1/2022 | 69,280,595 | 829,687 | 11,436,068 | 12,265,755 |
| 8/1/2022 | 57,726,976 | 712,135 | 11,553,619 | 12,265,755 |
| 2/1/2023 | 46,054,597 | 593,376 | 11,672,379 | 12,265,755 |
| 8/1/2023 | 34,262,238 | 473,395 | 11,792,359 | 12,265,755 |
| 2/1/2024 | 22,348,665 | 352,182 | 11,913,573 | 12,265,755 |
| 8 1 2024 | 10,312,632 | 229,722 | 12,036,033 | 12,265,755 |
| 2 1/2025 | 0 | 106,004 | 10,312,632 | 10,418,636 |

**TRANCHE A-2**

| Payment Date | Principal Balance | Interest | Principal | Total Payment |
|---|---|---|---|---|
| | 117,641,000 | | | |
| 2 1/2020 | 117,641,000 | 996,971 | 0 | 996,971 |
| 8/1/2020 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 2 1/2021 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 8 1 2021 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 2 1 2022 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 8 1 2022 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 2/1/2023 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 8/1/2023 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 2/1/2024 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 8/1/2024 | 117,641,000 | 1,349,283 | 0 | 1,349,283 |
| 2/1/2025 | 115,793,881 | 1,349,283 | 1,847,119 | 3,196,402 |
| 8/1/2025 | 103,506,941 | 1,328,098 | 12,286,940 | 13,615,038 |
| 2/1/2026 | 91,079,076 | 1,187,173 | 12,427,865 | 13,615,038 |
| 8/1/2026 | 78,508,669 | 1,044,631 | 12,570,407 | 13,615,038 |
| 2/1/2027 | 65,794,086 | 900,455 | 12,714,583 | 13,615,038 |
| 8/1/2027 | 52,933,674 | 754,625 | 12,860,413 | 13,615,038 |
| 2/1/2028 | 39,925,758 | 607,123 | 13,007,915 | 13,615,038 |
| 8/1/2028 | 26,768,649 | 457,928 | 13,157,110 | 13,615,038 |
| 2/1/2029 | 13,460,634 | 307,023 | 13,308,015 | 13,615,038 |
| 8/1/2029 | 0 | 154,387 | 13,460,634 | 13,615,021 |

**Legal Final Maturity:**

Tranche A-1 February 1, 2027
Tranche A-2 August 1, 2031

**ATTACHMENT 2**
**SCHEDULE B**
**ONGOING QUALIFIED COSTS**

| | ANNUAL AMOUNT |
|---|---|
| Servicing Fee (AEP Texas as Servicer) (0.10% of initial System Restoration Bond principal amount) | **$235,282** |
| Administration Fee | **$100,000** |
| Accountant's Fee | **$38,000** |
| Legal Fees/Expenses for Company's/Issuer's Counsel | **$10,000** |
| Trustee's/Trustee's Counsel Fees and Expenses | **$6,000** |
| Independent Manager's Fees | **$2,500** |
| Rating Agency Fees | **$52,500** |
| Printing/Edgarizing Fees | **$10,000** |
| Miscellaneous | **$10,000** |
| | |
| **TOTAL ONGOING QUALIFIED COSTS (with AEP Texas as Servicer)** | **$464,282** |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of principal amount) | **$1,411,692** |
| **TOTAL ONGOING QUALIFIED COSTS (Third Party as Servicer** | **$1,640,692** |

**Note: Certain of the Ongoing Qualified Costs are subject to caps set forth in the Financing Order. The amounts shown for each category of operating expense on this attachment are the expected expenses for the first year of the System Restoration Bonds. System Restoration Charges will be adjusted at least annually to reflect any changes in Ongoing Qualified Costs through the true-up process described in the Financing Order.**

**ATTACHMENT 2**
**SCHEDULE C**
**CALCULATION OF SYSTEM RESTORATION CHARGES**

| Year | System Restoration Bond Payments | Ongoing Costs | Total Nominal System Restoration Charge Requirement | Present Value of System Restoration Charges |
|---|---|---|---|---|
| 1 | 18,815,038 | 403,667 | 19,218,705 | 18,911,123 |
| 2 | 27,230,076 | 464,282 | 27,694,358 | 26,719,946 |
| 3 | 27,230,076 | 464,282 | 27,694,358 | 26,135,203 |
| 4 | 27,230,076 | 464,282 | 27,694,358 | 25,563,257 |
| 5 | 27,230,076 | 464,282 | 27,694,358 | 25,003,827 |
| 6 | 27,230,076 | 464,282 | 27,694,358 | 24,456,640 |
| 7 | 27,230,076 | 464,282 | 27,694,358 | 23,921,427 |
| 8 | 27,230,076 | 464,282 | 27,694,358 | 23,397,928 |
| 9 | 27,230,076 | 464,282 | 27,694,358 | 22,885,884 |
| 10 | 27,230,059 | 464,282 | 27,694,341 | 22,385,033 |
| **Total** | **263,885,705** | **4,582,205** | **268,467,910** | **239,380,268** |

**ATTACHMENT 2**
**SCHEDULE D**
**COMPLIANCE WITH SUBCHAPTER G OF THE UTILITIES CODE**

Tangible & Quantifiable Benefits and Revenue Requirements Tests:[2]

| | Conventional Financing[3] | Securitization Financing[4] | Savings/(Cost) of Securitization Financing |
|---|---|---|---|
| Nominal | $353.3 million | $268.5 million | $84.8 million |
| Present Value | $313.2 million | $239.4 million | $73.8 million |

[2] Calculated in accordance with the methodology cited in the Financing Order.
[3] Conventional Financing of storm related costs includes carrying cost of 7.4992% and a term of 10 years as provided in the Financing Order.
[4] From Attachment 2, Schedule C. The discount rate used is the weighted average annual interest rate of the system restoration bonds (2.2250%).

**ATTACHMENT 3**
**INITIAL ALLOCATION OF COSTS TO SRC CLASSES**

| SRC Class | PBRAF | Periodic Billing Requirement | Billing Requirement per SRC Class | Forecasted Billing Determinants | SRC Charge |
|---|---|---|---|---|---|
| Residential | 52.5194% | $24,907,814 | $13,081,435 | 8,988,156,882 | $0.001455/kWh |
| Secondary Service Less Than or Equal to 10 kW | 2.9287% | $24,907,814 | $729,475 | 405,788,287 | $0.001798/kWh |
| Secondary Service Greater Than 10 kW | 31.8567% | $24,907,814 | $7,934,808 | 26,679,250 | $0.297415/Distributior Billing kW |
| Primary Service | 6.0053% | $24,907,814 | $1,495,789 | 6,258,984 | $0.238983/Distributior Billing kW |
| Lighting Service | 6.6899% | $24,907,814 | $1,666,308 | 202,837,557 | $0.008215/kWh |
| Total | 100.0000% | | $24,907,814 | | |

**ATTACHMENT 4**
**FORM OF APPLICANT'S CERTIFICATION**

AEP TEXAS
An AEP Company

Date: September 12, 2019

Public Utility Commission of Texas
1701 N. Congress Ave.
P.O. Box 13362
Austin, TX 78711-3326

Re: *Application of AEP Texas Inc. for a Financing Order*, Docket No. 49308

AEP TEXAS INC. (the "Applicant") submits this Certification pursuant to Ordering Paragraph No. 6 of the Financing Order in *Application of AEP Texas Inc. for a Financing Order*, Docket No. 49308 (the "Financing Order"). All capitalized terms not defined in this letter have the meanings ascribed to them in the Financing Order.

In its issuance advice letter dated September 12, 2019, the Applicant has set forth the following particulars of the System Restoration Bonds:

Name of System Restoration Bonds: **Senior Secured Restoration Bonds**

SPE: **AEP Texas Restoration Funding LLC**

Closing Date: September 18, 2019

Amount Issued: $235,282,000

Expected Amortization Schedule: See Attachment 2, Schedule A to the Issuance Advice Letter

Distributions to Investors: Semi-annually

Weighted Average Coupon Rate: 2.2274%

Weighted Average Yield: 2.2250%

The following actions were taken in connection with the design, marketing, structuring and pricing of the bonds:

- Included credit enhancement in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount.

- Registered the System Restoration Bonds with the Securities and Exchange Commission to facilitate greater liquidity.

- Achieved preliminary Aaa(sf)/AAA(sf) ratings from two of the three major rating agencies with final Aaa(sf)/AAA(sf) ratings a condition of closing.

- Worked with the Commission's designated representative(s) to select underwriters that have relevant experience and execution capability.

- The marketing presentations were developed to emphasize the unique credit quality and security related to these bonds, and provide comparative analysis to other competing securities.

    - Provided the preliminary prospectus by e-mail to prospective investors.

    - Allowed sufficient time for investors to review the preliminary prospectus and to ask questions regarding the transaction.

    - Ensured that the offering materials and investor presentation materials describe the legislative, political and regulatory framework and the bond structure with a focus on corporate/agency/other crossover buyers specifically targeted to achieve the transaction objectives, and held telephone one-on-one conference calls with potential investors to discuss and answer questions.

- Arranged for the issuance of rating agency pre-sale reports during the marketing period.

- During the period that the System Restoration Bonds were marketed, held daily market update discussions with the underwriting team to develop recommendations for pricing.

- Had multiple conversations with all of the members of the underwriting team before and during the marketing phase in which we stressed the requirements of the Financing Order.

- Developed and implemented a marketing plan designed to give each of the underwriters incentive to aggressively market the System Restoration Bonds to their customers and to reach out to a broad base of potential investors, including investors who have not previously purchased this type of security.

    - Provided potential investors with access to an internet roadshow for viewing on repeated occasions at investors' convenience.
    - Adapted the System Restoration Bond offering to market conditions and investor demand at the time of pricing. Variables impacting the final structure of the transaction were

evaluated including the length of average lives and maturity of the System Restoration Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order. After evaluation, incorporated the use of original issue discount to investors consistent with the expectation that it would provide greater benefit than its costs.

- Worked with the Commission's designated representative to develop bond allocations, underwriter compensation and preliminary price guidance designed to achieve lowest interest rates.

- Worked with Commission and underwriters (and each of our respective counsels) to finalize documentation in accordance with established standards for transactions of this sort and the terms of the financing order.

Based upon information reasonably available to the officers, agents, and employees of the Applicant, the Applicant hereby certifies that the structuring and pricing of the System Restoration Bonds, as described in the issuance advice letter, will result in the lowest system restoration bond charges consistent with market conditions and the terms of the Financing Order (including the amortization structure, if any, ordered by the Commission), all within the meaning of Sections 39.301 and 36.401 of PURA.

AEP TEXAS INC.

By:
Name: Renee V. Hawkins
Title: Assistant Treasurer

AEP TEXAS - CENTRAL DIVISION
TARIFF FOR ELECTRIC DELIVERY SERVICE
Applicable: Certified Service Area previously served by AEP Texas Central Company
Chapter: 6 Section: 6.1.1
Section Title: Delivery System Charges
Revision: Original Effective Date: Bills Rendered on or after September 18, 2019

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

**DEFINITIONS**

For the purposes of this schedule the following terms shall have the following meanings:

**Company** – AEP Texas and its successors and assigns that provide transmission or distribution service directly to customers taking service at facilities, premises, or loads located within the Service Area.

**Financing Order** – the Financing Order issued by the Public Utility Commission of Texas (Commission) in Docket No. 49308 under Subchapter I of Chapter 36 and Subchapter G of Chapter 39 of the Texas Public Utility Regulatory Act (PURA) providing for the issuance by the Special Purpose Entity (SPE) of system restoration bonds to securitize the amount of qualified costs (Qualified Costs) determined by the Commission in such order.

**Non-Eligible Self-Generation (NESG)** – Electric generation capacity greater than 10 megawatts capable of being lawfully delivered to a site without use of utility distribution or transmission facilities and which was not, on or before the date the Financing Order is issued, either (A) a fully operational facility, or (B) a project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Commission on Environmental Quality, and which materially reduces or reduced customer loads on the Company's transmission and distribution system

**Retail Electric Provider (REP)** – the entity which serves the customer's energy needs, and will remit to the Servicer the System Restoration Charges billed in accordance with this schedule.

**Service Area** – the Company's certificated Central Division service area, the service area previously served by AEP Texas Central Company, as it existed on the date of approval of the Financing Order in Docket No. 49308.

**Servicer** – on the effective date of this tariff, the Company shall act as Servicer. However, the SPE may select another party to function as Servicer or the Company may resign as Servicer in accordance with terms of the Servicing Agreement and Financing Order issued in Docket No. 49308. A Servicer selected under these conditions shall assume the obligations of the Company as Servicer under this schedule. As used in this schedule, the term Servicer includes any successor Servicer.

**Special Purpose Entity (SPE)** – the owner of Transition Property, on behalf of whom the SRCs are collected.

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

**System Restoration Charge (SRC)** – a non-bypassable charge computed on the basis of individual end-use retail customer consumption, except for SRCs applicable to NESG for which charges are based on the output of the on-site generation utilized to meet the internal electrical requirements of the customer.

(a) For customers whose facilities, premises, and loads are subject to SRCs billed and collected pursuant to the System Restoration Charge Rates (SRC Rates) under this schedule, the SRC Rates shall constitute a separate charge.

(b) The assessment of SRCs will be separately identified on the bills sent to REPs.

**APPLICABILITY**

This schedule, along with Rider SRC, sets out the rates, terms and conditions under which SRCs shall be billed and collected by the Company, any successor Servicer(s), and any REPs on behalf of the owner of Transition Property pursuant to the terms of the Financing Order. This schedule is applicable to energy consumption and demands of retail customers taking transmission and distribution service from the Company and to facilities, premises and loads of such retail customers.

This schedule also applies to:

1. Retail customers taking service at facilities, premises, or loads located within the Service Area who are not presently receiving transmission and distribution service from the Company, but whose present facilities, premises, or loads received transmission and distribution service from the Company at any time on or after the date of approval of the Financing Order in Docket No. 49308 when a request to change service to another utility was not pending as of that date.

2. Retail customers located within the Service Area and prior retail customers of the Company who are served by new NESG.

Individual end-use customers are responsible for paying SRCs billed to them in accordance with the terms of this schedule. Payment is to be made to the entity that bills the customer in accordance with the terms of the Servicing Agreement and the Financing Order, which entity may be the

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

Company, a successor Servicer, a REP, an entity designated to collect SRCs in place of the REP, or other entity which, under the terms of the Financing Order or PURA, may be obligated to pay or collect the SRCs. The REP, an entity designated to collect SRCs in place of the REP, or another entity which, under the terms of the Financing Order or PURA, is obligated to pay or collect the SRCs will pay the SRCs to the Servicer. The Servicer will remit collections to the SPE in accordance with the terms of the Servicing Agreement.

**TERM**

This schedule shall remain in effect until SRCs have been collected and remitted to the SPE which are sufficient in amount to satisfy all obligations of the SPE in regard to paying principal and interest on the System Restoration Bonds together with all other qualified costs as provided in PURA section 36.403(d). However, in no event shall the SRCs provided for in this schedule be collected for service rendered after 15 years from issuance of the System Restoration Bonds. SRCs for service rendered during the 15-year period following issuance of the System Restoration Bonds pursuant to the Financing Order, but not collected during that 15-year period, may be collected after the 15-year period. This schedule is irrevocable and non-bypassable for the full term during which it applies.

**RATE CLASSES**

For the purposes of billing SRCs, each retail end-use customer shall be designated as a customer in one of the following five customer classes. A new customer shall be assigned to the appropriate customer class based on anticipated usage characteristics.

Residential
Secondary Service Less Than or Equal to 10 kW
Secondary Service Greater Than 10 kW
Primary Service
Lighting Service

**PERIODIC BILLING REQUIREMENT ALLOCATION FACTORS**

The following Periodic Billing Requirement Allocation Factors (PBRAF) to be used in the calculation of the SRC Rates are calculated using the methods approved by the Commission in the Financing Order. The PBRAFs shall be the percentage of cost responsibility for each System Restoration Charge customer class.

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

| System Restoration Charge Class | PBRAF |
|---|---|
| Residential | 52.5194% |
| Secondary Service Less Than or Equal to 10 kW | 2.9287% |
| Secondary Service Greater Than 10 kW | 31.8567% |
| Primary Service | 6.0053% |
| Lighting Service | 6.6899% |

**DETERMINATION OF SYSTEM RESTORATION CHARGE (SRC) RATES**

SRC Rates will be adjusted no less frequently than annually in order to ensure that the expected collection of SRCs is adequate to pay when due, pursuant to the expected amortization schedule, principal and interest on the System Restoration Bonds and pay on a timely basis other Qualified Costs. The SRC Rates shall be computed by multiplying the PBRAFs times the Periodic Billing Requirement (PBR) for the projected period in which the adjusted SRC Rates are expected to be in effect (SRC Period), and dividing such amount by the billing units of the SRC customer class, as shown in the following formula:

$$SRC_c = [(PBR * PBRAF_c) + P_c] / FBU_c$$

where,

$SRC_c$ = System Restoration Charge Rate applicable to a SRC rate class during the SRC Period;

PBR = Periodic Billing Requirement for the SRC Period;

$PBRAF_c$ = The Periodic Billing Requirement Allocation Factor for such class in effect at such time;

$P_c$ = Prior period over-/under-recovery for such class;

$FBU_c$ = Forecasted Billing Units (i.e., class-specific energy or demand billing units) currently forecast for a class for the SRC period.

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

**TRUE-UP ADJUSTMENT PROCEDURE**

Not less than 15 days prior to the first billing cycle for the Company's September billing month, and no less frequently than annually, the Servicer shall file a revised Rider SRC setting forth the upcoming SRC period's SRC Rates, complete with all supporting materials. The adjusted SRC Rates will become effective on the first billing cycle of the Company's September billing month. The Commission will have 15 days after the date of the true-up filing in which to confirm the accuracy of the of the Servicer's adjustment. Any necessary corrections to the adjusted SRC Rates, due to mathematical errors in the calculation of such rates or otherwise, will be made in a future true-up adjustment filing.

In addition, optional interim true-up adjustments may be made more frequently by the Servicer at any time during the term of the system restoration bonds to correct any undercollection or overcollection, as provided for in the Financing Order, in order to assure timely payment of the System Restoration Bonds based on rating agency and bondholder considerations. Mandatory interim true-up adjustments shall be made semi-annually (or quarterly after the final scheduled payment date of the last tranche of the System Restoration Bonds) if the Servicer forecasts that system restoration charge collections will be insufficient to make all scheduled payments of principal, interest and other amounts in respect of the System Restoration Bonds on a timely basis during the current or next succeeding payment period and/or or to replenish any draws upon the capital subaccount. The interim true-up adjustment will be filed no later than 15 days prior to the following month's first billing cycle for implementation. Filing with and review by the Commission will be accomplished for the interim true-up adjustment in the manner as for the annual true-up adjustment set forth above. In no event will a mandatory interim true–up adjustment occur more frequently than every six months provided, however, that mandatory interim true-up adjustments after the final scheduled payment date of the last tranche of the System Restoration Bonds shall occur quarterly.

In the event that the forecasted billing units for one or more of the System Restoration Charge customer classes for an upcoming period decreases by more than 10% of the threshold billing units set forth in the Financing Order, the Servicer shall make a true-up filing at least 90 days before the effective date of the next annual true-up adjustment. The true-up shall be conducted in the following manner. The Servicer shall:

(a) allocate the upcoming period's Periodic Billing Requirement based on the PBRAFs approved in the Financing Order;

### 6.1.1.6.3 Schedule SRC - System Restoration Charge

(b) calculate undercollections or overcollections from the preceding period in each class by subtracting the previous period's system restoration charge revenues collected from each class from the Periodic Billing Requirement determined for that class for the same period;

(c) sum the amounts allocated to each customer class in steps (a) and (b) above to determine an adjusted Periodic Billing Requirement for each customer class;

(d) divide the Periodic Billing Requirement for each customer class by the maximum of the forecasted billing units or the threshold billing units for that class, to determine the threshold rate;

(e) multiply the threshold rate by the forecasted billing units for each class to determine the expected collections under the threshold rate;

(f) allocate the difference in the adjusted Periodic Billing Requirement and the expected collections calculated in step (e) among the system restoration charge customer classes using the PBRAFs approved in this Financing Order;

(g) add the amount allocated to each class in step (f) above to the expected collection amount by class calculated in step (e) above to determine the final Periodic Billing Requirement for each class; and

(h) divide the final Periodic Billing Requirement for each class by the forecasted billing units to determine the system restoration charge rate by class for the upcoming period. The final Periodic Billing Requirement class percentage of the total Periodic Billing Requirement equals the adjusted PBRAFs.

**BILLING AND COLLECTION TERMS AND CONDITIONS**

The billing and collection of SRCs may differ as set forth in this schedule. The terms and conditions for each party are set forth below:

AEP TEXAS - CENTRAL DIVISION
TARIFF FOR ELECTRIC DELIVERY SERVICE
Applicable: Certified Service Area previously served by AEP Texas Central Company
Chapter: 6 Section: 6.1.1
Section Title: Delivery System Charges
Revision: Original Effective Date: Bills Rendered on or after September 18, 2019

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

A. Billings by Servicer to other electric utilities, municipally owned utilities, and cooperatives:

1. Applicable to former retail customers of the Company in multiply certificated service areas who requested to switch from the Company to a different service provider on or after approval of the Financing Order, and are now taking service from other electric utilities, municipally owned utilities, or cooperatives or through REPs served from other electric utilities, municipally owned utilities, or cooperatives.

2. Charges subject to this tariff must be paid in full by the other electric utility, municipally owned utility, or cooperative to the Servicer 35 days after billing by the Servicer regardless of whether the electric utility, municipally owned utility, or cooperative collects such charges from the end-use retail customer or from the REP, if applicable.

B. Billings by Servicer to NESG:

1. Applicable to end-use consumption served by on-site non-eligible self generation. The SRCs applicable to NESG are in addition to the applicable System Restoration Charges under A above or C below.

2. Payment terms pursuant to the requirements of PURA, applicable Commission rules, and the Commission's Financing Order in Docket No. 49308.

3. Rate class determined by summing loads on the transmission and distribution system with loads served by non-eligible generation.

4. Servicer has the right to terminate for non-payment pursuant to the Commission's rules.

C. Billings by the REP or its Replacement to End-Use Customers:

1. Applicable to consumption of all retail end-use customers served by the REP for which SRCs apply, including applicable former customers and NESG, under the following conditions:

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

2. REPs shall provide the Servicer with full and timely information necessary to provide proper reporting and for billing and true-up adjustments.

3. Each REP must (1) have a long-term, unsecured credit rating of not less than "BBB-" and "Baa3" (or the equivalent) from Standard & Poor's and Moody's Investors Service, respectively, or (2) provide (A) a deposit of two months' maximum expected System Restoration Charge collections in the form of cash, (B) an affiliate guarantee, surety bond, or letter of credit providing for payment of such amount of System Restoration Charge collections in the event that the REP defaults in its payment obligations, or (C) a combination of any of the foregoing. A REP that does not have or maintain the requisite long-term, unsecured credit rating may select which alternate form of deposit, credit support, or combination thereof it will utilize, in its sole discretion. The Indenture Trustee shall be the beneficiary of any affiliate guarantee, surety bond or letter of credit. The provider of any affiliate guarantee, surety bond, or letter of credit must have and maintain a long-term, unsecured credit ratings of not less than "BBB-" and "Baa3" (or the equivalent) from Standard & Poor's and Moody's Investors Service, respectively.

4. If the long-term, unsecured credit rating from either Standard & Poor's or Moody's Investors Service of a REP that did not previously provide the alternate form of deposit, credit support, or combination thereof or of any provider of an affiliate guarantee, surety bond, or letter of credit is suspended, withdrawn, or downgraded below "BBB-" or "Baa3" (or the equivalent), the REP must provide the alternate form of deposit, credit support, or combination thereof, or new forms thereof, in each case from providers with the requisite ratings, within 10 business days following such suspension, withdrawal, or downgrade. A REP failing to make such provision must comply with the provisions set forth in Paragraph 3 of the next section, Billings by the Servicer to the REP or its Replacement (when applicable).

5. The computation of the size of a required deposit shall be agreed upon by the Servicer and the REP, and reviewed no more frequently than quarterly to ensure that the deposit accurately reflects two months' maximum collections. Within 10 business days following such review, (1) the REP shall remit to the Indenture Trustee the amount of any shortfall in such required deposit or (2) the Servicer shall instruct the Indenture Trustee to remit to the REP any amount in excess of such required deposit. A REP failing to so remit any such shortfall must comply with

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

the provisions set forth in Paragraph 3 of the next section, Billings by the Servicer to the REP or its Replacement (when applicable). REP cash deposits shall be held by the Indenture Trustee, maintained in a segregated account, and invested in short-term high quality investments, as permitted by the rating agencies rating the System Restoration Bonds. Investment earnings on REP cash deposits shall be considered part of such cash deposits so long as they remain on deposit with the Indenture Trustee. At the instruction of the Servicer, cash deposits will be remitted with investment earnings to the REP at the end of the term of the System Restoration Bonds unless otherwise utilized for the payment of the REP's obligations for System Restoration Charge payments. Once the deposit is no longer required, the Servicer shall promptly (but not later than 30 calendar days) instruct the Indenture Trustee to remit the amounts in the segregated accounts to the REP.

6. In the event that a REP or the POLR is billing customers for SRCs, the REP shall have the right to transfer the customer to the Provider of Last Resort (POLR) (or to another certified REP) or to direct the Servicer to terminate transmission and distribution service to the end-use customer for non-payment by the end-use customer pursuant to applicable Commission rules.

D. Billings by the Servicer to the REP or its Replacement (when applicable):

1. Applicable to all consumption subject to REP billing of SRCs.

2. Payments of SRCs are due 35 calendar days following each billing by the Servicer to the REP, without regard to whether or when the REP receives payment from its retail customers. The Servicer shall accept payment by electronic funds transfer (EFT), wire transfer (WT) and/or check. Payment will be considered received the date the EFT or WT is received by the Servicer, or the date the check clears. A 5% penalty is to be charged on amounts received after 35 calendar days; however, a 10-calendar-day grace period will be allowed before the REP is considered to be in default. A REP in default must comply with the provisions set forth in Paragraph 3 below. The 5% penalty will be a one-time assessment measured against the current amount overdue from the REP to the Servicer. The current amount consists of the total unpaid System Restoration Charges existing on the 36th calendar day after billing by the Servicer. Any and all such penalty payments will be made to the Indenture Trustee to be applied against System Restoration Charge obligations. A REP shall not be obligated to pay the overdue System Restoration Charges of another REP. If a REP agrees to assume the responsibility for the payment of

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

overdue System Restoration Charges as a condition of receiving the customers of another REP who has decided to terminate service to those customers for any reason, the new REP shall not be assessed the 5% penalty upon such System Restoration Charges; however, the prior REP shall not be relieved of the previously assessed penalties.

3. After the 10 calendar-day grace period (the 45th calendar day after the billing date) referred to in Paragraph 2 above, the Servicer shall have the option to seek recourse against any cash deposit, affiliate guarantee, surety bond, letter of credit, or combination thereof made by the REP, and avail itself of such legal remedies as may be appropriate to collect any remaining unpaid System Restoration Charges and associated penalties due the Servicer after the application of the REP's deposit or alternate form of credit support. In addition, a REP that is in default with respect to the requirements set forth in Paragraphs 4 and 5 of the previous section, Billings by the REP or its Replacement to End-Use Customers, and Paragraph 2 of this section shall select and implement one of the following options:

   (a) Allow the Provider of Last Resort (POLR) or a qualified REP of the customer's choosing to immediately assume the responsibility for the billing and collection of System Restoration Charges.

   (b) Immediately implement other mutually suitable and agreeable arrangements with the Servicer. It is expressly understood that the Servicer's ability to agree to any other arrangements will be limited by the terms of the servicing agreement and requirements of each of the rating agencies that have rated the System Restoration Bonds necessary to avoid a suspension, withdrawal, or downgrade of the ratings on the System Restoration Bonds.

   (c) Arrange that all amounts owed by retail customers for services rendered be timely billed and immediately paid directly into a lock-box controlled by the Servicer with such amounts to be applied first to pay System Restoration Charges before the remaining amounts are released to the REP. All costs associated with this mechanism will be borne solely by the REP.

   If a REP that is in default fails to immediately select and implement one of the foregoing options in (a), (b), or (c) or, after so selecting one of the foregoing options, fails to adequately meet its responsibilities thereunder, then the Servicer shall immediately implement option (a). Upon re-establishment of the

### 6.1.1.6.3 Schedule SRC - System Restoration Charge

requirements set forth in Paragraphs 4 and 5 of the previous section, Billings by the REP or its Replacement to End-Use Customers, and Paragraph 2 of this section and the payment of all past-due amounts and associated penalties, the REP will no longer be required to comply with this subsection.

4. The POLR will be required to meet the minimum credit rating and/or deposit/credit support requirements described in Paragraph 3 of the preceding section, Billings by the REP or its Replacement to End-Use Customers, in addition to any other standards that may be adopted by the Commission. If the POLR defaults or is not eligible to provide such services, responsibility for billing and collection of transition charges will immediately be transferred to and assumed by the Servicer until a new POLR can be named by the Commission or the customer requests the services of a certified REP. Retail customers may never be re-billed by the successor REP, the POLR, or Servicer for any amount of System Restoration Charges they have paid their REP (although future SRCs shall reflect REP and other system-wide charge-offs). Additionally, if the amount of the penalty detailed in Paragraph 2 of this section is the sole remaining past-due amount after the 45th day, the REP shall not be required to comply with (a), (b), or (c) above, unless the penalty is not paid within an additional 30 calendar days.

5. In the event the Servicer is billing customers for System Restoration Charges, the Servicer shall have the right to terminate transmission and distribution service for non-payment by end-use customers pursuant to the Commission's rules.

6. Notwithstanding Paragraph 2 of this section, the REPs will be allowed to hold back an allowance for charge-offs in their payments to the Servicer. Such charge-off rate will be recalculated each year in connection with the annual true-up procedure. In the initial year, the REPs will be allowed to remit payments based on the same system-wide charge off percentage then being used for the transition bonds issued by AEP Texas Central Transition Funding III LLC under the financing order issued in Docket No. 39931. On an annual basis in connection with the annual true-up adjustment process, the REP and the Servicer will be responsible for reconciling the amounts held back with amounts actually written off as uncollectible in accordance with the terms agreed to by the REP and the Servicer, provided that:

(a) The REP's right to reconciliation for write-offs will be limited to customers whose service has been permanently terminated and whose entire accounts (i.e., all amounts due the REP for its own account as well as the portion

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

representing System Restoration Charges) have been written off.

(b) The REP's recourse will be limited to a credit against future SRC payments unless the REP and the Servicer agree to alternative arrangements, but in no event will the REP have recourse to the SPE or its funds for such payments.

(c) The REP shall provide information on a timely basis to the Servicer so that the Servicer can include the REP's default experience and any subsequent credits into its calculation of the adjusted SRC Rates for the next SRC billing period and the REP's rights to credits will not take effect until after such adjusted SRC Rates have been implemented.

7. In the event that a REP disputes any amount of billed System Restoration Charges, the REP shall pay the disputed amount under protest according to the timelines detailed in Paragraph 2 of this section. The REP and Servicer shall first attempt to informally resolve the dispute, but if failing to do so within 30 calendar days, either party may file a complaint with the Commission. If the REP is successful in the dispute process (informal or formal), the REP shall be entitled to interest on the disputed amount paid to the Servicer at the Commission-approved interest rate. Disputes about the date of receipt of System Restoration Charge payments (and penalties arising thereof) will be handled in a like manner. Any interest paid by the Servicer on disputed amounts shall not be recovered through System Restoration Charges if it is determined that the Servicer's claim to the funds is clearly unfounded. No interest shall be paid by the Servicer if it is determined that the Servicer has received inaccurate metering data from another entity providing competitive metering services pursuant to PURA section 39.107.

8. If the Servicer is providing the metering, the metering data will be provided to the REP at the same time as the billing. If the Servicer is not providing the metering, the entity providing metering service(s) will be responsible for complying with Commission rules and ensuring that the Servicer and the REP receive timely and accurate metering data in order for the Servicer to meet its obligations under the Servicing Agreement and the Financing Order with respect to billing and true-ups.

**OTHER TERMS AND CONDITIONS**

If the customer, REP, or other entity which, under the terms of the Financing Order or PURA, may be obligated to pay or collect the SRCs, pays only a portion of its bill, a pro-rata share amount of

## 6.1.1.6.3 Schedule SRC - System Restoration Charge

System Restoration Charge revenues shall be deemed to be collected. In the event of any such shortfall, the amount paid shall first be apportioned between the system restoration charges and other fees and charges owed to the Company or any successor, other than late fees, ratably based on the amount owed for System Restoration Charges and the amount owed for other fees and charges (including system restoration charges owed for system restoration bonds), and second, any remaining portion of such payment shall be allocated to late fees.

At least once each year, (i) the Company shall cause to be prepared and delivered to REPs and such customers a notice stating, in effect, that the Transition Property and the System Restoration Charges are owned by the SPE and not the Company; and (ii) each REP which bills System Restoration Charges shall cause to be prepared and delivered to such customers a notice stating, in effect, that the Transition Property and the System Restoration Charges are owned by the SPE and not the REP or the Company. Such notice shall be included either as an insert to or in the text of the bills delivered to such REPs or customers, as applicable, or shall be delivered to customers by electronic means or such other means as the Servicer or the REP may from time to time use to communicate with their respective customers.

AEP TEXAS - CENTRAL DIVISION
TARIFF FOR ELECTRIC DELIVERY SERVICE
Applicable: Certified Service Area previously served by AEP Texas Central Company
Chapter: 6 Section: 6.1.1
Section Title: Delivery System Charges
Revision: Original Effective Date: Bills Rendered on or after September 18, 2019

## 6.1.1.6.3.1 Rider SRC – System Restoration Charge Factors

**AVAILABILITY**

This schedule is applicable to billed energy consumption and demands of retail customers taking service from the Company during the term that this schedule is in effect, and to the facilities, premises, and loads of all other retail customers obligated to pay Rider SRC Charges as provided in Schedule SRC, Section 6.1.1.6.3. Terms defined in Schedule SRC that are used herein shall have the same meaning as set forth in Schedule SRC.

**RATE CLASSES**

For purposes of billing System Restoration Charge Rates (SRC Rates), each retail end-use customer will be designated as a customer belonging to one of five classes as identified by Schedule SRC.

**SYSTEM RESTORATION CHARGE RATES**

| System Restoration Charge Customer Class | SRC Rates | |
|---|---|---|
| Residential | $0.001455 | per kWh |
| Secondary Service Less Than or Equal to 10 kW | $0.001798 | per kWh |
| Secondary Service Greater Than 10 kW | $0.297415 | per Distribution Billing kW |
| Primary Service | $0.238983 | per Distribution Billing kW |
| Lighting Service | $0.008215 | per kWh |

The SRC Rates are multiplied by the kWh or kW, as applicable, read, estimated or determined during the billing month and will be applied to bills rendered on and after the effective date.

**SYSTEM RESTORATION CHARGE TRUE-UP**

The Restoration Charge Rates shall be determined in accordance with and are subject to the provisions set forth in the Financing Order and Schedule SRC. Not less than 15 days prior to the first billing cycle for the Company's September billing month and no less frequently than annually thereafter, the Company or successor Servicer will file a revision to Rider SRC setting forth the adjusted SRC Rates to be effective for the upcoming period. If made as a result of the annual true-up adjustment in Schedule SRC, the adjusted SRC Rates will become effective on the first billing cycle of the Company's September billing month. In accordance with Schedule SRC, an interim true-up is mandatory semi-annually (or quarterly after the final scheduled payment date of the last tranche of the system restoration bonds) if the Servicer forecasts that system restoration charge

## 6.1.1.6.3.1 Rider SRC – System Restoration Charge Factors

collections will be insufficient to make all scheduled payments of principal, interest and other amounts in respect of the System Restoration Bonds on a timely basis during the current or next succeeding payment period and/or or to replenish any draws upon the capital subaccount. Optional interim true-ups may also be made at any time as described in Schedule SRC. If an interim true-up adjustment is made pursuant to Schedule SRC, the Adjusted SRC Rates will be become effective on the first billing cycle of the Company's billing month that is not less than 15 days following the making of the interim true-up adjustment filing. In the event that the forecasted billing units for one or more of the System Restoration Charge customer classes for an upcoming period decreases by more than 10% of the threshold billing units set forth in the Financing Order, the Servicer shall make a true-up filing at least 90 days prior to the first billing cycle for the Company's September billing month.

# 6.1.1.6.5. Rider ADFIT – ADFIT Credit

## APPLICABILITY

Pursuant to Public Utility Commission of Texas Docket No. 49308, the ADFIT Credit is a negative charge to customers subject to Schedule SRC to provide customers the accumulated deferred federal income tax (ADFIT) benefits associated with Hurricane Harvey and other system restoration costs.

This schedule is applicable to billed energy consumption and demands of retail customers taking service from the Company during the term that this schedule is in effect, and to the facilities, premises, and loads of all other retail customers obligated to pay Rider SRC Charges as provided in Schedule SRC, Section 6.1.1.6.3. Terms defined in Schedule SRC that are used herein shall have the same meaning as set forth in Schedule SRC.

## TERM

This Rider ADFITC is effective beginning on the date Schedule SRC is effective and will remain in effect over the 10-year term of Schedule SRC.

## ADFIT ALLOCATION FACTORS

The ADFIT Allocation Factors are the same as the PBRAFs in Schedule SRC.

## ADFITC RATES

The ADFITC Credits to be applied beginning on the effective date of this Rider ADFITC are set out below. The ADFITC rate classes and billing units are the same as the classes and billing units in Rider SRC. In addition, ADFITC Credits are applicable to each customer which has New On-Site Generation as defined in Schedule SRC, and to customers in multiply-certificated areas who request to switch from AEP Texas to another service provider on or after the date of approval of the Financing Order in Docket No. 49308, as and to the extent Schedule SRC charges are applicable to such customers. ADFITC Credits to be applied in subsequent periods will be determined in the annual true-up process.

AEP TEXAS - CENTRAL DIVISION
TARIFF FOR ELECTRIC DELIVERY SERVICE
Applicable: Certified Service Area previously served by AEP Texas Central Company
Chapter: 6 Section: 6.1.1
Section Title: Delivery System Charges
Revision: Original Effective Date: Bills Rendered on or after September 18, 2019

## 6.1.1.6.5. Rider ADFIT – ADFIT Credit

| ADFITC Rate Class | ADFITC Rates | |
|---|---|---|
| Residential | ($0.000166) | per kWh |
| Secondary Service Less Than or Equal to 10 kW | ($0.000205) | per kWh |
| Secondary Service Greater Than 10 kW | ($0.033988) | per Distribution Billing kW |
| Primary Service | ($0.027311) | per Distribution Billing kW |
| Lighting Service | ($0.000939) | per kWh |

The ADFITC Rates are multiplied by the kWh or kW, as applicable, read, estimated or determined during the billing month and will be applied to bills rendered on and after the effective date.

**ADFITC TRUE-UP ADJUSTMENT**

ADFITC Charges shall be adjusted annually effective on each date that charges in Schedule SRC become effective. The ADFITC true-up will be performed at the same time, using the same methodology and billing determinants, as the Standard True-Up or Non-Standard True-Up for Rate Schedule SRC. The ADFITC Charges shall be adjusted to (1) correct any over-credit or under-credit of the amounts previously scheduled to be provided to customers and (2) reflect the amounts scheduled to be provided to customers during the period the adjusted ADFITC Charges are to be effective.

**OTHER TERMS AND CONDITIONS**

If the customer or REP pays only a portion of its bill, a pro-rata portion of ADFITC Charge credits will be credited equal to the pro-rata portion of Schedule SRC collected according to Schedule SRC.

PUC DOCKET NO. 39931
APPLICATION OF AEP TEXAS CENTRAL COMPANY FOR FINANCING ORDER

| PARTIES | REPRESENTATIVE/ADDRESS |
|---|---|
| PUBLIC UTILITY COMMISSION | ALEXANDER PETAK<br>PUBLIC UTILITY COMMISSION<br>1701 N CONGRESS AVE STE 8-110<br>PO BOX 13326<br>AUSTIN TX 78711<br>512-936-7377<br>512-936-7268 FAX |
| AEP TEXAS CENTRAL COMPANY | RHONDA COLBERT RYAN<br>MELISSA A. GAGE<br>AMERICAN ELECTRIC POWER SERVICE CORPORATION<br>400 WEST 15TH STREET SUITE 1520<br>AUSTIN TX 78701<br>512-481-3321<br>512-481-4591 (FAX)<br>Email: rcryan@aep.com<br>magage@aep.com<br><br>JOHN F. WILLIAMS<br>SCOTT OLSON<br>DUGGINS WREN MANN & ROMERO LLP<br>600 CONGRESS AVE SUITE 1900<br>AUSTIN TX 78701<br>512-744-9300<br>512-744-9399 FAX<br>Email: jwilliams@dwmrlaw.com<br>solson@dwmrlaw.com |
| ALLIANCE FOR RETAIL MARKETS | STEPHEN J. DAVIS<br>LAW OFFICES OF STEPHEN J. DAVIS<br>919 CONGRESS AVE STE 900<br>AUSTIN TX 78701<br>512-479-9995<br>512-479-9996 FAX<br>Email: davis@sjdlawoffices.com |

## CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing filing was served on all parties of record in this proceeding by facsimile, hand delivered, electronically mailed, or sent by United States first class mail on this 12 day of September, 2019.

Grieg Gullickson

# Filing Receipt

**Received - 2022-03-25 04:37:10 PM**
**Control Number - 52302**
**ItemNumber - 46**

DUGGINS
WREN
MANN &
ROMERO, LLP

One American Center
600 Congress
Suite 1900
Austin, TX 78701

P.O. Box 1149
Austin, TX 78767

p: 512.744.9300
f: 512.744.9399
www.dwmrlaw.com

March 25, 2022

Ms. Ana Trevino, Filing Clerk
Central Records
Public Utility Commission of Texas
1701 N. Congress Ave.
Austin, Texas 78701

RE: PUC Docket No. 52302 – *Application of Entergy Texas, Inc. for a Financing Order*

Dear Ms. Trevino:

Enclosed is the Issuance Advice Letter filed pursuant to Ordering Paragraph 6 of the Financing Order issued on January 14, 2022 in the above-captioned proceeding. Also included are the electronic spreadsheets with formulas supporting the schedules contained in the Issuance Advice Letter, as required by Ordering Paragraph 6.

The system restoration bonds were priced on March 24, 2022. Accordingly, this Issuance Advice Letter is timely filed by the end of the first business day after the pricing of the system restoration bonds, as required by Ordering Paragraph 6.

Sincerely,

Scott Olson

Scott Olson
Attorney for Entergy Texas, Inc.

cc: All Parties of Record

# ISSUANCE ADVICE LETTER

**March 25, 2022**

**Docket No. 52302**

**THE PUBLIC UTILITY COMMISSION OF TEXAS**

**SUBJECT: ISSUANCE ADVICE LETTER FOR SYSTEM RESTORATION BONDS**

Pursuant to the Financing Order adopted in *Application of Entergy Texas, Inc. for a Financing* Order, Docket No. 52302 (the "Financing Order"), ENTERGY TEXAS, INC. ("Applicant") hereby submits, no later than the end of the first business day after the pricing date of this series of System Restoration Bonds, the information referenced below. This Issuance Advice Letter is for the 2022 System Restoration Bonds, tranches A-1 thru A-2. Any capitalized terms not defined in this letter have the meanings ascribed to them in the Financing Order.

## PURPOSE

This filing establishes the following:

(a) the total amount of Qualified Costs being securitized;
(b) confirmation of compliance with issuance standards;
(c) the actual terms and structure of the System Restoration Bonds being issued;
(d) the initial System Restoration Charge for retail users; and
(e) the identification of the BondCo.

## QUALIFIED COSTS BEING SECURITIZED

The total amount of Qualified Costs being securitized (the "Securitized Qualified Costs") is presented in Attachment 1.

**COMPLIANCE WITH ISSUANCE STANDARDS**

The Financing Order requires Applicant to confirm, using the methodology approved therein, that the actual terms of the System Restoration Bonds result in compliance with the standards set forth in the Financing Order. These standards are:

1. The securitization of Qualified Costs will provide tangible and quantifiable benefits to ratepayers, greater than would be achieved absent the issuance of the System Restoration Bonds (See Attachment 2, Schedule D);

2. The amount securitized will not exceed the present value of the conventional revenue requirement over the life of the System Restoration Bonds associated with the Securitized Qualified Costs when the present value calculation is made using a discount rate equal to the proposed interest rate on the System Restoration Bonds (See Attachment 2, Schedule D);

3. The total amount of revenues to be collected under the Financing Order is less than the revenue requirement that would be recovered using conventional financing methods (See Attachment 2, Schedules C and D);

4. The System Restoration Bonds will be issued in one or more series comprised of one or more tranches having target final payment of 14 years and legal final maturities not exceeding 15 years from the date of issuance of such series (See Attachment 2, Schedule A);

5. The System Restoration Bonds may be issued with an original issue discount, additional credit enhancement, or arrangements to enhance marketability provided that the Applicant certifies that the original issue discount is reasonably expected to provide benefits greater than its cost; and

6. The structuring and pricing of the System Restoration Bonds is certified by the Applicant to result in the lowest System Restoration Charges Consistent with market conditions and the terms (including the amortization structure ordered by the Commission, if any) set out in the Financing Order (See Attachment 4).

## ACTUAL TERMS OF ISSUANCE

System Restoration Bond Series: Senior Secured System Restoration Bonds, Series 2022-A

System Restoration Bond Issuer: Entergy Texas Restoration Funding II, LLC

Trustee: The Bank of New York Mellon

Closing Date: April 1, 2022
Bond Ratings: Moody's Aaa, S&P AAA
Amount Issued $290,850,000
System Restoration Bond Up-Front Qualified Costs: See Attachment 1, Schedule B.
System Restoration Bond Ongoing Qualified Costs: See Attachment 2, Schedule B.

| Tranche | Coupon Rate | Tranche Size | Expected Weighted Average Life | Expected Final Payment | Legal Final Maturity |
|---|---|---|---|---|---|
| A-1 | 3.051% | $100,000,000 | 3.02 yrs | 12/15/2027 | 12/15/2028 |
| A-2 | 3.697% | $190,850,000 | 9.97 yrs | 12/15/2035 | 12/15/2036 |

| | |
|---|---|
| Effective Annual Weighted Average Interest Rate of the System Restoration Bonds: | 3.609% |
| Life of Series: | 15 years |
| Weighted Average Life of Series: | 7.58 years |
| Call provisions (including premium, if any): | |
| Target Amortization Schedule: | Attachment 2, Schedule A |
| Target Final Payment Dates: | Attachment 2, Schedule A |
| Legal Final Maturity Dates: | Attachment 2, Schedule A |
| Payments to Investors: | Semiannually Beginning December 15, 2022 |
| Initial annual Servicing Fee as a percent of the original System Restoration Bond principal balance: | 0.10% |

**INITIAL SYSTEM RESTORATION CHARGE**

Table I below shows the current assumptions for each of the variables used in the calculation of the initial System Restoration Charges.

| TABLE I | |
|---|---|
| **Input Values for Initial System Restoration Charges** | |
| Applicable period: from April 29, 2022 to April 29, 2023 | |
| Forecasted retail kWh/kW sales for the applicable period: | 11,413,666,470 kWh<br>24,055,747 kW |
| System Restoration Bond debt service for the applicable period: | $33,697,450 |
| Percent of billed amounts expected to be charged-off: | 0.30% |
| Forecasted % of Billing Paid in the Applicable Period: | 99.70% |
| Forecasted retail kWh/kW sales billed and collected for the applicable period: | 11,413,666,470 kWh<br>24,055,747 kW |
| Forecasted annual ongoing transaction expenses (Excluding System Restoration Bond principal and interest): | $587,555 |
| Initial System Restoration Bond outstanding balance: | $290,850,000 |
| Target System Restoration Bond outstanding balance as of June 15, 2023 | $269,737,348 |
| Total Periodic Billing Requirement for applicable period before Uncollectible Rates are added: | $33,697,450 |

Allocation of the PBR among customer classes: See Attachment 3.

Based on the foregoing, the initial System Restoration Charges calculated for retail users are as follows:

| TABLE II | |
|---|---|
| **Rate Class** | **Initial System Restoration Charge-2** |
| | |
| Residential | $0.00327/kWh |
| Small General Service | $0.00307/kWh |
| General Service | $0.00232/kWh |
| Large General Service | $0.00140/kWh |
| Large Industrial Power Service – Trans. & Distribution | $0.05228/kW |
| Large Industrial Power Service – Distribution Only | $0.47019/kW |
| Standby and Maintenance Service: | |
| Standby Service | $0.01621/kW |
| Maintenance Service | $0.01621/kW |
| Street and Outdoor Lighting | $0.01099/kWh |

**IDENTIFICATION OF SPE**

The owner of the Transition Property will be: Entergy Texas Restoration Funding II, LLC

**EFFECTIVE DATE**

In accordance with the Financing Order, the System Restoration Charge shall be automatically effective upon the Applicant's receipt of payment in the amount of $287,017,794[1] from Entergy Texas Restoration Funding II, LLC, following Applicant's execution and delivery to Entergy Texas Restoration Funding II, LLC of the Bill of Sale transferring Applicant's rights and interests under the Financing Order and other rights and interests that will become Transition Property upon transfer to Entergy Texas Restoration Funding II, LLC as described in the Financing Order.

---

[1] The total securitized qualified costs less the sum of up-front qualified costs and original issue discount of $3,832,206.

**NOTICE**

Copies of this filing are being furnished to the parties on the attached service list. Notice to the public is hereby given by filing and keeping this filing open for public inspection at Applicant's corporate headquarters.

**AUTHORIZED OFFICER**

The undersigned is an officer of Applicant and authorized to deliver this Issuance Advice Letter on behalf of Applicant.

Respectfully submitted,

ENTERGY TEXAS, INC.

By: ________________
Name: Steven C. McNeal
Title: Vice President and Treasurer

**ATTACHMENT 1**
**SCHEDULE A**
**CALCULATION OF SECURITIZED QUALIFIED COSTS**

| | |
|---|---|
| Securitizable balance to be securitized | $287,017,794 |
| Estimated Up-front Qualified Costs | $3,832,206 |
| **TOTAL SECURITIZED QUALIFIED COSTS** | **$290,850,000** |

**ATTACHMENT 1**
**SCHEDULE B**
**ESTIMATED UP-FRONT QUALIFIED COSTS**

| | |
|---|---|
| **Capped Up-Front Qualified Costs** | |
| Legal Fees (Company, Issuer, and Underwriter) | $1,525,000 |
| Accountant's Fees | $300,000 |
| Trustee's/Trustee Counsel's Fees and Expenses | $50,000 |
| Servicer's Set-up Costs | $50,000 |
| Printing/Edgarizing Expenses | $10,000 |
| Company Financial Advisor Fees & Expenses | $240,000 |
| BondCo Setup Costs | $6,000 |
| Company's Non-Legal Securitization Proceeding Costs & Expenses | $15,000 |
| Company's Miscellaneous Administrative Costs | $15,000 |
| Underwriter's Fees | $1,163,400 |
| Subtotal Up-Front Qualified Costs | $3,374,400 |
| **Lesser of Subtotal or Capped Up-Front Qualified Costs** | **$3,350,000** |
| | |
| **Uncapped Up-Front Costs** | |
| Commission's Financial Advisor's Fees & Expenses | $50,000 |
| Legal Fees & Expenses for Counsel to the Commission's Advisor | $ - |
| Original Issue Discount | $ - |
| Cost of Other Credit Enhancements | $ - |
| Rounding/Contingency | $81 |
| Rating Agency Fees | $400,000 |
| SEC Registration Fee | $32,125 |
| | |
| **TOTAL UP-FRONT QUALIFIED COSTS SECURITIZED** | **$3,832,206** |

**Note: Certain costs are subject to an aggregate $3,350,000 cap set forth in the Financing Order. Differences that result from the Estimated Up-front Qualified Costs securitized being more than the actual up-front costs incurred will be resolved through the true-up process described in the Financing Order. Differences that result from the Estimated Up-front Qualified Costs securitized being less than the actual up-front costs incurred may be resolved in a future proceeding as described in the Financing Order, provided that the total amount of capped costs may not be recovered in excess of the aggregate cap.**

**ATTACHMENT 2**
**SCHEDULE A**
**SYSTEM RESTORATION BOND REVENUE REQUIREMENT INFORMATION**

| TRANCHE A-1 | | | | |
|---|---|---|---|---|
| Payment Date | Principal Balance | Interest | Principal | Total Payment |
| | $100,000,000 | | | |
| 12/15/2022 | $87,743,419 | $2,152,650 | $12,256,581 | $14,409,231 |
| 6/15/2023 | $78,887,348 | $1,338,526 | $8,856,071 | $10,194,597 |
| 12/15/2023 | $69,908,222 | $1,203,426 | $8,979,126 | $10,182,553 |
| 6/15/2024 | $60,804,331 | $1,066,450 | $9,103,891 | $10,170,341 |
| 12/15/2024 | $51,573,942 | $927,570 | $9,230,390 | $10,157,960 |
| 6/15/2025 | $42,215,296 | $786,760 | $9,358,646 | $10,145,406 |
| 12/15/2025 | $32,726,611 | $643,994 | $9,488,684 | $10,132,679 |
| 6/15/2026 | $23,106,082 | $499,244 | $9,620,530 | $10,119,774 |
| 12/15/2026 | $13,351,875 | $352,483 | $9,754,207 | $10,106,690 |
| 6/15/2027 | $3,462,134 | $203,683 | $9,889,741 | $10,093,424 |
| 12/15/2027 | - | $52,815 | $3,462,134 | $3,514,949 |

| TRANCHE A-2 | | | | |
|---|---|---|---|---|
| Payment Date | Principal Balance | Interest | Principal | Total Payment |
| | $190,850,000 | | | |
| 12/15/2022 | $190,850,000 | $4,978,206 | - | $4,978,206 |
| 6/15/2023 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 12/15/2023 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 6/15/2024 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 12/15/2024 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 6/15/2025 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 12/15/2025 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 6/15/2026 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 12/15/2026 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 6/15/2027 | $190,850,000 | $3,527,862 | - | $3,527,862 |
| 12/15/2027 | $184,284,974 | $3,527,862 | $6,565,026 | $10,092,888 |
| 6/15/2028 | $174,103,322 | $3,406,508 | $10,181,652 | $13,588,160 |
| 12/15/2028 | $163,756,676 | $3,218,300 | $10,346,646 | $13,564,946 |
| 6/15/2029 | $153,242,363 | $3,027,042 | $10,514,313 | $13,541,355 |
| 12/15/2029 | $142,557,666 | $2,832,685 | $10,684,698 | $13,517,383 |
| 6/15/2030 | $131,699,823 | $2,635,178 | $10,857,843 | $13,493,022 |
| 12/15/2030 | $120,666,028 | $2,434,471 | $11,033,794 | $13,468,266 |
| 6/15/2031 | $109,453,431 | $2,230,512 | $11,212,597 | $13,443,109 |
| 12/15/2031 | $98,059,134 | $2,023,247 | $11,394,297 | $13,417,544 |

| | | | | |
|---|---|---|---|---|
| 6/15/2032 | $86,480,192 | $1,812,623 | $11,578,942 | $13,391,565 |
| 12/15/2032 | $74,713,614 | $1,598,586 | $11,766,579 | $13,365,165 |
| 6/15/2033 | $62,756,358 | $1,381,081 | $11,957,256 | $13,338,337 |
| 12/15/2033 | $50,605,335 | $1,160,051 | $12,151,023 | $13,311,075 |
| 6/15/2034 | $38,257,404 | $935,440 | $12,347,931 | $13,283,370 |
| 12/15/2034 | $25,709,375 | $707,188 | $12,548,029 | $13,255,217 |
| 6/15/2035 | $12,958,006 | $475,238 | $12,751,370 | $13,226,607 |
| 12/15/2035 | - | $239,529 | $12,958,006 | $13,197,534 |

Legal Final Maturity:

Tranche A-1 12/15/2028

Tranche A-2 12/15/2036

**ATTACHMENT 2**
**SCHEDULE B**
**ONGOING QUALIFIED COSTS**

| | **ANNUAL AMOUNT** |
|---|---|
| Ongoing Servicer Fees Fee (Entergy Texas as Servicer) (0.10% of initial System Restoration Bond principal amount) | $290,850 |
| Administration Fees^ | $100,000 |
| Accountants Fees^ | $110,000 |
| Legal Fees/Expenses for Company's/Issuer's Counsel ^ | $50,000 |
| Trustee's/Trustee's Counsel Fees & Expenses ^ | $10,000 |
| Independent Manager's Fees^ | $5,000 |
| Rating Agency Fees^ | $51,705 |
| Printing/Edgarization Expenses^ | $10,000 |
| Miscellaneous^ | $10,000 |
| Settlement Reduction^ | $(50,000) |
| | |
| **TOTAL PROJECTED ONGOING QUALIFIED COSTS (with Entergy Texas as Servicer)** | $587,555 |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of principal amount) | $1,745,100 |
| Other Servicing Fees (total of line marked with a ^ above) | $296,705 |
| **TOTAL PROJECTED ONGOING QUALIFIED COSTS (Third Party as Servicer)** | $2,041,805 |

**Note: Certain of the Ongoing Qualified Costs are subject to caps set forth in the Financing Order. The amounts shown for each category of operating expense on this attachment are the expected expenses for the first year of the System Restoration Bonds. System Restoration Charges will be adjusted at least annually to reflect any changes in Ongoing Qualified Costs through the true-up process described in the Financing Order.**

**ATTACHMENT 2**
**SCHEDULE C**
**CALCULATION OF SYSTEM RESTORATION CHARGES**

| Year | System Restoration Bond Payments[2] | Ongoing Qualified Costs[3] | Total Nominal System Restoration Charge Requirement[4] | Present Value of System Restoration Charges[5] |
|---|---|---|---|---|
| 1 | $19,387,436 | $293,777 | $19,681,214 | $19,164,379 |
| 2 | $27,432,874 | $587,555 | $28,020,429 | $26,334,326 |
| 3 | $27,384,026 | $587,555 | $27,971,580 | $25,372,834 |
| 4 | $27,333,810 | $587,555 | $27,921,364 | $24,445,176 |
| 5 | $27,282,189 | $587,555 | $27,869,744 | $23,550,171 |
| 6 | $27,229,124 | $587,555 | $27,816,678 | $22,686,678 |
| 7 | $27,153,106 | $587,555 | $27,740,660 | $21,836,700 |
| 8 | $27,058,738 | $587,555 | $27,646,293 | $21,004,467 |
| 9 | $26,961,288 | $587,555 | $27,548,842 | $20,201,456 |
| 10 | $26,860,653 | $587,555 | $27,448,207 | $19,426,648 |
| 11 | $26,756,730 | $587,555 | $27,344,285 | $18,679,059 |
| 12 | $26,649,412 | $587,555 | $27,236,967 | $17,957,742 |
| 13 | $26,538,588 | $587,555 | $27,126,142 | $17,261,780 |
| 14 | $26,424,142 | $587,555 | $27,011,697 | $16,590,289 |
| 15 | | | | |
| **Total** | $370,452,115 | $7,931,987 | $378,384,102 | $294,511,706 |

2 From Attachment 2, Schedule A.

3 From Attachment 2, Schedule B.

4 Sum of System Restoration Bond payments and ongoing costs.

5 The discount rate used is the weighted average effective annual interest rate of the System Restoration Bonds.

**ATTACHMENT 2**
**SCHEDULE D**
**COMPLIANCE WITH SUBCHAPTER G OF THE UTILITIES CODE**

Tangible & Quantifiable Benefits and Revenue Requirements Tests:[6]

| | **Conventional Financing** | **Securitization Financing**[7] | **Savings/(Cost) of Securitization Financing** |
|---|---|---|---|
| Nominal | $485.6 million | $377.7 million | $107.9 million |
| Present Value | $376 million | $291.6 million | $84.4 million |

[6] Calculated in accordance with the methodology cited in the Financing Order.

[7] From Attachment 2, Schedule C.

**ATTACHMENT 3**
**INITIAL ALLOCATION OF COSTS TO SRC-2 CLASSES**

| (1)<br><br>SRC-2 Class | (2)<br><br>Allocation Factors[8] | (3)<br><br>Periodic Billing Requirement (Including Uncollectible Rates by Class) | (4)<br><br>Billing Requirement per SRC-2 Class | (5)<br><br>Forecasted Billing Determinants | (6)<br><br>SRC-2 Period 1 Charge |
|---|---|---|---|---|---|
| Residential | 59.7869% | $33,798,576 | $20,184,639 | 6,166,476,592 | $0.00327/kWh |
| Small General Service | 4.1278% | $33,798,576 | $1,389,678 | 452,670,741 | $0.00307/kWh |
| General Service | 22.3979% | $33,798,576 | $7,535,902 | 3,253,334,031 | $0.00232/kWh |
| Large General Service | 6.0031% | $33,798,576 | $2,019,402 | 1,444,952,171 | $0.00140/kWh |
| Large Industrial Power Service – Trans. & Distribution | 4.5519% | $33,798,576 | $995,513 | 19,042,127 | $0.05228/kW |
| Large Industrial Power Service Distribution Only | 4.5519% | $33,798,576 | $534,687 | 1,137,173 | $0.47019/kW |
| Street and Outdoor Lighting | 3.1325% | $33,798,576 | $1,057,505 | 96,232,935 | $0.01099/kWh |
| | 100.00% | $33,798,576 | | | |

The remaining Periodic Billing Requirement will be collected from the Standby and Maintenance Service, which charges will be designed based on the methodology prescribed in the order in Docket No. 51997. Pursuant to that methodology, the initial SRC-2 charge for Standby service will be $0.01621 per kW and the initial SRC-2 charge for Maintenance service will be $0.01621 per kW for a total of $81,248.

[8] Determined in accordance with the methodology set forth in the Financing Order and Schedule SRC-2.

**ATTACHMENT 4**
**APPLICANT'S CERTIFICATION**

Entergy Texas, Inc.
2107 Research Forest Drive
The Woodlands, Texas 77380

Date: March 25, 2022

Public Utility Commission of Texas
1701 N. Congress Ave.
P.O. Box 13362
Austin, TX 78711-3326

Drexel Hamilton LLC
77 Water Street, Suite 201
New York, NY 10005

RE: *Application of Entergy Texas, Inc. for a Financing Order*, Docket No. 52302

ENTERGY TEXAS, INC. (the "Applicant") submits this Certification pursuant to Ordering Paragraph No. 6 of the Financing Order in *Application of Entergy Texas, Inc. for a Financing Order*, Docket No. 52302 (the "Financing Order"). All capitalized terms not defined in this letter have the meanings ascribed to them in the Financing Order.

In its issuance advice letter dated March 25, 2022, the Applicant has set forth the following particulars of the System Restoration Bonds:

Name of System Restoration Bonds: Senior Secured System Restoration Bonds, Series 2022-A
SPE: Entergy Texas Restoration Funding II, LLC
Closing Date: April 1, 2022
Amount Issued: $290,850,000
Expected Amortization Schedule: See Attachment 2, Schedule A to the Issuance Advice Letter
Distributions to Investors: Semiannually
Weighted Average Coupon Rate: 3.609%
Weighted Average Yield:[9] 3.751%

[9] The internal rate of return, calculated including all up-front and ongoing costs.

The following actions were taken in connection with the design, marketing, structuring and pricing of the bonds:

- Included credit enhancement in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount.

- Registered the System Restoration Bonds with the Securities and Exchange Commission to facilitate greater liquidity.

- Achieved preliminary Aaa/AAA ratings from two major rating agencies with final Aaa/AAA ratings as a condition of closing.

- Worked with the Commission's designated representative(s) to select underwriters that have relevant experience and execution capability.

- Provided the investor presentation, including term sheet, and preliminary prospectus by e-mail to prospective investors.

- Allowed sufficient time for investors to review the investor presentation and preliminary prospectus and to ask questions regarding the transaction.

- Arranged for the issuance of rating agency pre-sale reports during the marketing period.

- During the period that the System Restoration Bonds were marketed, held daily market update discussions with the underwriting team to discuss market conditions and develop strategy for pricing.

- Had multiple conversations with all of the members of the underwriting team before and during the marketing phase in which we stressed the requirements of the Financing Order.

- Developed and implemented a marketing plan designed to give each of the underwriters incentive to aggressively market the System Restoration Bonds to their customers, including both ABS and corporate bond investors, and to reach out to a broad base of potential investors, including investors who have not previously purchased this type of security.

- Provided potential investors with access to a recorded version of the investor presentation for viewing on repeated occasions at investors' convenience and gave daily updates on investor engagement to the Commission's designated representative.

- Adapted the System Restoration Bond offering to market conditions and investor demand at the time of pricing. Variables impacting the final structure of the transaction were evaluated including the length of average lives and maturity of the System Restoration Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order.

- Worked with the Commission's designated representative to develop bond allocations, underwriter compensation and preliminary price guidance designed to achieve lowest interest rates.

- Worked with Commission and underwriters (and each of our respective counsels) to finalize documentation in accordance with established standards for transaction of this sort and the terms of the financing order.

Based upon information reasonably available to the officers, agent, and employees of the Applicant, the Applicant hereby certifies that the structuring and pricing of the System Restoration Bond, as described in the issuance advice letter, will result in the lowest system restoration bond charges consistent with market conditions and the terms of the Financing Order (including the amortization structure, if any, ordered by the Commission), all within the meaning of Sections 39.302 and 36.401 of PURA.

ENTERGY TEXAS, INC.

By: ______________________
Name: Steven C. McNeal
Title: Vice President and Treasurer

The following files are not convertible:

Lain Exhibit REL-1-Allocation of P1 Bond Payment-03.25-Final.XLS
Lofton Exhibit APL-1.XLSX
Lofton Exhibit APL-2.XLSX
Schedule 1.XLSX
Schedule 2.XLSX
Schedule 3.XLSX
Schedule 4.XLSX
Schedule 6.XLSX
Schedule 8.XLSX
Schedule 9 - SRC-2 P1 Rates_03-25-Final.XLSX
Schedule 10.XLSX
Workpapers to APL Schedules.XLSX

Please see the ZIP file for this Filing on the PUC Interchange in order to access these files.

Contact centralrecords@puc.texas.gov if you have any questions.

Long Island Power Authority

Thomas Falcone
Chief Executive Officer and
Interim Chief Financial Officer

September 21, 2022

Utility Debt Securitization Authority
c/o Long Island Lighting Company, d/b/a LIPA
333 Earle Ovington Boulevard, Suite 403
Uniondale, New York 11553
Attention: Bobbi O'Connor General Counsel and
Secretary to the Board of Trustees

Long Island Power Authority
333 Earle Ovington Boulevard, Suite 403
Uniondale, New York 11551

Ladies and Gentlemen:

Pursuant to Section 3(5) of Part B of Chapter 173 of the State of New York Laws of 2013, as amended (the "Securitization Law"), the Long Island Lighting Company d/b/a LIPA, as initial Servicer, hereby files with you the accompanying Issuance Advice Letter, which has been confirmed by the Long Island Power Authority (the "Authority") and which shall constitute notice to you that the Authority has confirmed that the price described therein complies with the final Restructuring Cost Financing No. 6 that was approved by the Authority on May 18, 2022, pursuant to the Securitization Law.

Very truly yours,

Long Island Lighting Company
d/b/a LIPA, as Servicer

By: ______________________
Name: Thomas Falcone
Title: Chief Executive Officer and Interim Chief Financial Officer

cc: Robert Gurman, Acting Chair, Utility Debt Securitization Authority
Bruce Levy, Trustee, Utility Debt Securitization Authority

# ISSUANCE ADVICE LETTER

## September 21, 2022

## LONG ISLAND POWER AUTHORITY

## ORDER NO. 6

## ISSUANCE ADVICE LETTER FOR RESTRUCTURING BONDS

Pursuant to the Restructuring Cost Financing Order No. 6 (the "Financing Order") issued by the Authority on May 18, 2022, LIPA, as the initial servicer of the Bonds, hereby submits this Issuance Advice Letter with respect to the Bonds priced on September 16, 2022. Any capitalized terms not defined in this Issuance Advice Letter shall have the meanings ascribed to them in the Financing Order.

**PURPOSE:**

This filing sets forth the following:

(a) Terms of Issuance, including pricing and principal amount of the Bonds;

(b) The net proceeds from the sale of the Bonds and estimated Upfront Financing Costs;

(c) The initial Charge;

(d) In case of Bonds issued to refinance the Authority's debt or debt of the Securitization Authority, the Target Debt to be purchased, redeemed, repaid or defeased with the proceeds of the sale of the Restructuring Property to be purchased by the Securitization Authority with the net proceeds from the sale of such Bonds;

(e) In case of Bonds issued to finance System Resiliency Costs, a description of the System Resiliency Costs to be financed and the amount thereof;

(f) The expected savings to Consumers; and

(g) Confirmation of compliance with the requirements of the Financing Order.

**A. ACTUAL TERMS OF ISSUANCE**:

| | |
|---|---|
| **Issuer:** | Utility Debt Securitization Authority |
| **Total Amount Issued (Taxable):** | $53,585,000 |
| **Total Amount Issued (Non-Taxable):** | $882,070,000 |
| **Trustee:** | The Bank of New York Mellon |
| **Sale Date:** | September 16, 2022 |
| **Closing Date:** | September 29, 2022 |
| **Bond Ratings:** | S&P AAA (sf), Moody's Aaa (sf) |
| **Target Amortization Schedule:** | See **Schedule B** |
| **Call Provisions:** | The Series TE Bonds with a Final Maturity Date on or prior to December 15, 2034 are not subject to optional redemption prior to maturity at the option of the Issuer.<br><br>The Series TE Bonds with a Final Maturity Date on or after December 15, 2035 are subject to redemption at the option of the Issuer in whole or in part, in any order, from time to time on any Business Day on and after December 15, 2032 upon payment of the redemption price of 100% of the principal amount of the Series TE Bonds to be redeemed, together with accrued interest to the redemption date.<br><br>The Series T Bonds are subject to redemption prior to their Scheduled Maturity Date, at the option of the Issuer, as a whole or in part (and, if in part, from such maturities as the Issuer shall direct), on any date, at the Make-Whole Redemption Price for such Series T Bonds. The Make-Whole Redemption Price will be equal to the greater of 1) 100% of the Principal Amount of the Series T Bonds of such maturity to be redeemed, or 2) the sum of the present value of the remaining scheduled payments of principal of and interest on the Series T Bonds of such maturity to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series T Bonds are to be redeemed, discounted on a semi-annual basis to the date on which the Series T Bonds of such maturity are to be redeemed, assuming a 360-day year containing twelve 30-day months, at the applicable Treasury Rate, (i) plus 10 basis points (0.10%) for Tranche 1 of the Series T Bonds (ii) plus 20 basis points (0.20%) for Tranche 2 of the Series T Bonds, and (iii) plus 25 basis points (0.25%) for Tranche 3 of the Series T Bonds, plus in each case |

| | |
|---|---|
| | accrued interest on the Series T Bonds of such Tranche to be so redeemed to the redemption date. |
| **Payments to Holders:** | The Payment Dates for the Series TE and Series T Bonds shall be June 15 and December 15 of each year and the Final Maturity Date of such bonds, or, if any such date is not a Business Day, the next succeeding Business Day, commencing on December 15, 2022 and continuing until the earlier of repayment of the Series TE and Series T Bonds in full or the respective Final Maturity Date. |
| **Required Debt Service Reserve Level** | means, (a) as of any date of calculation occurring on or prior to November 15, 2022, an amount equal to the greater of (i) the amount of Semiannual Interest due on the December 15, 2022, Payment Date plus 0.5% of the aggregate principal amount of Bonds then outstanding minus the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation and (ii) $0, and (b) as of any date of calculation occurring after November 15, 2022, an amount equal to the greater of (i) 0.5% of the aggregate principal amount of Bonds then outstanding minus the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation and (ii) $0. For the avoidance of doubt, to the extent that no principal amount is shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to a date of calculation, the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation for purposes of calculating the Required Debt Service Reserve Level will be $0. |
| **Required Operating Reserve Level** | means, as of any date of calculation, an amount equal to 0.50% of the aggregate principal amount of the Bonds originally issued; provided, however, that if any Bonds are refunded in advance of their maturity as permitted by the Indenture, on and after the date that provision for the payment of the Bonds so refunded has been made pursuant to the Indenture the Required Operating Reserve Level shall be equal to 0.50% of the Outstanding Amount of the Bonds immediately after such date. |

The initial annual Servicing Fee as a percentage of the original Bond principal balance is 0.05%.

The principal amounts of each Tranche of the Bonds to be issued and sold by the Securitization Authority on September 29, 2022 are as follows:

| Tranche | Principal Amount | Scheduled Maturity Date* | Legal Final Maturity* | Interest Rate | Yield |
|---|---|---|---|---|---|
| T1 | $20,945,000 | 12/15/2023 | 12/15/2025 | 4.421% | 4.421% |
| T2 | 11,650,000 | 12/15/2029 | 12/15/2031 | 4.653 | 4.653 |
| T3 | 20,990,000 | 12/15/2037 | 12/15/2039 | 4.953 | 4.953 |
| TE-1-1 | 5,955,000 | 6/15/2023 | 6/15/2025 | 5.000 | 2.460 |
| TE-1-2 | 6,100,000 | 12/15/2023 | 12/15/2025 | 5.000 | 2.510 |
| TE-1-3 | 6,055,000 | 6/15/2024 | 6/15/2026 | 5.000 | 2.550 |
| TE-1-4 | 6,205,000 | 12/15/2024 | 12/15/2026 | 5.000 | 2.580 |
| TE-1-5 | 12,010,000 | 6/15/2025 | 6/15/2027 | 5.000 | 2.640 |
| TE-1-6 | 12,300,000 | 12/15/2025 | 12/15/2027 | 5.000 | 2.650 |
| TE-1-7 | 49,330,000 | 6/15/2026 | 6/15/2028 | 5.000 | 2.730 |
| TE-1-8 | 50,560,000 | 12/15/2026 | 12/15/2028 | 5.000 | 2.770 |
| TE-1-9 | 67,560,000 | 6/15/2027 | 6/15/2029 | 5.000 | 2.830 |
| TE-1-10 | 69,250,000 | 12/15/2027 | 12/15/2029 | 5.000 | 2.850 |
| TE-1-11 | 38,975,000 | 6/15/2028 | 6/15/2030 | 5.000 | 2.920 |
| TE-1-12 | 39,950,000 | 12/15/2028 | 12/15/2030 | 5.000 | 2.930 |
| TE-1-13 | 49,690,000 | 6/15/2029 | 6/15/2031 | 5.000 | 3.040 |
| TE-1-14 | 50,930,000 | 12/15/2029 | 12/15/2031 | 5.000 | 3.070 |
| TE-1-15 | 30,740,000 | 6/15/2030 | 6/15/2032 | 5.000 | 3.120 |
| TE-1-16 | 31,500,000 | 12/15/2030 | 12/15/2032 | 5.000 | 3.130 |
| TE-1-17 | 17,090,000 | 6/15/2031 | 6/15/2033 | 5.000 | 3.260 |
| TE-1-18 | 17,515,000 | 12/15/2031 | 12/15/2033 | 5.000 | 3.310 |
| TE-1-19 | 17,765,000 | 6/15/2032 | 6/15/2034 | 5.000 | 3.400 |
| TE-1-20 | 18,205,000 | 12/15/2032 | 12/15/2034 | 5.000 | 3.430 |
| TE-1-21 | 26,590,000 | 12/15/2033 | 12/15/2035 | 5.000 | 3.540 |
| TE-1-22 | 5,490,000 | 12/15/2034 | 12/15/2036 | 5.000 | 3.590 |
| TE-1-23 | 900,000 | 12/15/2035 | 12/15/2037 | 5.000 | 3.640 |
| TE-1-24 | 93,930,000 | 12/15/2036 | 12/15/2038 | 5.000 | 3.700 |
| TE-1-25 | 62,695,000 | 12/15/2037 | 12/15/2039 | 5.000 | 3.760 |
| TE-2-1 | 5,330,000 | 12/15/2038 | 12/15/2040 | 5.000 | 3.820 |
| TE-2-2 | 5,600,000 | 12/15/2039 | 12/15/2041 | 5.000 | 3.890 |
| TE-2-3 | 5,885,000 | 12/15/2040 | 12/15/2042 | 5.000 | 3.950 |
| TE-2-4 | 6,180,000 | 12/15/2041 | 12/15/2043 | 5.000 | 4.000 |
| TE-2-5 | 6,490,000 | 12/15/2042 | 12/15/2044 | 5.000 | 4.040 |
| TE-2-6 | 37,745,000 | 12/15/2047 | 12/15/2049 | 5.000 | 4.100 |
| TE-2-7 | 27,550,000 | 12/15/2050 | 9/15/2052 | 5.000 | 4.130 |

* If such date is not a Business Day, the next Business Day without additional interest.

The maximum scheduled principal and interest payments in any bond year on the Bonds, issued under Restructuring Cost Financing Order No. 6, is calculated to be $173,380,459.20, which is less than the expected aggregate maximum scheduled annual principal and interest payments of $700 million as set forth in said restructuring cost financing orders.

None of the Bonds will have a legal final maturity exceeding 30 years from the date of their issuance.

The final scheduled maturity of each series of Bonds shall be no later than the final scheduled maturity date of the Authority or Securitization Authority bonds to be purchased, redeemed, repaid or defeased with the proceeds of such series of Bonds.

The Bonds, taken as a whole, are expected to have the following weighted average yield and life:

| | |
|---|---|
| **Effective Annual Weighted Average Yield on the Bonds:** | 3.52% |
| **Expected Weighted Average Life of Issuance:** | 9.3 yrs |

## B. NET PROCEEDS: UPFRONT FINANCING COSTS:

The net proceeds from the sale of the Bonds are as follows:

| | | **AMOUNT** |
|---|---|---|
| 1 | **Gross Proceeds** | $1,046,902,794 |
| 2 | Funding of debt service reserve account | 14,518,415 |
| 3 | Funding of operating reserve account | 4,678,275 |
| 4 | Nixon Peabody LLP - Disclosure Counsel | 240,000 |
| 5 | Hawkins Delafield & Wood LLP - Bond Counsel | 335,000 |
| 6 | KPMG - Independent Accountant | 100,000 |
| 7 | Moody's Investor Service - Rating Agency | 538,002 |
| 8 | Standard & Poor's - Rating Agency | 538,002 |
| 9 | Fitch Ratings - Rating Agency | 100,000 |
| 10 | Miscellaneous | 65,552 |
| 11 | Precision Analytics - Verification Agent | 3,000 |
| 12 | ImageMaster – Printer | 5,000 |
| 13 | LIPA – Servicer | 50,000 |
| 14 | Secure Share Network - 17g-5 Website | 5,000 |
| 15 | The Bank of New York Mellon - Trustee | 15,000 |
| 16 | Norton Rose Fulbright - Underwriter Counsel | 200,000 |
| 17 | Underwriter Fees and Expenses | 3,672,663 |
| 18 | Buchanan Ingersoll & Rooney PC - Trustee's Counsel | 12,500 |
| 19 | Dealer Manager Fee | 1,648,225 |
| 20 | Globic | 59,732 |
| 21 | Kestrel - Green Bonds | 25,000 |
| 22 | The Bank of New York Mellon - Escrow Agent | 10,000 |
| 23 | **Total estimated Upfront Financing Costs (Sum of Lines 2 through 21)** | 26,819,366 |
| 24 | **Net Proceeds (Line 1 – Line 22)** | $1,020,083,429 |

## INITIAL CHARGE:

The initial Charge, calculated pursuant to the Financing Order, is $0.004820 /kWh.

The table below shows the current assumptions for variables used in the calculation of the initial Charge.

**Input Values For Initial Charge**

| | |
|---|---|
| Applicable period: from October 1, 2022 to May 14, 2023 | |
| Forecasted retail kWh sales for the applicable period: | 10,466,105,533 |
| Scheduled Bond payments and estimated other Ongoing Financing Costs for the applicable period: | $40,039,291 |
| Percent of billed amounts expected to be charged-off: | 0.40% |
| Forecasted % of billed amounts paid during the applicable period: | 79.37% |
| Forecasted retail kWh sales billed and collected during the applicable period: | 8,306,455,064 |
| Total billing requirement for applicable period: | $40,200,091 |
| Initial Charge per kWh | $0.004820 |

## C. TARGET DEBT; SYSTEM RESILIENCY COSTS TO BE FUNDED:

The Net Proceeds from the sale of the Bonds will be used to purchase the Restructuring Property. The portions of the Target Debt to be purchased, redeemed, repaid or defeased with the proceeds of the sale of the Restructuring Property and the Restructuring Costs are set forth in **Schedule A-1** hereto.

The System Resiliency Costs to be financed with the Net Proceeds are set forth in **Schedule A-2** hereto.

## D. EXPECTED SAVINGS:

The expected Net Present Value Savings to Consumers, calculated pursuant to the Financing Order, the Securitization Debt Service based upon the scheduled payments on the Bonds specified in **Schedule B** hereto, the expected other Ongoing Financing Costs specified in **Schedule C** hereto, and the expected Charges specified in **Schedule D** hereto, and the Aggregate Expected Debt Service specified in **Schedule E** hereto, are as follows:

| | **Expected LIPA Debt Service** | **Securitization Debt Service**[1] | **Expected Savings** |
|---|---|---|---|
| **Net Present Value** | **$966,532,623.14** | **$926,021,479.05** | **$40,511,144.09** |

In the case of Bonds issued to finance System Resiliency Costs, the expected Net Present Value Savings to Consumers, calculated pursuant to the Financing Order, the Securitization Debt Service based upon the scheduled payments on the Bonds specified in **Schedule B** hereto, the expected other Ongoing Financing Costs specified in **Schedule C** hereto, and the expected Charges

[1] Includes net impact of LIPA contributions and reserve funds.

specified in **Schedule D** hereto, and the Aggregate Expected Debt Service specified in **Schedule F** hereto, are as follows:

| | Assumed LIPA System Resiliency Debt Service | Securitization Debt Service | Expected Savings |
|---|---|---|---|
| **Net Present Value** | **$118,574,051.49** | **$116,452,058.31** | **$2,121,993.19** |

## E. BASIC DOCUMENTS:

Attached to this Issuance Advice Letter are forms of the Servicing Agreement, Administration Agreement, Indenture, and Sale Agreement to be executed and delivered in connection with the issuance of the Bonds.

[Signature Page follows]

Respectfully submitted:

LONG ISLAND LIGHTING COMPANY (LIPA),
as Servicer

By: ______________________________
Chief Executive Officer and Interim Chief
Financial Officer

[Signature Page to Issuance Advice Letter]

Thomas Falcone

**CONFIRMATION AND APPROVAL**

The undersigned Authority Designee, as and on behalf of the Authority, hereby (a) confirms that the pricing of the Bonds and the other matters described in foregoing Issuance Advice Letter comply with the Financing Order and (b) approves (i) the Restructuring Costs, the expected Upfront Financing Costs, the expected Ongoing Financing Costs described in the Issuance Advice Letter, and (ii) the forms of the Servicing Agreement, Administration Agreement, Indenture, and Sale Agreement attached to the Issuance Advice Letter.

LONG ISLAND POWER AUTHORITY

By: ______________________________
Chief Executive Officer and Interim Chief Financial Officer

**Schedule A-1**

# SUMMARY OF BONDS RETIRED

| Series | CUSIP | Amount to be Retired | Total Outstanding Principal Amount | Current/Legal Final Maturity | Interest Rate |
|---|---|---|---|---|---|
| 2013TE-7 | 91802RAE9 | $ 2,280,000 | $ 14,960,000 | 12/15/2026 | 5.000% |
| 2013TE-8 | 91802RAF6 | 14,285,000 | 25,130,000 | 12/15/2027 | 5.000 |
| 2013TE-9 | 91802RAG4 | 39,420,000 | 77,740,000 | 12/15/2028 | 5.000 |
| 2013TE-10 | 91802RAH2 | 112,075,000 | 190,640,000 | 12/15/2029 | 5.000 |
| 2013TE-11 | 91802RAJ8 | 79,795,000 | 178,425,000 | 12/15/2030 | 5.000 |
| 2013TE-12 | 91802RAK5 | 67,310,000 | 186,045,000 | 12/15/2031 | 5.000 |
| 2013TE-13 | 91802RAL3 | 62,315,000 | 73,015,000 | 12/15/2032 | 5.000 |
| 2013TE-14 | 91802RAM1 | 34,810,000 | 55,130,000 | 12/15/2033 | 5.000 |
| 2013TE-15 | 91802RAN9 | 36,050,000 | 45,130,000 | 12/15/2034 | 5.000 |
| 2013TE-16 | 91802RAP4 | 26,785,000 | 44,370,000 | 12/15/2035 | 5.000 |
| 2013TE-17 | 91802RAQ2 | 184,165,000 | 468,530,000 | 12/15/2041 | 5.000 |
| 2012B | 5426902E1 | 13,810,000 | 13,810,000 | 9/1/2023 | 5.000 |
| 2012B | 5426902F8 | 9,705,000 | 9,705,000 | 9/1/2024 | 5.000 |
| 2012B | 5426902G6 | 9,900,000 | 9,900,000 | 9/1/2025 | 5.000 |
| 2012B | 5426902H4 | 60,055,000 | 60,055,000 | 9/1/2026 | 5.000 |
| 2012B | 5426902J0 | 25,230,000 | 25,230,000 | 9/1/2027 | 5.000 |
| 2012B | 5426902K7 | 45,170,000 | 45,170,000 | 9/1/2029 | 5.000 |
| 1998A* | 542690CH3 | 3,415,390 | 3,415,390 | 12/1/2023 | 0.000 |
| 2000A* | 542690NW8 | 5,191,732 | 5,191,732 | 6/1/2023 | 0.000 |
| 2015B | 5426904Q2 | 2,635,000 | 2,635,000 | 9/1/2023 | 5.000 |
| 2017 | 542691AC4 | 7,060,000 | 7,060,000 | 9/1/2023 | 5.000 |

**Capital Appreciation Bonds. Par-amount reflects initial par-amount and excludes accreted interest*

| Series | CUSIP | Amount to be Retired | Total Outstanding Principal Amount | Current/Legal Final Maturity | Interest Rate |
|---|---|---|---|---|---|
| 2018 | 542691BE9 | 2,900,000 | 2,900,000 | 9/1/2023 | 5.000 |
| 2019A | 542691CA6 | 2,500,000 | 2,500,000 | 9/1/2023 | 5.000 |
| 2020A | 542691CT5 | 2,500,000 | 2,500,000 | 9/1/2023 | 5.000 |
| 2021A | 542691EA4 | 2,910,000 | 2,910,000 | 9/1/2023 | 5.000 |
| **TOTAL** | | **$852,272,122** | **$1,552,097,122** | | |

**Schedule A-2**

## SYSTEM RESILIENCY PROJECTS*

| **Lob** | **SOS ID** | **Corporate Category** | **Location** | **Investment Name** | **Classification** |
|---|---|---|---|---|---|
| T&D | 1891 | Storm Hardening | Various | Storm hardening program | Program |
| T&D | 1022 | Reliability | Fire Island Pines | Install New 23 kV Circuit to Ocean Beach Substation | Specific |
| T&D | 1541 | Reliability | East Garden City | Switchgear replacement | Specific |
| T&D | 1293 | Reliability | Various | Distribution circuit improvement program (CIP) | Program |
| T&D | 1332 | Reliability | Various | Transmission protection and controls upgrades | Program |
| T&D | 1269 | Reliability | Various | Distribution system improvements - services, branch lines & customer requests | Blanket |

*As more particularly described in LIPA's Capital Budget.

## SYSTEM RESILIENCY COSTS

| **2022** | | | **2023** | **2022 & 2023** |
|---|---|---|---|---|
| **Approved Budget** | **June YTD Actual** | **Balance** | **Preliminary Submission** | **Sum Of Resiliency Projects** |
| $137,399,000 | $63,224,819 | $74,174,181 | $147,439,861 | $221,614,042 |

**Schedule B**

# TARGET AMORTIZATION SCHEDULE

| | Principal Balance | Principal (A) | Interest (A) | Debt Service (A) |
|---|---|---|---|---|
| 9/29/2022 | $935,655,000 | $0 | $ 0 | $ 0 |
| 12/15/2022 | 935,655,000 | 0 | 9,840,140 | 9,840,140 |
| 6/15/2023 | 935,655,000 | 16,315,000 | 23,305,594 | 39,620,594 |
| 12/15/2023 | 919,340,000 | 16,685,000 | 22,927,711 | 39,612,711 |
| 6/15/2024 | 902,655,000 | 6,055,000 | 22,541,230 | 28,596,230 |
| 12/15/2024 | 896,600,000 | 6,205,000 | 22,389,855 | 28,594,855 |
| 6/15/2025 | 890,395,000 | 12,010,000 | 22,234,730 | 34,244,730 |
| 12/15/2025 | 878,385,000 | 12,300,000 | 21,934,480 | 34,234,480 |
| 6/15/2026 | 866,085,000 | 49,330,000 | 21,626,980 | 70,956,980 |
| 12/15/2026 | 816,755,000 | 50,560,000 | 20,393,730 | 70,953,730 |
| 6/15/2027 | 766,195,000 | 67,560,000 | 19,129,730 | 86,689,730 |
| 12/15/2027 | 698,635,000 | 69,250,000 | 17,440,730 | 86,690,730 |
| 6/15/2028 | 629,385,000 | 38,975,000 | 15,709,480 | 54,684,480 |
| 12/15/2028 | 590,410,000 | 39,950,000 | 14,735,105 | 54,685,105 |
| 6/15/2029 | 550,460,000 | 55,450,000 | 13,736,355 | 69,186,355 |
| 12/15/2029 | 495,010,000 | 56,820,000 | 12,360,098 | 69,180,098 |
| 6/15/2030 | 438,190,000 | 30,740,000 | 10,949,817 | 41,689,817 |
| 12/15/2030 | 407,450,000 | 31,500,000 | 10,181,317 | 41,681,317 |
| 6/15/2031 | 375,950,000 | 17,090,000 | 9,393,817 | 26,483,817 |
| 12/15/2031 | 358,860,000 | 17,515,000 | 8,966,567 | 26,481,567 |
| 6/15/2032 | 341,345,000 | 17,765,000 | 8,528,692 | 26,293,692 |
| 12/15/2032 | 323,580,000 | 18,205,000 | 8,084,567 | 26,289,567 |
| 6/15/2033 | 305,375,000 | 13,130,000 | 7,629,442 | 20,759,442 |
| 12/15/2033 | 292,245,000 | 13,460,000 | 7,301,192 | 20,761,192 |
| 6/15/2034 | 278,785,000 | 2,710,000 | 6,964,692 | 9,674,692 |
| 12/15/2034 | 276,075,000 | 2,780,000 | 6,896,942 | 9,676,942 |
| 6/15/2035 | 273,295,000 | 445,000 | 6,827,442 | 7,272,442 |
| 12/15/2035 | 272,850,000 | 455,000 | 6,816,317 | 7,271,317 |
| 6/15/2036 | 272,395,000 | 46,385,000 | 6,804,942 | 53,189,942 |
| 12/15/2036 | 226,010,000 | 47,545,000 | 5,645,317 | 53,190,317 |
| 6/15/2037 | 178,465,000 | 41,325,000 | 4,456,692 | 45,781,692 |
| 12/15/2037 | 137,140,000 | 42,360,000 | 3,426,003 | 45,786,003 |
| 6/15/2038 | 94,780,000 | 2,630,000 | 2,369,500 | 4,999,500 |
| 12/15/2038 | 92,150,000 | 2,700,000 | 2,303,750 | 5,003,750 |
| 6/15/2039 | 89,450,000 | 2,765,000 | 2,236,250 | 5,001,250 |
| 12/15/2039 | 86,685,000 | 2,835,000 | 2,167,125 | 5,002,125 |
| 6/15/2040 | 83,850,000 | 2,905,000 | 2,096,250 | 5,001,250 |
| 12/15/2040 | 80,945,000 | 2,980,000 | 2,023,625 | 5,003,625 |
| 6/15/2041 | 77,965,000 | 3,050,000 | 1,949,125 | 4,999,125 |
| 12/15/2041 | 74,915,000 | 3,130,000 | 1,872,875 | 5,002,875 |
| 6/15/2042 | 71,785,000 | 3,205,000 | 1,794,625 | 4,999,625 |
| 12/15/2042 | 68,580,000 | 3,285,000 | 1,714,500 | 4,999,500 |

| | Principal Balance | Principal (A) | Interest (A) | Debt Service (A) |
|---|---|---|---|---|
| 6/15/2043 | 65,295,000 | 3,370,000 | 1,632,375 | 5,002,375 |
| 12/15/2043 | 61,925,000 | 3,455,000 | 1,548,125 | 5,003,125 |
| 6/15/2044 | 58,470,000 | 3,540,000 | 1,461,750 | 5,001,750 |
| 12/15/2044 | 54,930,000 | 3,630,000 | 1,373,250 | 5,003,250 |
| 6/15/2045 | 51,300,000 | 3,720,000 | 1,282,500 | 5,002,500 |
| 12/15/2045 | 47,580,000 | 3,810,000 | 1,189,500 | 4,999,500 |
| 6/15/2046 | 43,770,000 | 3,905,000 | 1,094,250 | 4,999,250 |
| 12/15/2046 | 39,865,000 | 4,005,000 | 996,625 | 5,001,625 |
| 6/15/2047 | 35,860,000 | 4,105,000 | 896,500 | 5,001,500 |
| 12/15/2047 | 31,755,000 | 4,205,000 | 793,875 | 4,998,875 |
| 6/15/2048 | 27,550,000 | 4,315,000 | 688,750 | 5,003,750 |
| 12/15/2048 | 23,235,000 | 4,420,000 | 580,875 | 5,000,875 |
| 6/15/2049 | 18,815,000 | 4,530,000 | 470,375 | 5,000,375 |
| 12/15/2049 | 14,285,000 | 4,645,000 | 357,125 | 5,002,125 |
| 6/15/2050 | 9,640,000 | 4,760,000 | 241,000 | 5,001,000 |
| 12/15/2050 | 4,880,000 | 4,880,000 | 122,000 | 5,002,000 |
| **TOTAL** | | **$935,655,000** | **$434,436,207** | **$1,370,091,207** |

**EXPECTED SINKING FUND SCHEDULE –2022T**
**TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2023 | $20,945,000 | $10,360,000 | $10,585,000 |
| 12/15/2023 | $10,585,000 | $10,585,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T**
**TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2029 | $11,650,000 | $5,760,000 | $5,890,000 |
| 12/15/2029 | $5,890,000 | $5,890,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T**
**TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $20,990,000 | $10,365,000 | $10,625,000 |
| 12/15/2037 | $10,625,000 | $10,625,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 21**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2033 | $26,590,000 | $13,130,000 | $13,460,000 |
| 12/15/2033 | $13,460,000 | $13,460,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 22**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2034 | $5,490,000 | $2,710,000 | $2,780,000 |
| 12/15/2034 | $2,780,000 | $2,780,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 23**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2035 | $900,000 | $445,000 | $455,000 |
| 12/15/2035 | $455,000 | $455,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 24**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2036 | $93,930,000 | $46,385,000 | $47,545,000 |
| 12/15/2036 | $47,545,000 | $47,545,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 25**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $62,695,000 | $30,960,000 | $31,735,000 |
| 12/15/2037 | $31,735,000 | $31,735,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2038 | $5,330,000 | $2,630,000 | $2,700,000 |
| 12/15/2038 | $2,700,000 | $2,700,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2039 | $5,600,000 | $2,765,000 | $2,835,000 |
| 12/15/2039 | $2,835,000 | $2,835,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2040 | $5,885,000 | $2,905,000 | $2,980,000 |
| 12/15/2040 | $2,980,000 | $2,980,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 4**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2041 | $6,180,000 | $3,050,000 | $3,130,000 |
| 12/15/2041 | $3,130,000 | $3,130,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 5**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2042 | $6,490,000 | $3,205,000 | $3,285,000 |
| 12/15/2042 | $3,285,000 | $3,285,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 6**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2043 | $37,745,000 | $3,370,000 | $34,375,000 |
| 12/15/2043 | $34,375,000 | $3,455,000 | $30,920,000 |
| 6/15/2044 | $30,920,000 | $3,540,000 | $27,380,000 |
| 12/15/2044 | $27,380,000 | $3,630,000 | $23,750,000 |
| 6/15/2045 | $23,750,000 | $3,720,000 | $20,030,000 |
| 12/15/2045 | $20,030,000 | $3,810,000 | $16,220,000 |
| 6/15/2046 | $16,220,000 | $3,905,000 | $12,315,000 |
| 12/15/2046 | $12,315,000 | $4,005,000 | $8,310,000 |
| 6/15/2047 | $8,310,000 | $4,105,000 | $4,205,000 |
| 12/15/2047 | $4,205,000 | $4,205,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 7**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2048 | $27,550,000 | $4,315,000 | $23,235,000 |
| 12/15/2048 | $23,235,000 | $4,420,000 | $18,815,000 |
| 6/15/2049 | $18,815,000 | $4,530,000 | $14,285,000 |
| 12/15/2049 | $14,285,000 | $4,645,000 | $9,640,000 |
| 6/15/2050 | $9,640,000 | $4,760,000 | $4,880,000 |
| 12/15/2050 | $4,880,000 | $4,880,000 | $0 |

**Schedule C**

# ESTIMATED OTHER ONGOING FINANCING COSTS

| | Annual Amount |
|---|---|
| Ongoing Servicer Fee (LIPA as Servicer) | $467,827.50 |
| Bond Administration Fees | 100,000 |
| Administration Fees and Expenses | 100,000 |
| Legal Fees | 10,000 |
| Accounting Fees | 16,500 |
| Directors and Officers Insurance Fees | 55,000 |
| Miscellaneous | 5,000 |
| **TOTAL ESTIMATED OTHER ONGOING FINANCING COSTS** | $754,327.50 |

**Schedule D**

# SUMMARY OF EXPECTED CHARGES

| Date | Bond Payments (1) | Other Financing Costs (2) | Total Nominal Charge Requirements (3) | PV of Expected Charges (4) |
|---|---|---|---|---|
| 12/15/2022 | $ 9,840,139.62 | $159,246.92 | $9,999,386.53 | $9,926,683.22 |
| 12/15/2023 | 79,233,304.85 | 754,327.50 | 79,987,632.35 | 76,708,179.98 |
| 12/15/2024 | 57,191,084.20 | 754,327.50 | 57,945,411.70 | 53,681,657.89 |
| 12/15/2025 | 68,479,209.20 | 754,327.50 | 69,233,536.70 | 61,960,000.85 |
| 12/15/2026 | 141,910,709.20 | 754,327.50 | 142,665,036.70 | 123,339,016.31 |
| 12/15/2027 | 173,380,459.20 | 754,327.50 | 174,134,786.70 | 145,430,834.64 |
| 12/15/2028 | 109,369,584.20 | 754,327.50 | 110,123,911.70 | 88,846,560.19 |
| 12/15/2029 | 138,366,452.80 | 754,327.50 | 139,120,780.30 | 108,427,395.02 |
| 12/15/2030 | 83,371,134.70 | 754,327.50 | 84,125,462.20 | 63,337,732.68 |
| 12/15/2031 | 52,965,384.70 | 754,327.50 | 53,719,712.20 | 39,071,200.64 |
| 12/15/2032 | 52,583,259.70 | 754,327.50 | 53,337,587.20 | 37,475,244.59 |
| 12/15/2033 | 41,520,634.70 | 754,327.50 | 42,274,962.20 | 28,693,423.51 |
| 12/15/2034 | 19,351,634.70 | 754,327.50 | 20,105,962.20 | 13,182,932.63 |
| 12/15/2035 | 14,543,759.70 | 754,327.50 | 15,298,087.20 | 9,689,744.67 |
| 12/15/2036 | 106,380,259.70 | 754,327.50 | 107,134,587.20 | 65,553,054.42 |
| 12/15/2037 | 91,567,695.48 | 754,327.50 | 92,322,022.98 | 54,570,329.28 |
| 12/15/2038 | 10,003,250.00 | 754,327.50 | 10,757,577.50 | 6,142,621.79 |
| 12/15/2039 | 10,003,375.00 | 754,327.50 | 10,757,702.50 | 5,933,990.58 |
| 12/15/2040 | 10,004,875.00 | 754,327.50 | 10,759,202.50 | 5,733,178.12 |
| 12/15/2041 | 10,002,000.00 | 754,327.50 | 10,756,327.50 | 5,536,909.19 |
| 12/15/2042 | 9,999,125.00 | 754,327.50 | 10,753,452.50 | 5,347,358.92 |
| 12/15/2043 | 10,005,500.00 | 754,327.50 | 10,759,827.50 | 5,168,740.79 |
| 12/15/2044 | 10,005,000.00 | 754,327.50 | 10,759,327.50 | 4,992,896.94 |
| 12/15/2045 | 10,002,000.00 | 754,327.50 | 10,756,327.50 | 4,821,914.68 |
| 12/15/2046 | 10,000,875.00 | 754,327.50 | 10,755,202.50 | 4,657,599.35 |
| 12/15/2047 | 10,000,375.00 | 754,327.50 | 10,754,702.50 | 4,499,144.76 |
| 12/15/2048 | 10,004,625.00 | 754,327.50 | 10,758,952.50 | 4,348,000.51 |
| 12/15/2049 | 10,002,500.00 | 754,327.50 | 10,756,827.50 | 4,199,444.35 |
| 12/15/2050 | 10,003,000.00 | 754,327.50 | 10,757,327.50 | 4,056,953.67 |
| 12/15/2051 | 0.00 | 0.00 | 0.00 | 0.00 |
| **TOTAL** | **$1,370,091,206.64** | **$21,280,416.92** | **$1,391,371,623.56** | **$1,045,332,744.20** |

(1) From Schedule B.
(2) From Schedule C.
(3) Sum of Bond Payments and Ongoing Financing Costs.
(4) The discount rate used is the "all-in" true interest cost of the Bonds.

**Schedule E**

# PRIOR BOND DEBT SERVICE

## SUMMARY OF AGGREGATE DEBT SERVICE
## ATTRIBUTABLE TO THE DEBT TO BE PURCHASED, REDEEMED, REPAID OR DEFEASED ("RETIRED")

**Fixed Rate Bonds**

| Series | CUSIP | Par Amount | Maturity Date | Interest Rate | PV Expected Payments[1] |
|---|---|---|---|---|---|
| 2012B | 5426902E1 | $13,810,000 | 9/1/2023 | 5.000% | $14,047,556 |
| 2012B | 5426902F8 | 9,705,000 | 9/1/2024 | 5.000 | 10,007,716 |
| 2012B | 5426902G6 | 9,900,000 | 9/1/2025 | 5.000 | 10,342,553 |
| 2012B | 5426902H4 | 60,055,000 | 9/1/2026 | 5.000 | 63,523,178 |
| 2012B | 5426902J0 | 25,230,000 | 9/1/2027 | 5.000 | 27,004,947 |
| 2012B | 5426902K7 | 45,170,000 | 9/1/2029 | 5.000 | 49,428,240 |
| 2013TE | 91802RAE9 | 2,280,000 | 12/15/2024 | 5.000 | 2,384,137 |
| 2013TE | 91802RAF6 | 12,410,000 | 6/15/2025 | 5.000 | 13,060,534 |
| 2013TE | 91802RAF6 | 1,875,000 | 12/15/2025 | 5.000 | 1,985,718 |
| 2013TE | 91802RAG4 | 38,390,000 | 6/15/2026 | 5.000 | 40,907,010 |
| 2013TE | 91802RAG4 | 1,030,000 | 12/15/2026 | 5.000 | 1,104,125 |
| 2013TE | 91802RAH2 | 94,145,000 | 6/15/2027 | 5.000 | 101,512,592 |
| 2013TE | 91802RAH2 | 17,930,000 | 12/15/2027 | 5.000 | 19,444,022 |
| 2013TE | 91802RAJ8 | 79,795,000 | 6/15/2028 | 5.000 | 87,017,779 |
| 2013TE | 91802RAK5 | 67,310,000 | 6/15/2029 | 5.000 | 74,199,543 |
| 2013TE | 91802RAL3 | 36,055,000 | 6/15/2030 | 5.000 | 40,157,644 |
| 2013TE | 91802RAL3 | 26,260,000 | 12/15/2030 | 5.000 | 29,394,322 |
| 2013TE | 91802RAM1 | 27,225,000 | 6/15/2031 | 5.000 | 30,623,492 |
| 2013TE | 91802RAM1 | 7,585,000 | 12/15/2031 | 5.000 | 8,572,626 |
| 2013TE | 91802RAN9 | 22,285,000 | 6/15/2032 | 5.000 | 25,304,458 |
| 2013TE | 91802RAN9 | 13,765,000 | 12/15/2032 | 5.000 | 15,701,550 |
| 2013TE | 91802RAP4 | 21,910,000 | 6/15/2033 | 5.000 | 25,104,270 |
| 2013TE | 91802RAP4 | 4,875,000 | 12/15/2033 | 5.000 | 5,610,180 |
| 2013TE | 91802RAQ2 | 2,700,000 | 6/15/2034 | 5.000 | 3,120,485 |
| 2013TE | 91802RAQ2 | 2,770,000 | 12/15/2034 | 5.000 | 3,214,804 |
| 2013TE | 91802RAQ2 | 435,000 | 6/15/2035 | 5.000 | 506,923 |
| 2013TE | 91802RAQ2 | 445,000 | 12/15/2035 | 5.000 | 520,658 |
| 2013TE | 91802RAQ2 | 46,375,000 | 6/15/2036 | 5.000 | 54,472,741 |
| 2013TE | 91802RAQ2 | 47,535,000 | 12/15/2036 | 5.000 | 56,050,040 |
| 2013TE | 91802RAQ2 | 50,880,000 | 6/15/2037 | 5.000 | 60,220,121 |
| 2013TE | 91802RAQ2 | 33,025,000 | 12/15/2037 | 5.000 | 39,231,533 |

| | | | | | |
|---|---|---|---|---|---|
| 1998A[2] | 542690CH3 | 3,415,390 | 12/1/2023 | 0.000 | 12,450,608 |
| 2000A[2] | 542690NW8 | 5,191,732 | 6/1/2023 | 0.000 | 19,448,794 |
| 2015B | 5426904Q2 | 2,635,000 | 9/1/2023 | 5.000 | 2,680,327 |
| 2017 | 542691AC4 | 7,060,000 | 9/1/2023 | 5.000 | 7,181,444 |
| 2018 | 542691BE9 | 2,900,000 | 9/1/2023 | 5.000 | 2,949,885 |
| 2019A | 542691CA6 | 2,500,000 | 9/1/2023 | 5.000 | 2,543,004 |
| 2020A | 542691CT5 | 2,500,000 | 9/1/2023 | 5.000 | 2,543,004 |
| 2021A | 542691EA4 | 2,910,000 | 9/1/2023 | 5.000 | 2,960,057 |

[1]Discount rate is the All-In True Interest Cost of the Bonds

[2]Capital Appreciation Bonds

## Schedule F

# Assumed LIPA System Resiliency Debt Service

| Assumed LIPA System Resiliency Debt Service | | | | | |
|---|---|---|---|---|---|
| Year | Principal Balance | Principal | Interest | Debt Service | PV Debt Service |
| 9/29/2022 | $96,535,000 | | | | |
| 3/1/2023 | $96,535,000 | - | 2,037,961 | 2,037,961 | $2,008,180.45 |
| 9/1/2023 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,337,011.27 |
| 3/1/2024 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,296,624.33 |
| 9/1/2024 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,256,935.33 |
| 3/1/2025 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,217,932.22 |
| 9/1/2025 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,179,603.14 |
| 3/1/2026 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,141,936.44 |
| 9/1/2026 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,104,920.68 |
| 3/1/2027 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,068,544.60 |
| 9/1/2027 | $96,535,000 | - | 2,413,375 | 2,413,375 | $2,032,797.16 |
| 3/1/2028 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,997,667.48 |
| 9/1/2028 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,963,144.89 |
| 3/1/2029 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,929,218.91 |
| 9/1/2029 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,895,879.21 |
| 3/1/2030 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,863,115.67 |
| 9/1/2030 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,830,918.33 |
| 3/1/2031 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,799,277.41 |
| 9/1/2031 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,768,183.30 |
| 3/1/2032 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,737,626.53 |
| 9/1/2032 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,707,597.83 |
| 3/1/2033 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,678,088.06 |
| 9/1/2033 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,649,088.27 |
| 3/1/2034 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,620,589.64 |
| 9/1/2034 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,592,583.50 |
| 3/1/2035 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,565,061.35 |
| 9/1/2035 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,538,014.83 |
| 3/1/2036 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,511,435.70 |
| 9/1/2036 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,485,315.90 |
| 3/1/2037 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,459,647.50 |
| 9/1/2037 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,434,422.67 |
| 3/1/2038 | $96,535,000 | - | 2,413,375 | 2,413,375 | $1,409,633.77 |
| 9/1/2038 | $96,535,000 | 5,450,000 | 2,413,375 | 7,863,375 | $4,513,564.25 |
| 3/1/2039 | $91,085,000 | - | 2,277,125 | 2,277,125 | $1,284,477.99 |
| 9/1/2039 | $91,085,000 | 5,720,000 | 2,277,125 | 7,997,125 | $4,433,052.10 |
| 3/1/2040 | $85,365,000 | - | 2,134,125 | 2,134,125 | $1,162,566.91 |
| 9/1/2040 | $85,365,000 | 6,010,000 | 2,134,125 | 8,144,125 | $4,359,851.44 |
| 3/1/2041 | $79,355,000 | - | 1,983,875 | 1,983,875 | $1,043,688.07 |
| 9/1/2041 | $79,355,000 | 6,310,000 | 1,983,875 | 8,293,875 | $4,287,884.28 |
| 3/1/2042 | $73,045,000 | - | 1,826,125 | 1,826,125 | $927,780.47 |
| 9/1/2042 | $73,045,000 | 6,625,000 | 1,826,125 | 8,451,125 | $4,219,474.87 |
| 3/1/2043 | $66,420,000 | - | 1,660,500 | 1,660,500 | $814,726.63 |
| 9/1/2043 | $66,420,000 | 6,955,000 | 1,660,500 | 8,615,500 | $4,154,154.80 |
| 3/1/2044 | $59,465,000 | - | 1,486,625 | 1,486,625 | $704,421.78 |
| 9/1/2044 | $59,465,000 | 7,305,000 | 1,486,625 | 8,791,625 | $4,093,828.59 |
| 3/1/2045 | $52,160,000 | - | 1,304,000 | 1,304,000 | $596,715.40 |
| 9/1/2045 | $52,160,000 | 7,670,000 | 1,304,000 | 8,974,000 | $4,035,569.90 |
| 3/1/2046 | $44,490,000 | - | 1,112,250 | 1,112,250 | $491,530.39 |
| 9/1/2046 | $44,490,000 | 8,050,000 | 1,112,250 | 9,162,250 | $3,979,048.71 |
| 3/1/2047 | $36,440,000 | - | 911,000 | 911,000 | $388,798.56 |
| 9/1/2047 | $36,440,000 | 8,455,000 | 911,000 | 9,366,000 | $3,928,163.73 |
| 3/1/2048 | $27,985,000 | - | 699,625 | 699,625 | $288,356.60 |
| 9/1/2048 | $27,985,000 | 8,880,000 | 699,625 | 9,579,625 | $3,880,093.99 |
| 3/1/2049 | $19,105,000 | - | 477,625 | 477,625 | $190,112.18 |
| 9/1/2049 | $19,105,000 | 9,320,000 | 477,625 | 9,797,625 | $3,832,417.90 |
| 3/1/2050 | $9,785,000 | - | 244,625 | 244,625 | $94,033.38 |
| 9/1/2050 | $9,785,000 | 9,785,000 | 244,625 | 10,029,625 | $3,788,742.17 |
| | | **$96,535,000.00** | **$109,087,586.11** | **$205,622,586.11** | **$118,574,051.49** |

**Attachment 1**

# SERVICING AGREEMENT

UTILITY DEBT SECURITIZATION AUTHORITY

as Bond Issuer

AND

LONG ISLAND LIGHTING COMPANY

as Servicer

# RESTRUCTURING PROPERTY SERVICING AGREEMENT

Dated as of September 29, 2022

# TABLE OF CONTENTS

This RESTRUCTURING PROPERTY SERVICING AGREEMENT, dated as of September 29, 2022, is made by and between Utility Debt Securitization Authority, a New York public authority (the "Bond Issuer"), and the Long Island Lighting Company, a New York corporation doing business under the name of LIPA ("LIPA"), as Servicer.

## RECITALS

WHEREAS the Servicer is willing to service the Restructuring Property purchased from the Seller by the Bond Issuer; and

WHEREAS the Bond Issuer, in connection with ownership of Restructuring Property, desires to engage the Servicer to carry out the functions described herein.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the parties hereto agree as follows:

## ARTICLE I

## DEFINITIONS

Section 1.01 Definitions. Capitalized terms used but not otherwise defined herein have the meanings assigned to them in Appendix A hereto.

Section 1.02 Other Definitional Provisions.

(a) "Agreement" means this Restructuring Property Servicing Agreement, together with all Exhibits, Schedules, Appendices and Annexes hereto, as the same may be amended, supplemented or otherwise modified from time to time.

(b) Non-capitalized terms used herein which are defined in Part B of Chapter 173 of the State of New York Laws of 2013, as amended (the "Statute"), as the context requires, have the meanings assigned to such terms in the Statute, but without giving effect to amendments to the Statute after the date hereof which have a material adverse effect on the Bond Issuer or the Bondholders.

(c) All terms defined in this Agreement shall have the defined meanings when used in any certificate or other document made or delivered pursuant hereto unless otherwise defined therein.

(d) The words "hereof," "herein," "hereunder" and words of similar import, when used in this Agreement, shall refer to this Agreement as a whole and not to any particular provision of this Agreement; Section, Schedule, Exhibit, Appendix and Annex references contained in this Agreement are references to Sections, Schedules, Exhibits, Appendices and Annexes in or to this Agreement unless otherwise specified; and the term "including" shall mean "including without limitation".

(e) The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter forms of such terms.

## ARTICLE II

## APPOINTMENT AND AUTHORIZATION

Section 2.01 Appointment of Servicer; Acceptance of Appointment. The Bond Issuer hereby appoints the Servicer, and the Servicer hereby accepts such appointment, to perform the Servicer's obligations pursuant to this Agreement on behalf of and for the benefit of the Bond Issuer in accordance with the terms of this Agreement. This appointment and the Servicer's acceptance thereof may not be revoked except in accordance with the express terms of this Agreement.

Section 2.02 Authorization. With respect to all or any portion of the Restructuring Property, the Servicer is hereby authorized and empowered by the Bond Issuer to:

(a) execute and deliver, on behalf of itself and/or the Bond Issuer, as the case may be, any and all instruments, documents or notices, and

(b) on behalf of itself and/or the Bond Issuer, as the case may be, make any filing and participate in proceedings of any kind with any governmental authorities, including with the Authority.

The Bond Issuer shall execute and furnish the Servicer with such documents as have been prepared by the Servicer for execution by the Bond Issuer, and with such other documents as may be in the Bond Issuer's possession, as the Servicer may determine to be necessary or appropriate to enable it to carry out its servicing and administrative duties hereunder. Upon the Servicer's written request, the Bond Issuer shall furnish the Servicer with any powers of attorney or other documents necessary or appropriate to enable the Servicer to carry out its duties hereunder.

Section 2.03 Dominion and Control Over the Restructuring Property. Notwithstanding any other provision herein, the Bond Issuer shall have dominion and control over the Restructuring Property, and the Servicer, in accordance with the terms hereof, is acting solely as the servicing agent and custodian for the Bond Issuer with respect to the Restructuring Property and the Restructuring Property Documentation. The Servicer shall not take any action with respect to the Restructuring Property that is not authorized by this Agreement or that shall impair the rights of the Bond Issuer or the Bond Trustee in the Restructuring Property, in each case unless such action is required by applicable law.

## ARTICLE III

## BILLING SERVICES

Section 3.01 Duties of Servicer. The Servicer, as agent for the Bond Issuer, shall have the following duties:

(a) Duties of Servicer Generally. The Servicer will manage, service, administer and make collections in respect of the Charge. The Servicer's duties will include:

(i) obtaining meter reads, calculating electricity usage and billing the Charge in accordance with the Financing Order and collecting (from Customers and Third Parties, as applicable) all Charge Collections;

(ii) responding to inquiries by Customers, Third Parties, the Authority, or any federal, local or other State governmental authority with respect to the Charge;

(iii) delivering bills to customers and Third Parties, accounting for Charge Collections, investigating and resolving delinquencies, processing and depositing collections, making periodic remittances and furnishing periodic reports to the Bond Issuer, the Authority, the Bond Trustee and the Rating Agencies;

(iv) selling, as the agent for the Bond Issuer, as its interest may appear, defaulted or written off accounts in accordance with the Servicer's usual and customary practices for accounts of Customers for T&D Rates;

(v) taking action in connection with True-Up Adjustments as is set forth herein.

Anything to the contrary notwithstanding, the duties of the Servicer set forth in this Agreement shall be qualified in their entirety by the Statute, the Financing Order and any Authority Regulations, as in effect at the time such duties are to be performed. Without limiting the generality of this Section 3.01(a), in furtherance of the foregoing, the Servicer hereby agrees that it shall also have, and shall comply with, the duties and responsibilities set forth in Annex 1 which, among other things, relate to data acquisition, usage and bill calculation, billing, customer service functions, collections, payment processing and remittance.

(b) Notification of Laws and Regulations. The Servicer shall promptly notify the Bond Issuer, the Authority, the Bond Trustee and the Rating Agencies in writing of any laws or Authority Regulations hereafter promulgated that have a material adverse effect on the Servicer's ability to perform its duties under this Agreement.

(c) Other Information. Upon the reasonable request of the Bond Issuer, the Authority, the Administrator, the Bond Trustee, or any Rating Agency, the Servicer shall provide to the Bond Issuer, the Authority, the Bond Trustee or the Rating Agencies, as the case may be, any public financial information in respect of the Servicer, or any material information regarding the Restructuring Property to the extent it is reasonably available to the Servicer, as may be reasonably necessary and permitted by law for the Bond Issuer, the Authority, the Administrator, the Bond Trustee or the Rating Agencies to monitor the Servicer's performance hereunder. In addition, so long as any of the Bonds of any Tranche are outstanding, the Servicer shall provide to the Bond Issuer, the Authority, the Administrator and to the Bond Trustee, within a reasonable time after written request therefor, any information available to the Servicer or reasonably obtainable by it that is necessary to calculate the Charge.

Section 3.02 Collection and Allocation of the Charge.

(a) The Servicer shall use all reasonable efforts, consistent with its customary servicing procedures, to collect all amounts owed in respect of the Charge as and when the same shall become due and shall follow such collection procedures as it follows with respect to collection activities that the Servicer conducts for itself or others. The Servicer shall not change the amount of or reschedule the due date of any scheduled payment of the Charge, except as contemplated in this Agreement or as required by law or court or Authority Regulations; provided, however, that the Servicer may take any of the foregoing actions to the extent that such action would be in accordance with its customary billing and collection practices for T&D Rates. The Servicer shall enforce the obligations of any Third Parties providing billing and collection services with respect to the Charge.

(b) As specified in the Statute and the Financing Order, any amounts received from or on behalf of a Customer that represent a partial payment of unpaid Charges and any other charges payable by the Customer will be allocated pro rata between transition charges, including the Charges, and such other charges unless the Customer specifies that a greater proportion of such payment is to be allocated to transition charges, including the Charges, except that such other charges shall be reduced by the amount of any claims by such Customer of setoff, counterclaim, surcharge or defense for purposes of such calculation.

Section 3.03 Transfer of Charge Collections.

(a) On each Business Day, commencing on the first Business Day in November 2022 on which payments on bills sent out in October 2022 are received, the Servicer shall calculate the total Charge Collections estimated to have been received from or on behalf of Customers on such Business Day in respect of all previously billed Charges which have been deposited in the Allocation Account and that are required to be remitted from the Allocation Account to the Collection Account (the “Daily Remittance”). Each Daily Remittance shall be calculated according to the procedures set forth in Annex 2 and shall be remitted as soon as reasonably practicable but in any event no later than the second Business Day after such payments are estimated to have been received from the Customers. Not later than 9:00 a.m. New York time on each Business Day, the Servicer shall provide written notice to the Allocation Agent and the Bond Trustee of the amount that the Allocation Agent is required to remit to the Collection Account on such date (i.e., the Daily Remittance). The Servicer shall also, promptly upon receipt, remit to the Collection Account any other proceeds of the Collateral which it may have received from time to time.

(b) The Servicer agrees and acknowledges that it holds all Charge Collections collected by it and any other proceeds of the Collateral received by it for the benefit of the Bond Trustee and the Holders and that all such amounts will be remitted to the Collection Account or the Allocation Account in accordance with this Section 3.03 and Section 5.11 without any surcharge, fee, offset, charge or other deduction except as set forth in clause (c) below. Except as set forth in clause (c) below, the Servicer further agrees not to make any claim to reduce its obligation to remit or cause to be remitted all Charge Collections collected by it or deposited in the Allocation Account.

(c) Within fifteen days prior to the date any Adjustment Notice is filed with the Authority, the Servicer shall calculate the amount of any Remittance Shortfall or Excess Remittance for the Reconciliation Period, as provided in Section 6(d) of Annex 2. If a Remittance Shortfall exists, the Servicer shall cause the Allocation Agent to make a supplemental remittance from the Allocation Account to the Collection Account within two (2) Business Days after such calculation. If an Excess Remittance exists, the Servicer shall cause such Excess Remittance to be corrected as soon as practicable by (i) reducing the amount of each Daily Remittance from the Allocation Account until the balance of such Excess Remittance has been reduced to zero or (ii) causing payment of the amount of such Excess Remittance to the Servicer (for remittance to the LIPA Bond Trustee) from the General Subaccount or the Excess Funds Subaccount, if necessary. The results of any such reconciliation shall be reported in the next issued Monthly Servicer's Certificate.

(d) Unless otherwise directed to do so by the Bond Issuer, the Servicer shall be responsible for selecting Eligible Investments (as defined in the Indenture) in which the funds in the Collection Account shall be invested pursuant to Section 8.03 of the Indenture.

Section 3.04 Servicing and Maintenance Standards. The Servicer shall, on behalf of the Bond Issuer:

(a) manage, service, administer and make collections in respect of the Restructuring Property with reasonable care and in material compliance with applicable law, including all applicable Authority Regulations, using the same degree of care and diligence that the Servicer exercises with respect to billing and collection activities that the Servicer conducts for itself and others;

(b) follow customary standards, policies and procedures in performing its duties as Servicer that are customary in the electric distribution industry;

(c) use all reasonable efforts, consistent with its customary servicing procedures, to enforce and maintain the Bond Issuer's and the Bond Trustee's rights in respect of the Restructuring Property;

(d) calculate Charges in compliance with the Statute and the Financing Order;

(e) invoice Customers in accordance with the procedures set forth in Annex 2,

except where the failure to comply with any of the foregoing would not materially and adversely affect the Bond Issuer's or the Bond Trustee's interest in the Restructuring Property. The Servicer shall follow such customary and usual practices and procedures as it shall deem necessary or advisable in its servicing of the Restructuring Property, which, in the Servicer's judgment, may include the taking of legal action pursuant to Section 3.10 or otherwise. Notwithstanding the foregoing, the Servicer shall not change its customary and usual practices and procedures in any manner that would materially and adversely affect the Bond Issuer's or the Bond Trustee's interest in the Restructuring Property unless it shall have provided the Rating Agencies with prior written notice.

Section 3.05 Servicer's Certificates. The Servicer will provide to the Bond Issuer, the Authority and to the Bond Trustee the statements and certificates specified in Annex 1.

Section 3.06 Annual Statement as to Compliance. The Servicer shall deliver to the Bond Issuer, the Authority, the Bond Trustee and each Rating Agency, on or before March 31 of each year beginning March 31, 2023 to and including March 31 succeeding the retiring of the Bonds, an Officer's Certificate, stating that:

(a) a review of the activities of the Servicer (including any party to which the Servicer has subcontracted services under this Agreement) during the preceding calendar year (or relevant portion thereof in the case of the first such Officer's Certificate) and of its performance under this Agreement has been made under such officer's supervision, and

(b) to the best of such officers' knowledge, based on such review, the Servicer has fulfilled all its obligations under this Agreement throughout such period or, if there has been a default in the fulfillment of any such obligation, describing each such default and its status.

Section 3.07 Annual Independent Registered Public Accountants' Report.

(a) The Servicer shall cause a firm of Independent registered public accountants (which may provide other services to the Servicer or its affiliates) to prepare annually, and the Servicer shall deliver annually to the Bond Issuer, the Bond Trustee, the Rating Agencies, and the Authority, on or before March 31 of each year, commencing with 2023 to and including the March 31st succeeding the Final Maturity Date of the Bonds, a report addressed to the Servicer (the "Annual Accountant's Report"), which may be included as part of the Servicer's customary auditing activities, to the effect that such firm has performed certain procedures, agreed between the Servicer and such accountants, in connection with the Servicer's compliance with its obligations under this Agreement during the preceding twelve months ended December 31 (or, in the case of the first Annual Accountant's Report to be delivered on or before March 31, 2023, the period of time from the date of this Agreement until December 31, 2022), identifying the results of such procedures and including any exceptions noted. In the event such accounting firm requires the Bond Trustee to agree or consent to the procedures performed by such firm, the Bond Issuer shall direct the Bond Trustee in writing to so agree; it being understood and agreed that the Bond Trustee will deliver such letter of agreement or consent in conclusive reliance upon the direction of the Bond Issuer, and the Bond Trustee will not make any independent inquiry or investigation as to, and shall have no obligation or liability in respect of, the sufficiency, validity or correctness of such procedures.

(b) The Annual Accountant's Report shall also indicate that the accounting firm providing such report is independent of the Servicer in accordance with the New York Public Authorities Law or the Code of Professional Ethics of the American Institute of Certified Public Accountants, as then in effect.

Section 3.08 Restructuring Property Documentation. To assure uniform quality in servicing the Restructuring Property and to reduce administrative costs, the Servicer shall keep on file, in accordance with its customary procedures, all Restructuring Property Documentation, it being understood that the Servicer is acting solely as the servicing agent and custodian for the Bond Issuer with respect to the Restructuring Property Documentation.

Section 3.09 Computer Records: Audits of Documentation.

(a) Safekeeping. The Servicer shall maintain accurate and complete accounts, records and computer systems pertaining to the Restructuring Property and the Restructuring Property Documentation in accordance with its standard accounting procedures and in sufficient detail to permit reconciliation between payments or recoveries on (or with respect to) the Charge and the Charge Collections from time to time remitted to the Bond Trustee pursuant to Section 3.03 and to enable the Bond Issuer to comply with this Agreement and the Bond Indenture. The Servicer shall conduct, or cause to be conducted, periodic audits of the Restructuring Property Documentation held by it under this Agreement and of the related accounts, records and computer systems, in such a manner as shall enable the Bond Issuer and the Bond Trustee, as pledgee of the Bond Issuer, to verify the accuracy of the Servicer's record keeping. The Servicer shall promptly report to the Bond Issuer, the Authority, the Administrator, and the Bond Trustee any failure on the Servicer's part to hold the Restructuring Property Documentation and maintain its accounts, records and computer systems as herein provided and promptly take appropriate action to remedy any such failure. Nothing herein shall be deemed to require an initial review or any periodic review by the Bond Issuer or the Bond Trustee of the Restructuring Property Documentation. The Servicer's duties to hold the Restructuring Property Documentation on behalf of the Bond Issuer set forth in this Section 3.09, to the extent such Restructuring Property Documentation has not been previously transferred to a successor Servicer, shall terminate three years after the earlier of the date on which (i) the Servicer is succeeded by a successor Servicer pursuant to the provisions of this Agreement or (ii) no Bonds of any Tranche are outstanding.

(b) Maintenance of and Access to Records. The Servicer shall maintain the Restructuring Property Documentation at 333 Earle Ovington Blvd. Ste. 403, Uniondale, New York or at such other office as shall be specified to the Bond Issuer, the Authority and to the Bond Trustee by written notice not later than 30 days prior to any change in location. The Servicer shall permit the Bond Issuer, the Authority, the Administrator and the Bond Trustee or their respective duly authorized representatives, attorneys, agents or auditors at any time during normal business hours to inspect, audit and make copies of and abstracts from the Servicer's records regarding the Restructuring Property, the Charge and the Restructuring Property Documentation. The failure of the Servicer to provide access to such information as a result of an obligation or applicable law (including Authority Regulations) prohibiting disclosure of information regarding customers shall not constitute a breach of this Section 3.09(b).

Section 3.10 Defending Restructuring Property Against Claims. The Servicer shall institute and maintain any action or proceeding necessary to compel performance by the Authority or the State of New York of any of their obligations or duties under the Statute or the Financing Order with respect to the Restructuring Property, and the Servicer agrees to take such legal or administrative actions, including defending against or instituting and pursuing legal actions and appearing or testifying at hearings or similar proceedings, as may be reasonably necessary to block or overturn any attempts to cause a repeal of, modification of or supplement to the Statute or the Financing Order, as the case may be, or the rights of holders of Restructuring

Property that would be adverse to Bondholders. The costs of any such action reasonably allocated by the Servicer to the Restructuring Property shall be payable from Charge Collections as an Ongoing Financing Cost in accordance with the Bond Indenture.

The Servicer's obligations pursuant to this Section 3.10 shall survive and continue notwithstanding the fact that the payment of Ongoing Financing Costs pursuant to the Bond Indenture may be delayed (it being understood that the Servicer may be required to advance its own funds to satisfy its obligations under this Section 3.10).

## ARTICLE IV

## SERVICES RELATED TO TRUE-UP ADJUSTMENTS

Section 4.01 True-Up Adjustments. The Servicer shall perform the calculations and take the actions relating to adjusting the Charge, as set forth in Annex 1.

## ARTICLE V

## THE SERVICER

Section 5.01 Representations and Warranties of Servicer. The Servicer makes the following representations and warranties, as of the Closing Date, on which the Bond Issuer has and will rely in entering into this Agreement relating to the servicing of the Restructuring Property. The representations and warranties shall survive the execution and delivery of this Agreement, the sale of the Restructuring Property to the Bond Issuer and the pledge thereof to the Bond Trustee pursuant to the Bond Indenture.

(a) Organization and Good Standing. The Servicer is a corporation duly organized and in good standing under the laws of the State of New York, with the requisite corporate power and authority to own its properties as such properties are currently owned and to conduct its business as such business is now conducted by it, and has the requisite corporate power and authority to service the Restructuring Property and to hold the Restructuring Property and Restructuring Property Documentation as custodian.

(b) Due Qualification. The Servicer is duly qualified to do business, and has obtained all necessary licenses and approvals, in all jurisdictions in which the ownership or lease of property or the conduct of its business (including the servicing of the Restructuring Property as required by this Agreement) shall require such qualifications, licenses or approvals (except where the failure to so qualify or obtain such licenses and approvals would not be reasonably likely to have a material adverse effect on the Servicer's business, operations, assets, revenues or properties or adversely affect the servicing of the Restructuring Property).

(c) Power and Authority. The Servicer has the requisite corporate power and authority to execute and deliver this Agreement and to carry out its terms; and the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate action on the part of the Servicer.

(d) Binding Obligation. This Agreement constitutes a legal, valid and binding obligation of the Servicer enforceable against it in accordance with its terms, subject to applicable bankruptcy, receivership, insolvency, reorganization, moratorium, fraudulent transfer and other laws relating to or affecting creditors' rights generally from time to time in effect and to general principles of equity (including concepts of materiality, reasonableness, good faith and fair dealing), regardless of whether considered in a proceeding in equity or at law.

(e) No Violation. The consummation of the transactions contemplated by this Agreement and the fulfillment of the terms hereof do not: (i) conflict with or result in any breach of any of the terms and provisions of, nor constitute (with or without notice or lapse of time) a default under, the articles of incorporation or by-laws of the Servicer, or any material indenture, agreement or other instrument to which the Servicer is a party or by which it is bound; (ii) result in the creation or imposition of any Lien upon any of the Servicer's properties pursuant to the terms of any such indenture, agreement or other instrument; or (iii) violate any existing law or any existing order, rule or regulation applicable to the Servicer of any federal or state court or regulatory body, administrative agency or other governmental instrumentality having jurisdiction over the Servicer or its properties.

(f) Approvals. No approval, authorization, consent, order or other action of, or filing with, any federal or state court, regulatory body, administrative agency or other governmental instrumentality is required in connection with the execution and delivery by the Servicer of this Agreement, the performance by the Servicer of the transactions contemplated hereby or the fulfillment by the Servicer of the terms hereof, except those that have been obtained or made and those that the Servicer is required to make in the future pursuant to Article III or IV hereof.

(g) No Proceedings. There are no proceedings pending and, to the Servicer's knowledge, there are no proceedings threatened and no investigations pending or threatened, before any federal or state court, regulatory body, administrative agency or other governmental instrumentality having jurisdiction over the Servicer or its properties involving or relating to the Servicer, the Authority or the Bond Issuer or, to the Servicer's knowledge, any other Person: (i) asserting the invalidity of this Agreement; (ii) seeking to prevent the consummation of any of the transactions contemplated by this Agreement; or (iii) seeking any determination or ruling that might materially adversely affect the performance by the Servicer of its obligations under, or the validity or enforceability of, this Agreement.

(h) Reports and Certificates. Each report and certificate delivered in connection with the Issuance Advice Letter or delivered in connection with any filing made to the Authority by the Servicer with respect to the Charges or True-Up Adjustments will constitute a representation and warranty by the Servicer that each such report or certificate, as the case may be, is true and correct in all material respects; but to the extent any such report or certificate is based in part upon or contains assumptions, forecasts or other predictions of future events, the representation and warranty of the Servicer with respect thereto will be limited to the representation and warranty that such assumptions, forecasts or other predictions of future events are reasonable based upon historical performance (and facts known to the Servicer on the date such report or certificate is delivered).

Section 5.02 Indemnities of Servicer.

(a) The Servicer shall be liable in accordance herewith only to the extent of the obligations specifically undertaken by the Servicer under this Agreement.

(b) The Servicer shall indemnify the Bond Issuer and the Bond Trustee (for itself and on behalf of the Bondholders) and each of their respective trustees, members, managers, officers, directors, employees and agents for, and defend and hold harmless each such Person from and against, any and all Losses that may be imposed upon, incurred by or asserted against any such Person as a result of:

(i) the Servicer's willful misconduct or negligence in the performance of its duties or observance of its covenants under this Agreement or the Servicer's reckless disregard of its obligations and duties under this Agreement;

(ii) the Servicer's breach of any of its representations or warranties in this Agreement; and

(iii) litigation and related expenses relating to its status and obligations as Servicer,

provided, however, that the Servicer shall not be liable for any Losses resulting from the willful misconduct or gross negligence of any Person indemnified pursuant to this Section 5.02 (each, an "Indemnified Person") or resulting from a breach of a representation or warranty made by such Indemnified Person in any of the Basic Documents that gives rise to the Servicer's breach.

Promptly after receipt by an Indemnified Person of notice of its involvement in any action, proceeding or investigation, such Indemnified Person shall, if a claim for indemnification in respect thereof is to be made against the Servicer under this Section 5.02, notify the Servicer in writing of such involvement. Failure by an Indemnified Person to so notify the Servicer shall relieve the Servicer from the obligation to indemnify and hold harmless such Indemnified Person under this Section 5.02 only to the extent that the Servicer suffers actual prejudice as a result of such failure. With respect to any action, proceeding or investigation brought by a third party for which indemnification may be sought under this Section 5.02, the Servicer shall be entitled to assume the defense of any such action, proceeding or investigation. Upon assumption by the Servicer of the defense of any such action, proceeding or investigation, the Indemnified Person shall have the right to participate in such action or proceeding and to retain its own counsel (including local counsel), and the Servicer shall bear the reasonable fees, costs and expenses of such separate counsel. The Indemnified Person shall not settle or compromise or consent to the entry of any judgment with respect to any pending or threatened claim, action, suit or proceeding in respect of which indemnification may be sought under this Section 5.02 (whether or not the Servicer is an actual or potential party to such claim or action) unless the Servicer agrees in writing to such settlement, compromise or consent and such settlement, compromise or consent includes an unconditional release of the Servicer from all liability arising out of such claim, action, suit or proceeding.

(c) The Servicer shall indemnify the Bond Trustee and its respective officers, directors and agents for, and defend and hold harmless each such Person from and against, any and all Losses that may be imposed upon, incurred by or asserted against any such Person as a result of the acceptance or performance of the trusts and duties contained herein and in the Bond Indenture, except to the extent that any such Loss is due to the willful misconduct, bad faith or gross negligence of the Bond Trustee; provided, however, that the foregoing indemnity is extended to the Bond Trustee solely in its individual capacity and not for the benefit of the Bondholders or any other Person. Such amounts with respect to the Bond Trustee shall be deposited and distributed in accordance with the Bond Indenture.

(d) The Servicer's indemnification obligations under Section 5.02(b) and (c) for events occurring prior to the removal or resignation of the Bond Trustee or the termination of this Agreement shall survive the resignation or removal of the Bond Trustee or the termination of this Agreement and shall include reasonable costs, fees and expenses of investigation and litigation (including the Bond Issuer's and the Bond Trustee's reasonable attorneys' fees and expenses).

(e) Except to the extent expressly provided for in the Basic Documents (including the Servicer's claims with respect to the Servicing Fees), the Servicer hereby releases and discharges the Bond Issuer (including its trustees, officers, employees and agents, if any), and the Bond Trustee (including its respective officers, directors and agents) (collectively, the "Released Parties") from any and all actions, claims and demands whatsoever, which the Servicer shall or may have against any such Person relating to the Restructuring Property or the Servicer's activities with respect thereto other than any actions, claims and demands arising out of the willful misconduct, bad faith or gross negligence of the Released Parties.

(f) The Servicer will not indemnify any person for any loss, damages, liability, obligation, claim, action, suit or payment resulting solely from a downgrade in the ratings on the Bonds or for any consequential damages, including any loss of market value of the Bonds, resulting from any default or any downgrade of the ratings on the Bonds.

Section 5.03 Merger or Consolidation of, or Assumption of the Obligations of, Servicer. Any Person (a) into which the Servicer may be merged or consolidated, (b) which may result from any merger or consolidation to which the Servicer shall be a party or (c) which may succeed to the properties and assets of the Servicer substantially as a whole, which Person in any of the foregoing cases executes an agreement of assumption to perform every obligation of the Servicer under this Agreement, shall be the successor to the Servicer under this Agreement without the execution or filing of any document or any further act by any of the parties to this Agreement; provided, however, that (i) immediately after giving effect to such transaction, no representation or warranty made pursuant to Section 5.01 shall have been breached and no Servicer Default and no event which, after notice or lapse of time, or both, would become a Servicer Default shall have occurred and be continuing, (ii) the Servicer shall have delivered to the Bond Issuer and the Bond Trustee an Officer's Certificate stating that such consolidation, merger or succession and such agreement of assumption comply with this Section and that all conditions precedent provided for in this Agreement relating to such transaction have been complied with, (iii) the Servicer shall have delivered to the Bond Issuer and the Bond Trustee an Opinion of Counsel either (A) stating that, in the opinion of such counsel, all statutory filings to be made by the Servicer, including filings with the Authority pursuant to the Statute and filings under the applicable UCC, that are necessary fully to preserve and protect the interests of the

Bond Issuer and the Bond Trustee in the Restructuring Property have been executed and filed and reciting the details of such filings or (B) stating that, in the opinion of such counsel, no such action is necessary to preserve and protect such interests, (iv) the Rating Agencies shall have received prior written notice of such transaction and (v) the Servicer shall have delivered to the Bond Issuer, the Authority and the Bond Trustee an opinion of independent tax counsel (as selected by, and in form and substance reasonably satisfactory to, the Servicer, and which may be based on a ruling from the Internal Revenue Service) to the effect that, for federal income tax purposes, such consolidation or merger will not result in a material adverse federal income tax consequence to the Bond Issuer, the Bond Trustee or the then existing Bondholders.

The Servicer shall not consummate any transaction referred to in subclauses (a), (b) or (c) above except upon execution of the above described agreement of assumption and compliance with subclauses (i), (ii), (iii), (iv) and (v) above. When any Person acquires the properties and assets of the Servicer substantially as a whole and becomes the successor to the Servicer in accordance with the terms of this Section 5.03, then upon satisfaction of all of the other conditions of this Section 5.03, the Servicer shall automatically and without further notice be released from all its obligations hereunder.

Section 5.04 Assignment. The Servicer may assign any or all of its obligations hereunder to any successor if either (i) the Rating Agency Condition and any other condition specified in the Financing Order have been satisfied, or (ii) the Servicer is replaced by a successor pursuant to Section 5.03.

Section 5.05 Limitation on Liability of Servicer and Others. The Servicer shall not be liable to the Bond Issuer or the Bond Trustee, except as provided under this Agreement, for any action taken or for refraining from the taking of any action pursuant to this Agreement or for errors in judgment; provided, however, that this provision shall not protect the Servicer against any liability that would otherwise be imposed by reason of willful misconduct, bad faith or negligence in the performance of its duties or by reason of reckless disregard of obligations and duties under this Agreement. The Servicer and any director, officer, employee or agent of the Servicer may rely in good faith on the advice of counsel reasonably acceptable to the Bond Trustee or on any document of any kind, prima facie properly executed and submitted by any Person, respecting any matters arising under this Agreement. Except as provided in this Agreement, the Servicer shall not be under any obligation to appear in, prosecute or defend any legal action incidental to incidental to its duties to service the Restructuring Property in accordance with this Agreement or related to its obligation to pay indemnification, and that in its reasonable opinion may cause it to incur any expense or liability.

Section 5.06 LIPA Not to Resign as Servicer. Subject to the provisions of Sections 5.03 and 5.04, LIPA shall not resign from the obligations and duties hereby imposed on it as Servicer under this Agreement except upon a determination that LIPA's performance of its duties under this Agreement shall no longer be permissible under applicable law. Notice of any such determination permitting the resignation of LIPA shall be communicated to the Bond Issuer, the Authority, the Allocation Agent, the Bond Trustee and each Rating Agency at the earliest practicable time (and, if such communication is not in writing, shall be confirmed in writing at the earliest practicable time), and any such determination shall be evidenced by an Opinion of Counsel to such effect delivered to the Bond Issuer, the Authority, the Allocation

Agent and the Trustee concurrently with or promptly after such notice. No such resignation shall become effective until a successor Servicer has assumed the servicing obligations and duties hereunder of the Servicer in accordance with Section 6.04.

Section 5.07 Servicing Fee. The Bond Issuer agrees to pay the Servicer an annual servicing fee (the "Servicing Fee") for all obligations to be performed by the Servicer under this Agreement. For so long as LIPA is the Servicer, the Servicing Fee shall be 0.05% of the aggregate initial principal amount of the Bonds. The foregoing fee constitutes a fair and reasonable price for the obligations to be performed by the Servicer and approximates the estimated incremental cost of performing the services required by this Agreement exclusive of the expenses payable under Section 5.08. If the Servicer is not affiliated with the owner of the T&D System Assets or not performing similar services with respect to the base rates of the owner of the T&D System Assets, the Servicing Fee shall be an amount agreed upon by the Bond Issuer and the successor Servicer, provided that any Servicing Fee in excess of 0.60% of the aggregate initial principal amount of the Bonds shall be approved by the Authority and the Indenture Trustee, with notice provided to each of the Rating Agencies, and provided, further, that if the Authority fails to approve or disapprove any such Servicing Fee within 30 days following its receipt of a written request to approve the same, the Authority shall be deemed to have approved such Servicing Fee.

Section 5.08 Servicer Expenses. Except as otherwise expressly provided herein, the Bond Issuer shall pay all expenses incurred by the Servicer in connection with its activities hereunder (including any fees to and disbursements by accountants, counsel, or any other Person, any taxes or payments in lieu of taxes imposed on the Servicer (other than taxes based on the Servicer's net income) and any expenses incurred in connection with reports to Bondholders, subject to the priorities set forth in Section 8.02(e) of the Bond Indenture).

Section 5.09 Subservicing. The Servicer may at any time contract with a subservicer to perform all or any portion of its obligations as Servicer hereunder; provided, however, the Rating Agency Condition shall have been satisfied in connection therewith; and provided further that the Servicer shall remain obligated and be liable to the Bond Issuer, the Bond Trustee and the Bondholders for the servicing and administering of the Restructuring Property in accordance with the provisions hereof without diminution of such obligation and liability by virtue of the appointment of such subservicer and to the same extent and under the same terms and conditions as if the Servicer alone were servicing and administering the Restructuring Property. The fees and expenses of the subservicer shall be as agreed between the Servicer and its subservicer from time to time, and none of the Bond Issuer, the Bond Trustee or the Bondholders shall have any responsibility therefor. Any such appointment shall not constitute a Servicer resignation under Section 5.06. For purposes of this Section 5.09, the Operation Services Agreement shall be deemed to satisfy the Rating Agency Condition.

Section 5.10 No Servicer Advances. The Servicer shall not make any advances of interest on or principal of the Bonds.

Section 5.11 Remittances. No later than the second Business Day following receipt, the Servicer shall cause all payments by or on behalf of Customers, including all Charge Collections (from whatever source), to be deposited into the Allocation Account. As provided in

Section 3.03(a), the Servicer shall cause the Allocation Agent to remit the Daily Remittances due on such date to the Bond Trustee for deposit into the Collection Account. The Servicer shall transfer (i) any Indemnity Amounts and (ii) any other proceeds of other Collateral paid to or received by Servicer to the Bond Trustee for deposit in the Collection Account not later than the second Business Day following such receipt.

Section 5.12 Protection of Title. The Servicer shall execute and file such filings and cause to be executed and filed such filings, all in such manner and in such places as may be required by law fully to preserve, maintain and protect the interests of the Bond Trustee in the Restructuring Property, including all filings required under the UCC or the Statute relating to the transfer of ownership of or a security interest in the Restructuring Property by the Seller to the Bond Issuer or the security interest granted by the Bond Issuer to the Bond Trustee in the Restructuring Property. The Servicer shall deliver (or cause to be delivered) to the Bond Issuer, the Authority and the Bond Trustee file-stamped copies of, or filing receipts for, any document filed as provided above, as soon as available following such filing. The costs of any such action reasonably allocated by the Servicer to the Restructuring Property shall be payable from Charge Collections as an Ongoing Financing Cost in accordance with the Bond Indenture. The Servicer's obligations pursuant to this Section 5.12 shall survive and continue notwithstanding the fact that the payment of Ongoing Financing Costs pursuant to the Bond Indenture may be delayed (it being understood that the Servicer may be required to advance its own funds to satisfy its obligations under this Section 5.12).

Section 5.13 Tax Exempt Bonds. The Servicer covenants that it shall comply with the tax certificates to be executed and delivered by it in connection with the issuance of the Bonds and with letters of instruction, if any, delivered by bond counsel in connection with the issuance of the Bonds, as such tax certificates and letters may be amended from time to time. Notwithstanding anything else in this Agreement to the contrary, the covenants of this Section 5.13 shall survive the payment, redemption or defeasance of the Bonds and the termination of this Agreement.

Section 5.14 Compliance with Bond Issuer's Bylaws. The Servicer agrees to comply with the provisions of Article XI of the Bond Issuer's by-laws, including any amendments thereof made with the consent of the Servicer, which consent shall not be unreasonably withheld, to the extent that such provisions are applicable to its duties as agent for the Bond Issuer hereunder and, to the extent that the Servicer employs others to perform such duties in accordance with this Agreement, the Servicer will require that such others comply with such applicable provisions.

## ARTICLE VI

## DEFAULT

Section 6.01 Servicer Default. If any one of the following events (each a "Servicer Default") shall occur and be continuing:

(a) any failure by the Servicer to cause all payments by or on behalf of Customers, including all Charge Collections (from whatever source), received by the Servicer to be deposited into the Allocation Account as provided in Section 5.11 or any failure to cause the Allocation Agent to transfer to the Bond Trustee any required Daily Remittance and cause other amounts received from Collateral to be deposited to the Collections Account pursuant to Section 3.03 hereof that shall continue unremedied for a period of five (5) Business Days after written notice of such failure is received by the Servicer from the Bond Issuer or the Bond Trustee; or

(b) any failure by the Servicer duly to observe or perform in any material respect any other covenant or agreement of the Servicer set forth in this Agreement, which failure:

(i) materially and adversely affects the Restructuring Property or the rights of the Bondholders, and

(ii) continues unremedied for a period of 60 days after written notice of such failure has been given to the Servicer by the Bond Issuer, the Authority, the Allocation Agent, the Administrator or the Bond Trustee or after discovery of such failure by an officer of the Servicer; or

(c) any representation or warranty made by the Servicer in this Agreement proves to have been incorrect when made, which has a material adverse effect on the Bond Issuer or the Bondholders and which material adverse effect continues unremedied for a period of 60 days after the date on which written notice thereof has been given to the Servicer by the Bond Issuer, the Authority or the Bond Trustee or after discovery of such failure by an officer of the Servicer, as the case may be; or

(d) an Insolvency Event occurs with respect to the Servicer;

then, and in each and every case, so long as the Servicer Default shall not have been remedied, either the Bond Trustee may, or shall upon the written instruction of the Authority (acting on behalf of Customers) or the Holders of a majority of the outstanding principal amount of the Bonds, by notice then given in writing to the Servicer (and to the Bond Trustee if given by the Bondholders) (a "Termination Notice") may terminate all the rights and obligations (other than the indemnification obligations set forth in Section 5.02 hereof and the obligation under Section 6.04 to continue performing its functions as Servicer until a successor Servicer is appointed) of the Servicer under this Agreement. In addition, upon a Servicer Default, any interested person shall be entitled to apply to any court in New York for sequestration and payment of revenues arising with respect to the Restructuring Property. On or after the receipt by the Servicer of a Termination Notice, all authority and power of the Servicer under this Agreement, whether with respect to the Restructuring Property, the Charge or otherwise, shall, upon appointment of a successor Servicer pursuant to Section 6.04, without further action, pass to and be vested in such successor Servicer and, without limitation, the Bond Trustee is hereby authorized and empowered to execute and deliver, on behalf of the predecessor Servicer, as attorney-in-fact or otherwise, any and all documents and other instruments, and to do or accomplish all other acts or things necessary or appropriate to effect the purposes of such Termination Notice, whether to complete the transfer of the Restructuring Property Documentation and related documents, or otherwise. The predecessor Servicer shall cooperate with the successor Servicer, the Bond Trustee, the Bond Issuer and the Allocation Agent in effecting the termination of the responsibilities and rights of the predecessor Servicer under this Agreement, including the transfer to the successor Servicer for administration by it of all cash amounts that shall at the time be held by the predecessor Servicer for remittance, or shall thereafter be received by it with respect to the Restructuring Property or the Charge. As soon as practicable after receipt by the Servicer of such Termination Notice, the Servicer shall deliver the Restructuring Property Documentation to the successor Servicer. All reasonable costs and expenses (including attorney's fees and expenses) incurred in connection with transferring the Restructuring Property Documentation to the successor Servicer and amending this Agreement to reflect such succession as Servicer pursuant to this Section 6.01 shall be paid by the predecessor Servicer upon presentation of reasonable documentation of such costs and expenses.

Section 6.02 Notice of Servicer Default. The Servicer shall deliver to the Bond Issuer, the Authority, the Bond Trustee, the Administrator, the Allocation Agent and each Rating Agency, promptly after having obtained knowledge thereof, but in no event later than five Business Days thereafter, written notice in an Officer's Certificate of any event or circumstance which with the giving of notice or passage of time, or both, would become a Servicer Default under Section 6.01.

Section 6.03 Waiver of Past Defaults. The Bond Trustee, with the consent of the Authority and Holders of the majority of the outstanding principal amount of the Bonds, on behalf of all Bondholders, may waive in writing any default by the Servicer in the performance of its obligations hereunder and its consequences, except a default under Section 6.01(a). The Servicer shall provide notice of any such waivers to each Rating Agency, promptly after its receipt thereof from the Bond Trustee. Upon any such waiver of a past default, such default shall cease to exist, and any Servicer Default arising therefrom shall be deemed to have been remedied for every purpose of this Agreement. No such waiver shall extend to any subsequent or other default or impair any right consequent thereto.

Section 6.04 Appointment of Successor.

(a) Upon the Servicer's receipt of a Termination Notice pursuant to Section 6.01 or the Servicer's resignation in accordance with the terms of this Agreement, the predecessor Servicer shall continue to perform its functions as Servicer under this Agreement, and shall be entitled to receive the requisite portion of the Servicing Fee and reimbursement of expenses as provided herein, until a successor Servicer has assumed in writing the obligations of the Servicer hereunder as described below. In the event of the Servicer's removal or resignation hereunder and upon application of the Bond Trustee, the Authority will designate a successor Servicer. Any appointment of a successor Servicer requires the consent of the Holders of a majority of the outstanding principal amount of the Bonds, and the successor Servicer shall accept its appointment by a written assumption in form reasonably acceptable to the Bond Issuer and the Bond Trustee. If within 30 days after the delivery of the Termination Notice, a new Servicer has not been appointed and accepted such appointment, the Bond Trustee may petition the Authority or a court of competent jurisdiction to appoint a successor Servicer under this Agreement. A Person shall qualify as a successor Servicer only if (i) such Person is permitted to perform the duties of the Servicer pursuant to the Statute, the Authority Regulations, the Financing Order and this Agreement, (ii) the Rating Agency Condition has been satisfied and (iii) such Person enters into a servicing agreement with the Bond Issuer having substantially the same provisions as this Agreement.

(b) Upon appointment, the successor Servicer shall be the successor in all respects to the predecessor Servicer under this Agreement and shall be subject to all the responsibilities, duties and liabilities arising thereafter relating thereto placed on the predecessor Servicer and shall be entitled to the Servicing Fee and all the rights granted to the predecessor Servicer by the terms and provisions of this Agreement.

(c) The successor Servicer may resign only if it is prohibited from serving as such by applicable law.

Section 6.05 Cooperation with Successor. The Servicer covenants and agrees with the Bond Issuer that it will, on an ongoing basis, cooperate with the successor Servicer and provide whatever information is, and take whatever actions are, reasonably necessary to assist the successor Servicer in performing its obligations hereunder.

## ARTICLE VII

## MISCELLANEOUS PROVISIONS

Section 7.01 Amendment.

(a) This Agreement may be amended by the Servicer and the Bond Issuer, with the consent of the Bond Trustee and the satisfaction of the Rating Agency Condition. Promptly after the execution of any such amendment or consent, the Bond Issuer shall furnish written notification of the substance of such amendment or consent to each of the Rating Agencies.

Prior to the execution of any amendment to this Agreement, the Bond Issuer and the Bond Trustee shall be entitled to receive and rely upon an Opinion of Counsel stating that the execution of such amendment is authorized or permitted by this Agreement and the Opinion of Counsel referred to in Section 3.11. The Bond Issuer and the Bond Trustee may, but shall not be obligated to, enter into any such amendment which affects their own rights, duties or immunities under this Agreement or otherwise.

(b) Notwithstanding anything to the contrary in this paragraph, no amendment or modification of this Agreement shall be effective except upon satisfaction of the conditions precedent in this paragraph (b).

(i) At least fifteen days prior to the effectiveness of any such amendment or modification and after obtaining the other necessary approvals set forth in paragraph (a) above (except that the consent of the Bond Trustee may be subject to the consent of Holders if such consent is required or sought by the Bond Trustee in connection with such amendment or modification), the Servicer shall have delivered to the Authority's chief executive officer and general counsel written notification of any proposed amendment, which notification shall contain:

(A) a reference to the Financing Order;

(B) an officer's certificate stating that the proposed amendment or modification has been approved by all parties to this Agreement; and

(C) a statement identifying the person to whom the Authority or its staff is to address any response to the proposed amendment or to request additional time.

(ii) If the Authority or its staff, within fifteen days (subject to extension as provided in clause (iii) below) of receiving a notification complying with paragraph (a) above, shall have delivered to the office of the person specified in paragraph (i)(C) above a written statement that the Authority might object to the proposed amendment or modification, then such proposed amendment or modification shall not be effective unless and until the Authority subsequently delivers a written statement that it does not object to such proposed amendment or modification.

(iii) If the Authority or its staff, within fifteen days of receiving a notification complying with paragraph (a) above, shall have delivered to the office of the person specified in paragraph (i)(C) above a written statement requesting an additional amount of time not to exceed thirty days in which to consider such proposed amendment or modification, then such proposed amendment or modification shall not be effective if, within such extended period, the Authority shall have delivered to the office of the person specified in paragraph (i)(C) above a written statement as described in clause (ii) above, unless and until the Authority subsequently delivers a written statement that it does not object to such proposed amendment or modification.

(iv) If the Authority or its staff shall not have delivered written notice that the Authority might object to such proposed amendment or modification within the time periods described in clause (ii) or clause (iii) above, whichever is applicable, then the Authority shall be conclusively deemed not to have any objection to the proposed amendment or modification and such amendment or modification may subsequently become effective upon satisfaction of the other conditions specified in paragraph (a) above.

(v) Following the delivery of a notice to the Authority by the Servicer under clause (ii) above, the Servicer and the Bond Issuer shall have the right at any time to withdraw from the Authority further consideration of any proposed amendment.

(c) Notwithstanding Sections 7.01(a) and 7.01(b) or anything to the contrary in this Agreement, the Servicer may, with the prior written consent of the Authority, amend Annex 2 to this Agreement in writing with prior written notice given to the Bond Trustee, the Bond Issuer and the Rating Agencies, but without the consent of the Bond Trustee, the Bond Issuer, any Rating Agency or any Holder, solely to address changes to the Servicer's method of calculating Charge Payments as a result of changes to the Servicer's (or its subservicer's) computerized customer information system, including changes which would replace the remittances contemplated by the estimation procedures set forth in Annex 2 with remittances of Charge Collections determined to have been actually received; provided that any such amendment shall not have a material adverse effect on the Holders of the Bonds.

(d) The Servicer shall promptly provide each of the Rating Agencies and the Authority with a copy of any amendment to this Agreement.

Section 7.02 Notices. Unless otherwise specifically provided herein, all notices, directions, consents and waivers required under the terms and provisions of this Agreement shall be in English and in writing, and any such notice, direction, consent or waiver may be given by United States mail, reputable overnight courier service, facsimile transmission or electronic mail (confirmed by telephone, United States mail or reputable overnight courier service in the case of notice by facsimile transmission or electronic mail) or any other customary means of communication, and any such notice, direction, consent or waiver shall be effective when delivered or transmitted, or if mailed, five days after deposit in the United States mail with proper postage for ordinary mail prepaid:

(a) if to the Servicer, to:

LIPA
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive Officer and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(b) if to the Bond Issuer, to:

Utility Debt Securitization Authority
c/o LIPA, as Administrator
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive Officer and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(c) if to the Bond Trustee, to:

The Bank of New York Mellon
385 Rifle Camp Road – 3rd Floor
Woodland Park, NJ 07424
Attention: Frederic Belen
Telephone: (973) 247-4395
Telecopy: (732) 667-9205
Email: frederic.belen@bnymellon.com

(d) if to the Authority, to:

Long Island Power Authority
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive Officer and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfaclone@lipower.org

(e) if to Moody's, to:

Moody's Investors Service, Inc.
[25th Floor, 7 World Trade Center, 250 Greenwich Street
New York, New York 10007
Attention: ABS/RMBS Monitoring Department
Email: ServicerReports@moodys.com]

(f) if to Standard & Poor's, to:

Standard & Poor's Ratings Services
[55 Water Street
New York, NY 10041
Attention: Structured Credit Surveillance
Telephone: (212) 438-8991
E-mail: servicer-reports@standardandpoors.com
Telephone: (212) 438-8991]

(g) if to Fitch, to:

Fitch Ratings
[33 Whitehall Street
New York, New York 10004
Attention: ABS Surveillance
Email: surveillance-abs-other@fitchratings.com
Telephone: (212) 908-0500]

(h) as to each of the foregoing, at such other address as shall be designated by written notice to the other parties.

Section 7.03 Limitations on Rights of Others. The provisions of this Agreement are solely for the benefit of the Servicer, the Bond Issuer, the Authority, the Allocation Agent, the Bondholders, the Bond Trustee and the other Persons expressly referred to herein and such Persons shall have the right to enforce the relevant provisions of this Agreement, except that the Bondholders shall be entitled to enforce their rights against the Servicer under this Agreement solely through a cause of action brought for their benefit by the Bond Trustee. Nothing in this Agreement, whether express or implied, shall be construed to give to any other Person any legal or equitable right, remedy or claim in the Restructuring Property or under or in respect of this Agreement or any covenants, conditions or provisions contained herein.

Section 7.04 Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 7.05 Separate Counterparts. This Agreement may be executed by the parties hereto in separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute but one and the same instrument.

Section 7.06 Headings. The headings of the various Articles and Sections herein are for convenience of reference only and shall not define or limit any of the terms or provisions hereof.

Section 7.07 Governing Law. This Agreement shall be construed in accordance with the substantive laws of the State of New York, without giving effect to its conflict of law or other principles that would cause the application of the laws of another jurisdiction, and the obligations, rights and remedies of the parties hereunder shall be determined in accordance with such laws.

Section 7.08 Collateral Assignment to Bond Trustee. The Servicer hereby acknowledges and consents to the grant of a security interest and collateral assignment by the Bond Issuer pursuant to the Bond Indenture of all of the Bond Issuer’s rights hereunder to the Bond Trustee for the benefit of the holders of the Bonds and the Bond Trustee in and to this Agreement.

Section 7.09 Non-Petition Covenant. Notwithstanding any prior termination of this Agreement or the Bond Indenture, but subject to the right of a court of competent jurisdiction to order the sequestration and payment of revenues arising with respect to the Restructuring Property notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to any person or entity pursuant to Section 7.1(d) of the Statute, the Servicer solely in its capacity as creditor of the Bond Issuer, shall not, prior to the date which is one year and one day after the termination of the Bond Indenture with respect to the Bond Issuer, petition or otherwise invoke or cause the Bond Issuer to invoke the process of any court or governmental authority for the purpose of commencing or sustaining an involuntary case against the Bond Issuer under any federal or state bankruptcy, insolvency or similar law or appointing a receiver, liquidator, assignee, trustee, custodian, sequestrator or other similar official of the Bond Issuer or any substantial part of the property of the Bond Issuer, or, to the fullest extent permitted by law, ordering the winding up or liquidation of the affairs of the Bond Issuer.

Section 7.10 Termination. This Agreement shall terminate when all Bonds have been retired, redeemed or defeased in full.

Section 7.11 Rule 17g-5 Compliance. The Servicer agrees that any notice, report, request for satisfaction of the Rating Agency Condition, document or other information provided by the Servicer to any Rating Agency under this Agreement or any other Basic Document to which it is a party for the purposes of determining the initial credit rating of the Bonds or undertaking credit rating surveillance of the Bonds with any Rating Agency, shall be, substantially concurrently, posted by the Servicer on the 17g-5 Website.

Section 7.12 Continuing Disclosure Under Rule l5c2-12. The Servicer shall prepare and provide to the Municipal Securities Rulemaking Board, through its Electronic Municipal Market Access system ("EMMA"), in the format prescribed by the Municipal Securities Rulemaking Board, the reports, certificates and notices required under the Continuing Disclosure Agreement.

Section 7.13 Third Party Billers.

(a) If at any time in the future the State of New York takes any action to amend the Statute, or the Authority takes any action to adopt, supplement or amend Authority Regulations, in either case, to permit the billing and/or collecting of Charges by Third Parties, the Servicer, on behalf of the Bondholders, shall take such legal or administrative actions, including defending against or instituting and pursuing legal actions and appearing or testifying at hearings or similar proceedings, as may be reasonably necessary to (A) if the Servicer reasonably believes that such action could result in a downgrade of the Bonds or is otherwise contrary to the Statute or the Financing Order, block or overturn such action of the State or the Authority, as the case may be, including by asserting that such action violates the State Pledge (as defined in the Indenture); and (B) if such challenge or opposition fails, compel performance by the Authority or the State of New York, as the case may be, of their obligations and duties under the Statute and the Financing Order, as applicable, with respect to Third Parties, including but not limited to ensuring that the implementation of any such amendment, supplement, rule or regulation does not result in a downgrade in the credit ratings assigned to the Bonds and otherwise conforms with the matters referenced in Annex 1 hereto;

(i) the Servicer, on behalf of the Bondholders, will take reasonable steps to monitor on an ongoing basis proceedings in the legislature of the State of New York and at the Authority for proposed legislation, rules, regulations or other initiatives that could reasonably result in the taking by the State of New York or the Authority of any action referenced in (a) above; and

(ii) the costs of any action taken by, and the obligations of, the Servicer under this Section shall be treated in the same manner as expenses under Section 5.08.

(b) Should the laws of the State of New York be changed to permit the billing and/or collecting of Charges by Third Parties, the Servicer shall, using the same degree of care and diligence that it exercises with respect to payments owed to it for its own account, implement such procedures and policies as would be necessary to properly enforce the obligations of each Third Party to remit Charges, in accordance with the terms and provisions of the Financing Order.

IN WITNESS WHEREOF, the parties hereto have caused this Restructuring Property Servicing Agreement to be duly executed by their respective officers as of the day and year first above written.

UTILITY DEBT SECURITIZATION AUTHORITY,
as Bond Issuer

By: ___________________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

LONG ISLAND LIGHTING COMPANY,
as Servicer

By: ___________________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

# ANNEX 1

## CERTIFICATES AND ADJUSTMENTS

The Servicer agrees to comply with the following with respect to the Bond Issuer:

SECTION 1. Definitions. Capitalized terms used herein and not otherwise defined shall have the meanings set forth in Appendix A to the Restructuring Property Servicing Agreement dated as of September 29, 2022, between the Bond Issuer and LIPA, as Servicer (the "Servicing Agreement").

SECTION 2. Monthly Servicer Certificates. On or before the 13th Business Day of each calendar month commencing with November 2022, the Servicer will deliver to the Allocation Agent, the Bond Issuer, the Authority, the Bond Trustee and each Rating Agency a monthly certificate in substantially the form of Exhibit A hereto (the "Monthly Servicer Certificate") stating the amount of the total charges received from Customers deposited into the Allocation Account during the preceding calendar month, the estimated amount of Charge Collections transferred to the Collection Account during the preceding calendar month, the amount of any transfers or reductions in respect of Excess Remittances or the Remittance Shortfalls occurring during the preceding calendar month, and the amount of any transfers or reductions in respect of Excess Remittances or Remittance Shortfalls required to occur on any Remittance Date during the current month pursuant to Section 3.03(b) of the Servicing Agreement.

SECTION 3. Semiannual Servicer Certificates. At least one Business Day before each Payment Date, the Servicer shall provide to the Bond Issuer, the Bond Trustee, each Rating Agency and the Authority, a certificate in substantially the form of Exhibit B hereto (the "Semiannual Servicer Certificate") indicating:

1. the amount to be paid to the Bondholders of each Tranche in respect of principal on such Payment Date in accordance with Section 8.02(e) of the Bond Indenture;

2. the amount to be paid to the Bondholders of each Tranche in respect of interest on such Payment Date in accordance with Section 8.02(e) of the Bond Indenture;

3. the Projected Bond Balance and the Bond Balance for each Tranche as of that Payment Date (after giving effect to the payments on such Payment Date);

4. the amount on deposit in the Reserve Subaccount as of that Payment Date (after giving effect to the transfers to be made from or into the Reserve Subaccount on such Payment Date);

5. the amount, if any, on deposit in the Excess Funds Subaccount as of that Payment Date (after giving effect to the transfers to be made from or into the Excess Funds Subaccount on such Payment Date);

6. the amounts paid to the Bond Trustee since the preceding Payment Date pursuant to Section 8.02(e) of the Bond Indenture;

7. the amounts paid to the Servicer since the preceding Payment Date pursuant to Section 8.02(e) of the Bond Indenture; and

8. the amount of any other transfers and payments to be made on such Payment Date pursuant to Sections 8.02(e) of the Bond Indenture.

SECTION 4. Annual Certificates. The Servicer shall provide the Certificate of Compliance required by Section 3.06 of the Servicing Agreement in substantially the form of Exhibit C hereto.

SECTION 5. True-Up Adjustments.

(a) The Servicer will make adjustments to the Charge at least annually, beginning November 15, 2022 and continuing until the last Scheduled Maturity Date of the Bonds (or any series of Bonds). The Annual True-up (defined below) will be performed on a mandatory basis; the Mid-year Review (defined below) will also be performed on a mandatory basis and the Mandatory Mid-year True-up (defined below) will only be required to be performed if the Servicer projects under collections to be experienced up to the end of the next succeeding Mid-year Calculation Period ( as defined below), provided that the Servicer may elect to perform a Voluntary Mid-year True-up (defined below) in any year as provided below. For each Annual True-up, Mandatory Mid-year True-up or Voluntary True-up adjustment (each a “True-Up Adjustment”), the Servicer will file with the Securitization Authority a notice of adjustment to the Charge approximately 30 days prior to the effective date of such adjustment.

(b) Annually, the Servicer will file a notice of adjustment (the “Annual True-up”) (i) to correct for any over-collections or under-collections to date and anticipated to be experienced to the end of the then current Annual Calculation Period, as defined below (the next succeeding December 15), and (ii) to ensure that the Charge during the period commencing on each November 15 and ending on the following November 14 is adequate to pay timely principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule and to make timely payment on all other Ongoing Financing Costs due during the period beginning on the next December 16 and ending on the following December 15 (each such period, an “Annual Calculation Period”). Before April 15, 2023 and each April 15 thereafter, the Servicer will perform a mid-year review (each a “Mid-year Review”) to ensure that the expected collections of the Charge are adequate to pay timely principal and interest on the Bonds when due and to make timely payment on all other Ongoing Financing Costs to the end of the then current Annual Calculation Period. If the Mid-year Review results in a projection that the Charge Collections will be insufficient to make such payments, the Servicer must file a notice of adjustment (the “Mandatory Mid-Year True-Up Adjustment”) to ensure that Charge during the period beginning on May 15 and ending on the following May 14 is adequate to pay timely principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule and to make timely payment on all other Ongoing Financing Costs due during the period beginning on the next June 16 and ending on the following June 15 (each such period a “Mid-year Calculation Period”) . If it is determined that a Mandatory Mid-year True-up is not required, the Servicer may nevertheless voluntarily elect to file a notice of adjustment (i) to correct for any over-collections to date and anticipated to be experienced up to the end of the then current Mid-year Calculation Period and (ii) to ensure that the Charge during the period beginning on May 15 and ending on the following

May 14 is adequate to pay timely principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule and to make timely payment on all other Ongoing Financing Costs due during the next Mid-year Calculation Period (a "Voluntary Mid-year True-up"). Any such notice of adjustment for a Mandatory Mid-year True-up or a Voluntary Mid-year True-up shall be filed no later than April 15 of such year, any such adjustment to become effective on May 15 of such year of such year. Additionally, the Servicer may file at any time an additional optional notice of adjustment to ensure that the expected collections of the Charge are adequate to pay timely principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule and to make timely payment on all other Ongoing Financing Costs (an "Optional True-up").

(c) Following the last Scheduled Maturity Date of the Bonds (or any series of Bonds), if any such Bonds remain outstanding after such Scheduled Maturity Date, the Servicer will file quarterly notices of adjustments to the Charge to ensure that the Charge Collections will be sufficient to pay timely interest and principal in full on the Bonds (or any series of Bonds) that remain outstanding after such Scheduled Maturity Date and to make timely payment on all other Ongoing Financing Costs on the next payment date.

(d) All adjustments will be designed to cause (i) the outstanding principal balance of the Bonds (or any series of Bonds) to be equal to the scheduled balance (based on the Expected Amortization Schedule) with respect to such Bonds (or any series of Bonds); (ii) the amount in the Reserve Subaccount to be equal to the Required Reserve Level; (iii) with respect to the Annual True-up only, any amount in the Excess Funds Subaccount to be targeted to be zero by the Payment Date immediately preceding the effective date of the next Annual True-up or by the Final Maturity Date on the Bonds, if the next Payment Date is the Final Maturity Date of all of the Bonds (or any series of Bonds); and (iv) with respect to a Voluntary Mid-year True-up only, any amount in the Excess Funds Subaccount to be targeted to be zero by the Payment Date immediately following the effective date of the next Mid-year Review or by the Final Maturity Date on the Bonds, if the next Payment Date is the Final Maturity Date of all of the Bonds (or any series of Bonds).

(e) For the period prior to the last Scheduled Maturity Date of the Bonds (or any series of Bonds), the Servicer will calculate the adjustments for the Annual True-up to be effective as of each November 15 in the following manner:

(1) Calculate under-collections or over-collections of Charge Collections from all prior Collection Periods on a cumulative basis by subtracting (a) the sum of (i) principal and interest paid and scheduled to be paid on the Bonds through the end of the current Annual Calculation Period and (ii) all Ongoing Financing Costs paid and expected to be payable through the end of the current Annual Calculation Period from (b) the Charge Collections to date and amounts released from the Reserve Subaccount that are in excess of the Required Debt Service Reserve Level as well as all Charge Collections projected to be received prior to the end of the current Annual Calculation Period.

(2) Calculate the amount of Charges that must be billed through November 14 of the next succeeding calendar year such that the Charges are sufficient (a) to pay timely

principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule during the Annual Calculation Period ending on December 15 of the next succeeding calendar year, and (b) to make timely payment on all other Ongoing Financing Costs, given (i) projected energy consumption, (ii) projected uncollectibles, and (iii) projected lags in collection of billed Charges through at least the end of such next succeeding Annual Calculation Period.

(3) Sum amounts in steps (1) and (2) above.

(4) Divide the resulting amount in step (3) above by the forecasted energy billing units for the twelve month period ending on such November 14 of the next succeeding calendar year to determine the Charge to be in effect until the effective date of the next True-up Adjustment.

(f) For the period prior to the last Scheduled Maturity Date of the Bonds (or any series of Bonds), the Servicer will perform the Mid-year Review before April 15 following the effective date of each Annual True-up, calculated in the following manner:

(1) Determine the Charge Collections from the applicable Annual Calculation Period, taking into account actual collections and collections projected to be received prior to the end of the current Annual Calculation Period.

(2) Calculate the amount of Charges that must be billed prior to the effective date of the next Annual True-up such that the Charges are sufficient (a) to pay timely principal and interest on the Bonds when due during the current Annual Calculation Period pursuant to the Expected Amortization Schedule and (b) to make timely payment on all other Ongoing Financing Costs during such Annual Calculation Period, given (i) projected energy consumption, (ii) projected uncollectibles, and (iii) projected lags in collection of billed Charges through at least the end of such Annual Calculation Period.

(3) If the amount resulting from the calculation in step (2) is greater than step (1), the Servicer will institute a Mandatory Mid-year True-up in the manner described below.

(g) For the period prior to the last Scheduled Maturity Date of the Bonds (or any series of Bonds), the Servicer will calculate the adjustments for the Mandatory Mid-year True-up in the following manner:

(1) Calculate the amount of Charges that must be billed prior to May 15 of the next succeeding calendar year such that the Charges are sufficient (a) to pay timely principal and interest on the Bonds when due pursuant to the Expected Amortization Schedule during the Mid-year Calculation Period ending on June 15 of the next succeeding calendar year and (b) to make timely payment on all other Ongoing Financing Costs during such Mid-year Calculation Period, given (i) projected energy consumption, (ii) projected uncollectibles, and (iii) projected lags in collection of billed Charges through at least end of such Mid-year Calculation Period.

(2) Divide the amount in step (1) above by the forecasted energy billing units to determine the Charge to be in effect until May 15 of the next succeeding calendar year.

(h) For the period prior to the last Scheduled Maturity Date of the Bonds (or any series of Bonds) if the Servicer elects to implement a Voluntary Mid-year True-up, the Servicer shall calculate the adjustments for the Voluntary Mid-year True-up in the same manner described in clause (e) above with respect to an Annual True-up provided that references in such clause (e) to an Annual Calculation Period shall be deemed to refer to a Mid-year Calculation Period and references in clause (e)(4) to the effective date of the next True-up Adjustment shall be deemed to refer to May 15 of the next succeeding calendar year.

(i) Each Adjustment Notice shall include a description of the adjustment calculation, the mathematical formulas used for such calculations and the amounts of each variable used in such formulas.

(j) If necessary to provide for timely payment of scheduled principal of and interest on the Bonds and the payment and recovery of other Ongoing Financing Costs, the Servicer shall prepare and file an Adjustment Notice with the Authority for each Optional True-up. Such filings shall be made at least 30 days prior to the proposed effective date of the proposed adjustments.

(k) Notices.

(1) Notices to the Bond Issuer, Bond Trustee and Rating Agencies. Whenever the Servicer files an Adjustment Notice with the Authority, the Servicer shall send a copy of such filing to the Bond Issuer, the Bond Trustee, the Administrator, the Allocation Agent and the Rating Agencies concurrently therewith, post a copy of such filing on the 17g-5 Website and within thirty (30) days of such filing, to the Electronic Municipal Market Access system maintained by the Municipal Securities Rulemaking Board. If any True-Up Adjustment described in any such Adjustment Notice filing does not become effective on the applicable date for any reason, the Servicer shall notify the Bond Issuer, the Allocation Agent, the Bond Trustee and the Rating Agencies by the end of the second Business Day after such applicable date.

(2) Notices to Customers.

(A) After each revised Charge has gone into effect pursuant to a True-Up Adjustment, the Servicer shall, to the extent and in the manner and time frame required by applicable Authority Regulations, if any, cause to be prepared and delivered to customers any required notices announcing such revised Charges.

(B) The Servicer shall comply with the requirements of the LIPA Reform Act and the Financing Order with respect to the identification of the Charges on Bills. In addition, at least once each year, the Servicer shall (to the extent that it does not separately identify the Charges as being owned by the Bond Issuer in the Bills regularly sent to Customers) cause to be prepared and delivered to such Customers a notice stating, in effect, that the Restructuring Property and the Charges are owned solely by the Bond Issuer and not the Servicer. Such notice shall be included either as an insert to or in the text of the Bills delivered to such Customers or shall be delivered to Customers by electronic means or such other means as the Servicer may from time to time use to communicate with its own Customers.

# ANNEX 2

## PROCEDURES

The Servicer agrees to comply with the following servicing procedures:

SECTION 1. Definitions.

(a) Capitalized terms used herein and not otherwise defined shall have the meanings set forth in the Restructuring Property Servicing Agreement dated as of September 29, 2022, between the Bond Issuer and LIPA, as Servicer (the "Servicing Agreement").

(b) Whenever used in this Annex 2, the following words and phrases shall have the following meanings:

"Applicable MDMA" means, with respect to each Customer, the meter data management agent or other person providing meter reading services for that Customer's account.

"Applicable Third Party" means, with respect to each Customer, the Third Party, if any, providing billing or metering services to that Customer.

"Billed Charges" means the amounts billed to Customers pursuant to the Charge, whether billed directly to such Customers by the Servicer or indirectly through a Third Party pursuant to Consolidated Third Party Billing.

"Bills" means each of the regular monthly bills, the summary bills, the initial bills and the Closing Bills issued to Customers or Third Parties by LIPA.

"Budget Payment Plan" means a levelized payment plan offered by LIPA, which, if elected by a Customer, provides for level monthly Bill charges to such Customer. For residential Customers, this charge is calculated by calculating actual electricity usage for the previous 12 months, multiplying that usage by the applicable rates and non-usage sensitive charges and dividing this amount by twelve. The number which results from this calculation is charged to the residential Customer each month. The procedure is similar for small industrial and commercial Customers.

"Charge Effective Date" means the date on which the initial Charge goes into effect pursuant to the Financing Order.

"Closing Bill" means the final bill issued to a Customer at the time service is terminated.

"Consolidated Third Party Billing" means the billing option available to Customers served by a Third Party pursuant to which such Third Party will be responsible for billing and collecting all charges to Customers electing such billing option, including the Charge, and will become obligated to the Servicer for the Billed Charges, all in accordance with applicable Authority Regulations and the Financing Order.

"Days Sales Outstanding" means the average number of days that monthly bills to Customers for electric transmission and distribution services in the Service Area (or, following the authorization of Third Parties to bill and collect Customers for electric transmission and distribution services in the Service Area, monthly bills to Third Parties) remain outstanding during the calendar year immediately preceding the calculation of projected lags in collection of billed Charges pursuant to Annex 2 of the Servicing Agreement. The initial Days Sales Outstanding shall be 39 days until updated pursuant to Annex 2 of the Servicing Agreement.

"Servicer Policies and Practices" means, with respect to the Servicer's duties under this Annex 2, the policies and practices applicable to such duties that the Servicer (or its sub-servicer) follows with respect to the T&D Rates.

SECTION 2. Data Acquisition.

(a) Installation and Maintenance of Meters. Except to the extent that a Third Party is responsible for such services, the Servicer shall use commercially reasonable efforts to cause to be installed, replaced and maintained meters in such places and in such condition as will enable the Servicer to obtain usage measurements for each Customer approximately every 30 days or as provided in the applicable tariff.

(b) Meter Reading. At least once each Billing Period, the Servicer shall obtain usage measurements from the Applicable MDMA for each Customer; provided, however, that the Servicer may determine any Customer's usage on the basis of estimates in accordance with applicable Authority Regulations.

(c) Cost of Metering. The Bond Issuer shall not be obligated to pay any costs associated with the metering duties set forth in this Section 2, including, but not limited to, the costs of installing, replacing and maintaining meters, nor shall the Bond Issuer be entitled to any credit against the Servicing Fee for any cost savings realized by the Servicer or any Third Party as a result of new metering and/or billing technologies.

SECTION 3. Usage and Bill Calculation.

The Servicer shall obtain a calculation of each Customer's usage (which may be based on data obtained from such Customer's meter read or on usage estimates determined in accordance with applicable Authority Regulations) at least once each Billing Period and shall determine therefrom the amount of the Charge to be included on such Customer's Bill pursuant to the Financing Order and Authority Regulations.

SECTION 4. Billing.

The Servicer shall implement the Charge as of the Charge Effective Date and shall thereafter bill each Customer or the Applicable Third Party for the respective Customer's outstanding current and past due charges relating to the Charge, accruing until all payments of principal and interest on the Bonds and all other Ongoing Financing Costs have been paid in accordance with the Indenture, all in accordance with the following:

(a) Frequency of Bills; Billing Practices. In accordance with the Servicer's then-existing Servicer Policies and Practices, as such Servicer Policies and Practices may be modified from time to time, the Servicer shall generate and issue a Bill to each Customer, or, in the case of a Customer who has elected Consolidated Third Party Billing, to an Applicable Third Party, for such Customer's respective Charge as a general practice once approximately every 30 days or such other time period as allowed by the Authority, at the same time, with the same frequency and on the same Bill as that containing the Servicer's T&D Rates to such Customer or Third Party, as the case may be. In the event that the Servicer makes any material modification to these practices, it shall notify the Bond Issuer, the Bond Trustee, the Allocation Agent and the Rating Agencies as soon as practicable, and in no event later than 60 Business Days after such modification goes into effect; provided, however, that the Servicer may not make any modification that will materially adversely affect the Bondholders.

(b) Format.

(i) Pursuant to the Financing Order, each Bill will identify the Charges included in such Bill by means of a footnote or other description of the amount of the Charge or the Charge per kWh and a statement to the effect that the Charges belong to the Bond Issuer.

(ii) In the case of each Customer that has elected Consolidated Third Party Billing, the Servicer shall deliver to the Applicable Third Party itemized charges for such Customer including the amount of such Customer's Charge and text identifying the Bond Issuer as the owner of such Charge.

(iii) The Servicer shall conform to such requirements in respect of the format, structure and text of Bills delivered to Customers and Third Parties as applicable Authority Regulations shall from time to time prescribe. To the extent that Bill format, structure and text are not prescribed by the Statute, other applicable law or Authority Regulations, the Servicer shall, subject to clauses (i) and (ii) above, determine the format, structure and text of all Bills in accordance with its reasonable business judgment, the Servicer Policies and Practices and prevailing industry standards.

(c) Delivery.

The Servicer shall deliver all Bills to Customers:

(i) by United States mail in such class or classes as are consistent with the Servicer Policies and Practices followed by the Servicer with respect to the T&D Rates; or

(ii) by any other means, whether electronic or otherwise, that the Servicer may from time to time use to bill the T&D Rates to Customers. In the case of Customers that have elected Consolidated Third Party Billing, the Servicer shall deliver all Bills to the applicable Third Parties by such means as are prescribed by applicable Authority Regulations, or if not prescribed by applicable Authority Regulations, by such means as are mutually agreed upon by the Servicer and the applicable Third Party and are consistent with Authority Regulations. The Servicer or a Third Party, as applicable, shall pay from its own funds all costs of issuance and delivery of all Bills, including but not limited to printing and postage costs as the same may increase or decrease from time to time.

SECTION 5. Customer Service Functions.

The Servicer shall handle all Customer inquiries and other Customer service matters according to the same procedures it uses to service Customers with respect to the T&D Rates.

SECTION 6. Collections; Payment Processing; Remittances.

(a) Collection Efforts, Policies, Procedures.

(i) The Servicer shall use reasonable efforts to collect all Billed Charges from Customers and Third Parties as and when the same become due and shall follow such collection procedures as it follows with respect to the T&D Rates, including, as follows:

(A) The Servicer shall prepare and deliver overdue notices to Customers and Third Parties in accordance with applicable Authority Regulations and the Servicer Policies and Practices.

(B) The Servicer shall apply late payment charges to outstanding Customer and Third Party balances in accordance with applicable Authority Regulations. All late payment charges and interest collected shall be payable to and retained by the Servicer as a component of its compensation under the Servicing Agreement, and the Bond Issuer shall not have any right to share in the same.

(C) The Servicer shall deliver verbal and written final call notices in accordance with applicable Authority Regulations and Servicer Policies and Practices.

(D) The Servicer shall adhere and carry out disconnection policies in accordance with the Statute, other applicable law and Authority Regulations and Servicer Policies and Practices.

(E) The Servicer may employ the assistance of collections agents in accordance with applicable Authority Regulations and Servicer Policies and Practices.

(F) The Servicer shall apply Customer and Third Party deposits, Customers' letters of credit and Customer posted surety bonds to the payment of delinquent accounts in accordance with applicable Authority Regulations and Servicer Policies and Practices and according to the priorities set forth in Section 6(b)(ii), (iii) and (iv) of this Annex 2.

(G) The Servicer shall promptly take all necessary action in accordance with applicable Authority Regulations to terminate billing of Charges by Third Parties whose payments are delinquent and to collect the Billed Charges directly from the applicable Customers.

(ii) The Servicer shall not waive any late payment charge or any other fee or charge relating to delinquent payments, if any, or waive, vary or modify any terms of payment of any amounts payable by a Customer, in each case unless such waiver or action:

(A) would be in accordance with the Servicer's customary practices or those of any successor Servicer with respect to comparable assets that it services for itself and for others;

(B) would not materially adversely affect the rights of the Bondholders; and

(C) would comply with applicable law; provided, however, that notwithstanding anything in the Servicing Agreement or this Annex 2 to the contrary, the Servicer is authorized to write off any Billed Charges in accordance with its Servicer Policies and Practices that remain outstanding for 120-150 days.

(iii) The Servicer shall accept payment from Customers in respect of Billed Charges in such forms, by such methods and at such times and places as it accepts payment of the T&D Rates. The Servicer shall accept payment from Third Parties in respect of Billed Charges in such forms, by such methods and at such times and places as the Servicer and each Third Party shall mutually agree in accordance with applicable Authority Regulations.

(b) Payment Processing; Allocation; Priority of Payments.

(i) The Servicer shall post all payments received to Customer accounts as promptly as practicable, and, in any event, substantially all payments shall be posted no later than two Business Days after receipt.

(ii) Subject to clause (iii) below, the Servicer shall apply payments received to each Customer's or Third Party's account in proportion to the charges contained on the outstanding Bill to such Customer or Third Party.

(iii) Any amounts collected by the Servicer that represent partial payments of the total Bill to a Customer or Third Party shall be allocated in accordance with the priorities set forth in Section 3.02(b) of the Servicing Agreement.

(iv) The Servicer shall cause all over-payments to be deposited into the Allocation Account and shall allocate such funds in accordance with clauses (ii) and (iii).

(v) For Customers on a Budget Payment Plan, the Servicer shall treat Charge Collections received from such Customers as if such Customers had been billed for the Charge in the absence of the Budget Payment Plan. Partial payment of a Budget Payment Plan payment shall be allocated according to clause (iii) above, and overpayment of a Budget Payment Plan payment shall be allocated according to clause (iv) above.

(c) Accounts; Records.

(i) The Servicer shall maintain accounts and records as to the Restructuring Property accurately and in accordance with its standard accounting procedures and in sufficient detail to permit reconciliation between payments or recoveries with respect to the Restructuring Property and the amounts from time to time remitted to the Collection Account in respect of the Restructuring Property.

(ii) The Servicer shall maintain accounts and records as to Third Parties performing Consolidated Third Party Billing for Customers accurately and in accordance with its standard accounting procedures and in sufficient detail to permit reconciliation between payments or recoveries with respect to the Restructuring Property and amounts owed by such Customers in respect of the Charge.

(d) Calculation of Daily Remittances, Excess Remittances and Remittance Shortfalls.

1. For purposes of calculating the Daily Remittance, (i) all Billed Charges shall be estimated to be collected the same number of days after billing as is equal to the Days Sales Outstanding then in effect (or on the next Business Day) and (ii) the Servicer will, on each Business Day, cause the Allocation Agent to remit to the Collection Account an amount equal to the product of the Billed Charges estimated to be collected on such Business Day multiplied by one hundred percent less the percentage of projected uncollectibles used by the Servicer to calculate the most recent adjustment pursuant to Annex 1 of the Servicing Agreement. Such product shall constitute the amount of Estimated Charge Collections for such Business Day.

2. Pursuant to Section 3.03(c) of the Servicing Agreement, within fifteen days prior to the date on which an Adjustment Notice is filed with the Authority, the Servicer shall calculate and report in the next succeeding Monthly Servicer's Certificate the amount of Actual Charge Collections for all completed Collection Periods during the Reconciliation Period as compared to the Estimated Charge Collections remitted to the Collection Account in respect of such Reconciliation Period and any Excess Remittance or Remittance Shortfall. Actual Charge Collections will be calculated using actual data, including actual electricity consumption, actual uncollectibles and actual lags in collection for the Reconciliation Period. If Third Parties are authorized to bill, collect and remit Charges, the Servicer shall be allowed to use the reimbursement of any Excess Remittance to reimburse any Third Parties for the excess of their remittances over actual Charge Payments received by such Third Parties in accordance with the terms of Authority Regulations.

3. On or before the times specified in Annex 1 to the Servicing Agreement, the Servicer shall, in a timely manner so as to perform all required calculations under Annex 1 to the Servicing Agreement for the True-up Adjustments, update the Days Sales Outstanding, the projected lags in collection of billed Charges and the projected uncollectibles in order to be able to calculate the next True-Up Adjustment and to calculate any change in the Daily Remittances for the next Reconciliation Period.

4. All calculations of collections, each update of the Days Sales Outstanding, the projected lags in collection of billed Charges, the projected uncollectibles and any changes in procedures used to calculate the Estimated Charge Payments pursuant to this Section 6(d) of this Annex 2 shall be made in good faith, and

in the case of any update pursuant to clause 6(d)(2) above, in a manner reasonably intended to provide estimates and calculations that are at least as accurate as those that were provided on the Closing Date utilizing the initial procedures.

(e) Remittances.

1. The Servicer shall make or cause payments to the Collection Account or the Allocation Account in accordance with Sections 3.03 and 5.11 and this Annex 2 of the Servicing Agreement.

2. In the event of any change of account or change of institution affecting the remittances, the Bond Issuer shall provide written notice thereof to the Servicer by the earlier of:

(A) five Business Days from the effective date of such change, or

(B) five Business Days prior to the next applicable Remittance Date.

# EXHIBIT A

## FORM OF MONTHLY SERVICER CERTIFICATE

Utility Debt Securitization Authority Restructuring Bonds

Servicer: Long Island Lighting Company

Pursuant to the Restructuring Property Servicing Agreement, dated as of September 29, 2022 (the "Servicing Agreement"), between the LONG ISLAND LIGHTING COMPANY, as Servicer, and the UTILITY DEBT SECURITIZATION AUTHORITY, the undersigned does hereby certify as follows:

1. For period beginning ______and ended _____ (the "Certificate Period"):

| | |
|---|---|
| Deposits into Allocation Account | $ |
| Actual Charge Collections deposited into Allocation Account | $ |
| Estimated Charge Collections remitted to Collection Account | $ |
| Excess Remittance deducted during period | $ |
| Remittance Shortfall instructed to be transferred to the Collection Account | $ |
| Excess Remittance instructed to be deducted from future Daily Remittances | $ |
| Excess Remittance to be paid or transferred from the Collection Account or the Excess Funds Subaccount | $ |

2. To the best of the undersigned's knowledge, the Servicer has fulfilled all of its obligations in all material respects under Section 3.03(a) of the Servicing Agreement throughout the Certificate Period [, except _____].

In WITNESS HEREOF, the undersigned has duly executed and delivered this Monthly Servicer Certificate the day of

[Name of Entity]

By ___________________
Name:
Title:

# EXHIBIT B

## FORM OF SEMIANNUAL SERVICER CERTIFICATE

Utility Debt Securitization Authority Restructuring Bonds

Pursuant to the Restructuring Property Servicing Agreement, dated as of September 29, 2022, (the "Servicing Agreement"), between LONG ISLAND LIGHTING COMPANY, as Servicer, and UTILITY DEBT SECURITIZATION AUTHORITY, the undersigned does hereby certify, for the ___, 20_ Payment Date (the "Current Payment Date"), as follows:

Capitalized terms used herein have their respective meanings as set forth in the Servicing Agreement, or if not defined in the Servicing Agreement, as set forth in the Bond Indenture. References herein to certain sections and subsections are references to the respective sections of the Servicing Agreement or the Bond Indenture, as the context indicates.

Collection Period: [____________] through [__________]

Payment Date: [____________]

Date of Certificate: [____________]

Cut-Off Date (not more than ten days prior to the date hereof): [____________]:

(a) Available Amounts on Deposit in Collection Account (including Excess Funds Subaccount) as of Cut-Off Date [date nor more than ten days prior to date of this certificate]: $

(b) Actual or Estimated Remittances from the date in (a) above through the Servicer Business Day preceding Current Payment Date: $

(c) Total Amounts Available to Trustee for Payment of Bonds and Other Ongoing Financing Costs: $

(d) Allocation of Available Amounts as of Current Payment Date allocable to payment of principal and interest on Bonds on Current Payment Date:

Principal

Aggregate

**Total**

Interest

Aggregate

**Total**

(e) Outstanding Amount of Bonds prior to, and after giving effect to the payment on the Current Payment Date and the difference, if any, between the Outstanding Amount specified in the Expected Amortization Schedule (after giving effect to payments to be made on such Payment Date set forth above) and the Principal Balance to be Outstanding (following payment on Current Payment Date):

Principal Balance Outstanding (as of the date of this certification):

**Total**

Principal Balance to be Outstanding (following payment on Current Payment Date):

**Total**

(f) Difference between (e) above and Outstanding Amount specified in the Expected Amortization Schedule:

**Total**

(g) All other transfers to be made on the Current Payment Date, including amounts to be paid to the Bond Trustee and to the Servicer pursuant to Section 8.02(e) of the Bond Indenture:

Ongoing Financing Costs:

Bond Trustee Fees and Expenses:
Servicer Fees and Expenses:
Administration Fees and Expenses:
Rating Agency Fees:
Accounting Fees:

Funding of Reserve Subaccount (to required amount):
Total:

(h) Estimated amounts on deposit in the Reserve Subaccount and Excess Funds Subaccount after giving effect to the foregoing payments:

Reserve Subaccount

Total:

Excess Funds Subaccount

Total:

In witness hereof, the undersigned has duly executed and delivered this Semiannual Servicer Certificate this _day of __, 20_.

[Name of Entity]

By ____________________
Name:
Title:

# EXHIBIT C

## CERTIFICATE OF COMPLIANCE

Utility Debt Securitization Authority Restructuring Bonds

Pursuant to the Restructuring Property Servicing Agreement, dated as of September 29, 2022 (the "Servicing Agreement"), between LONG ISLAND LIGHTING COMPANY, as Servicer, and UTILITY DEBT SECURITIZATION AUTHORITY, the undersigned does hereby certify, for the ______, 20_ Payment Date (the "Current Payment Date"), as follows:

The undersigned hereby certifies that he/she is the duly elected and acting [___] of [___] and further that:

1. A review of the activities of the Servicer and any of its subcontractors and of its performance under the Servicing Agreement during the twelve months ended [___], [___] has been made under the supervision of the undersigned pursuant to Section 3.06 of the Servicing Agreement; and

2. To the best of the undersigned's knowledge, based on such review, the Servicer has fulfilled all of its obligations in all material respects under the Servicing Agreement throughout the twelve months ended [___], [___], except _____.

Executed as of this _____ day of _____, 2022

______________________________
Name:
Title:

# EXHIBIT D

## ADJUSTMENT NOTICE

Pursuant to the Restructuring Cost Financing Order No. 6 of the Long Island Power Authority ("Authority") adopted May 18, 2022 (the "Financing Order") and the Restructuring Property Servicing Agreement, dated as of September 29, 2022 (the "Servicing Agreement"), between the LONG ISLAND LIGHTING COMPANY, as Servicer, and the UTILITY DEBT SECURITIZATION AUTHORITY, the undersigned does hereby provides notice of an adjustment to the Charge to take effect on the Adjustment Date specified below.

Adjustment Date:

Adjusted Charge:

The adjusted Charge was calculated as follows:

Executed as of this _________ day of _____________, 2022.

By:_________________________
Name:
Title:

## SCHEDULE

# EXPECTED AMORTIZATION SCHEDULE

| | Principal Balance | Principal (A) | Interest (A) | Debt Service (A) |
|---|---|---|---|---|
| 9/29/2022 | $935,655,000 | $0 | $0 | $0 |
| 12/15/2022 | 935,655,000 | 0 | 9,840,140 | 9,840,140 |
| 6/15/2023 | 935,655,000 | 16,315,000 | 23,305,594 | 39,620,594 |
| 12/15/2023 | 919,340,000 | 16,685,000 | 22,927,711 | 39,612,711 |
| 6/15/2024 | 902,655,000 | 6,055,000 | 22,541,230 | 28,596,230 |
| 12/15/2024 | 896,600,000 | 6,205,000 | 22,389,855 | 28,594,855 |
| 6/15/2025 | 890,395,000 | 12,010,000 | 22,234,730 | 34,244,730 |
| 12/15/2025 | 878,385,000 | 12,300,000 | 21,934,480 | 34,234,480 |
| 6/15/2026 | 866,085,000 | 49,330,000 | 21,626,980 | 70,956,980 |
| 12/15/2026 | 816,755,000 | 50,560,000 | 20,393,730 | 70,953,730 |
| 6/15/2027 | 766,195,000 | 67,560,000 | 19,129,730 | 86,689,730 |
| 12/15/2027 | 698,635,000 | 69,250,000 | 17,440,730 | 86,690,730 |
| 6/15/2028 | 629,385,000 | 38,975,000 | 15,709,480 | 54,684,480 |
| 12/15/2028 | 590,410,000 | 39,950,000 | 14,735,105 | 54,685,105 |
| 6/15/2029 | 550,460,000 | 55,450,000 | 13,736,355 | 69,186,355 |
| 12/15/2029 | 495,010,000 | 56,820,000 | 12,360,098 | 69,180,098 |
| 6/15/2030 | 438,190,000 | 30,740,000 | 10,949,817 | 41,689,817 |
| 12/15/2030 | 407,450,000 | 31,500,000 | 10,181,317 | 41,681,317 |
| 6/15/2031 | 375,950,000 | 17,090,000 | 9,393,817 | 26,483,817 |
| 12/15/2031 | 358,860,000 | 17,515,000 | 8,966,567 | 26,481,567 |
| 6/15/2032 | 341,345,000 | 17,765,000 | 8,528,692 | 26,293,692 |
| 12/15/2032 | 323,580,000 | 18,205,000 | 8,084,567 | 26,289,567 |
| 6/15/2033 | 305,375,000 | 13,130,000 | 7,629,442 | 20,759,442 |
| 12/15/2033 | 292,245,000 | 13,460,000 | 7,301,192 | 20,761,192 |
| 6/15/2034 | 278,785,000 | 2,710,000 | 6,964,692 | 9,674,692 |
| 12/15/2034 | 276,075,000 | 2,780,000 | 6,896,942 | 9,676,942 |
| 6/15/2035 | 273,295,000 | 445,000 | 6,827,442 | 7,272,442 |
| 12/15/2035 | 272,850,000 | 455,000 | 6,816,317 | 7,271,317 |
| 6/15/2036 | 272,395,000 | 46,385,000 | 6,804,942 | 53,189,942 |
| 12/15/2036 | 226,010,000 | 47,545,000 | 5,645,317 | 53,190,317 |
| 6/15/2037 | 178,465,000 | 41,325,000 | 4,456,692 | 45,781,692 |
| 12/15/2037 | 137,140,000 | 42,360,000 | 3,426,003 | 45,786,003 |
| 6/15/2038 | 94,780,000 | 2,630,000 | 2,369,500 | 4,999,500 |
| 12/15/2038 | 92,150,000 | 2,700,000 | 2,303,750 | 5,003,750 |
| 6/15/2039 | 89,450,000 | 2,765,000 | 2,236,250 | 5,001,250 |
| 12/15/2039 | 86,685,000 | 2,835,000 | 2,167,125 | 5,002,125 |
| 6/15/2040 | 83,850,000 | 2,905,000 | 2,096,250 | 5,001,250 |
| 12/15/2040 | 80,945,000 | 2,980,000 | 2,023,625 | 5,003,625 |
| 6/15/2041 | 77,965,000 | 3,050,000 | 1,949,125 | 4,999,125 |
| 12/15/2041 | 74,915,000 | 3,130,000 | 1,872,875 | 5,002,875 |
| 6/15/2042 | 71,785,000 | 3,205,000 | 1,794,625 | 4,999,625 |
| 12/15/2042 | 68,580,000 | 3,285,000 | 1,714,500 | 4,999,500 |

| | | | | |
|---|---|---|---|---|
| 6/15/2043 | 65,295,000 | 3,370,000 | 1,632,375 | 5,002,375 |
| 12/15/2043 | 61,925,000 | 3,455,000 | 1,548,125 | 5,003,125 |
| 6/15/2044 | 58,470,000 | 3,540,000 | 1,461,750 | 5,001,750 |
| 12/15/2044 | 54,930,000 | 3,630,000 | 1,373,250 | 5,003,250 |
| 6/15/2045 | 51,300,000 | 3,720,000 | 1,282,500 | 5,002,500 |
| 12/15/2045 | 47,580,000 | 3,810,000 | 1,189,500 | 4,999,500 |
| 6/15/2046 | 43,770,000 | 3,905,000 | 1,094,250 | 4,999,250 |
| 12/15/2046 | 39,865,000 | 4,005,000 | 996,625 | 5,001,625 |
| 6/15/2047 | 35,860,000 | 4,105,000 | 896,500 | 5,001,500 |
| 12/15/2047 | 31,755,000 | 4,205,000 | 793,875 | 4,998,875 |
| 6/15/2048 | 27,550,000 | 4,315,000 | 688,750 | 5,003,750 |
| 12/15/2048 | 23,235,000 | 4,420,000 | 580,875 | 5,000,875 |
| 6/15/2049 | 18,815,000 | 4,530,000 | 470,375 | 5,000,375 |
| 12/15/2049 | 14,285,000 | 4,645,000 | 357,125 | 5,002,125 |
| 6/15/2050 | 9,640,000 | 4,760,000 | 241,000 | 5,001,000 |
| 12/15/2050 | 4,880,000 | 4,880,000 | 122,000 | 5,002,000 |
| **TOTAL** | | **$935,655,000** | **$434,436,207** | **$1,370,091,207** |

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2023 | $20,945,000 | $10,360,000 | $10,585,000 |
| 12/15/2023 | $10,585,000 | $10,585,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2029 | $11,650,000 | $5,760,000 | $5,890,000 |
| 12/15/2029 | $5,890,000 | $5,890,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $20,990,000 | $10,365,000 | $10,625,000 |
| 12/15/2037 | $10,625,000 | $10,625,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 21**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2033 | $26,590,000 | $13,130,000 | $13,460,000 |
| 12/15/2033 | $13,460,000 | $13,460,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 22**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2034 | $5,490,000 | $2,710,000 | $2,780,000 |
| 12/15/2034 | $2,780,000 | $2,780,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 23**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2035 | $900,000 | $445,000 | $455,000 |
| 12/15/2035 | $455,000 | $455,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 24**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2036 | $93,930,000 | $46,385,000 | $47,545,000 |
| 12/15/2036 | $47,545,000 | $47,545,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 25**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $62,695,000 | $30,960,000 | $31,735,000 |
| 12/15/2037 | $31,735,000 | $31,735,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2038 | $5,330,000 | $2,630,000 | $2,700,000 |
| 12/15/2038 | $2,700,000 | $2,700,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2039 | $5,600,000 | $2,765,000 | $2,835,000 |
| 12/15/2039 | $2,835,000 | $2,835,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2040 | $5,885,000 | $2,905,000 | $2,980,000 |
| 12/15/2040 | $2,980,000 | $2,980,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 4**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2041 | $6,180,000 | $3,050,000 | $3,130,000 |
| 12/15/2041 | $3,130,000 | $3,130,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 5**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2042 | $6,490,000 | $3,205,000 | $3,285,000 |
| 12/15/2042 | $3,285,000 | $3,285,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 6**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2043 | $37,745,000 | $3,370,000 | $34,375,000 |
| 12/15/2043 | $34,375,000 | $3,455,000 | $30,920,000 |
| 6/15/2044 | $30,920,000 | $3,540,000 | $27,380,000 |
| 12/15/2044 | $27,380,000 | $3,630,000 | $23,750,000 |
| 6/15/2045 | $23,750,000 | $3,720,000 | $20,030,000 |
| 12/15/2045 | $20,030,000 | $3,810,000 | $16,220,000 |
| 6/15/2046 | $16,220,000 | $3,905,000 | $12,315,000 |
| 12/15/2046 | $12,315,000 | $4,005,000 | $8,310,000 |
| 6/15/2047 | $8,310,000 | $4,105,000 | $4,205,000 |
| 12/15/2047 | $4,205,000 | $4,205,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 7**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2048 | $27,550,000 | $4,315,000 | $23,235,000 |
| 12/15/2048 | $23,235,000 | $4,420,000 | $18,815,000 |
| 6/15/2049 | $18,815,000 | $4,530,000 | $14,285,000 |
| 12/15/2049 | $14,285,000 | $4,645,000 | $9,640,000 |
| 6/15/2050 | $9,640,000 | $4,760,000 | $4,880,000 |
| 12/15/2050 | $4,880,000 | $4,880,000 | $0 |

# APPENDIX A

## DEFINITIONS

Whenever used in this Agreement, the following words and phrases shall have the following meanings:

"Actual Charge Collections" means the Charge Collections, which are calculated pursuant to Section 3.03(c) of the Servicing Agreement and section 6(d) of Annex 2 thereof to have been collected from Customers and deposited into the Allocation Account during a Reconciliation Period.

"Adjustment Date" means the date specified in an Adjustment Notice on which the adjusted Charge described in such Adjustment Notice shall take effect.

"Adjustment Notice" means any filing made with the Authority by the Servicer on behalf of the Bond Issuer to set or adjust the Charge, including the Issuance Advice Letter.

"Allocation Account" means the deposit accounts or other accounts designated by the Authority from time to time and controlled by the Allocation Agent, into which all payments from or on behalf of Customers are to be deposited and from which transfers of estimated Charge Collections and Remittance Shortfalls are to be made to the Collection Account and transfers of Estimated Other Payments are to be made to appropriate accounts of the Authority. Initially, the Allocation Account shall refer to the clearing account(s) that have been established by the Authority with J.P. Morgan Chase Bank.

"Allocation Agent" means the entity designated by the Authority (which may be the Authority) that agrees to control the Allocation Account in trust for the benefit of the Bond Trustee and the Authority Trustee, to accept all payments from or on behalf of Customers for deposit into the Allocation Account, to notify the Servicer on each Business Day of the amount deposited into the Allocation Account on the preceding Business Day, and, to the extent that funds are available in the Allocation Account, to transfer the estimated Charge Collections and Remittance Shortfalls from the Allocation Account to the Collection Account as instructed by the Servicer or the Bond Trustee in writing and to transfer the Estimated Other Payments as instructed by the Authority or the Authority Trustee. The initial Allocation Agent shall be the Authority.

"Annual Accountant's Report" has the meaning set forth in Section 3.07 of the Servicing Agreement.

"Annual True-up" has the meaning assigned to that term in Annex 1.

"Authority" means the Long Island Power Authority and any successor thereto.

"Authority Regulations" means all regulations, rules, tariffs and laws applicable to public utilities, owners of the T&D System Assets or Third Parties, as the case may be, and promulgated by, enforced by or otherwise within the jurisdiction of the Authority.

"Authority Trustee" means the trustee under the Authority's Electric System General Revenue Bond Resolution dated May 13, 1998.

"Basic Documents" means the Bond Indenture, the Sale Agreement, this Agreement, the Administration Agreement, the Continuing Disclosure Agreement and the Bond Purchase Agreement.

"Billing Month" means a calendar month during which the Charge is billed to Customers.

"Billing Period" means the period during which the electric transmission and distribution services reflected on a Customer's Bill were received by such Customer.

"Bills" means each of the regular monthly bills, summary bills and other bills issued to Customers for T&D Rates by the Servicer or by a Third Party.

"Bond" means any bond or other debt security issued pursuant to the Financing Order and the Bond Indenture.

"Bondholders" has the meaning specified in Section 1.01 of the Bond Indenture.

"Bond Balance" means, as of any date, the aggregate Outstanding Amount of all Bonds on such date.

"Bond Indenture" means the Bond Indenture, dated as of September 29, 2022, between the Bond Issuer and the Bond Trustee, as the same may be amended and supplemented from time to time.

"Bond Issuer" means the Utility Debt Securitization Authority.

"Bond Trustee" has the meaning specified in Section 1.01 of the Bond Indenture.

"Business Day" means any day other than a Saturday, a Sunday or a day on which banking institutions or trust companies in New York, New York, are authorized or obligated by law, regulation or executive order to remain closed.

"Certificate of Compliance" means the certificate referred to in Section 3.06 of this Agreement.

"Charge" means the Charge authorized in the Financing Order, as the same may be adjusted from time to time as provided in the Financing Order.

"Charge Collections" means the payments of the Charges by or on behalf of Customers.

"Closing Date" means September 29, 2022.

"Collateral" has the meaning specified in Section 1.01 of the Bond Indenture.

"Collection Account" means the account established and maintained by the Bond Trustee in accordance with Section 8.02(a) of the Bond Indenture and any subaccounts contained therein.

"Collection Period" means the period from and including the first day of a calendar month to but excluding the first day of the next calendar month.

"Customers" means consumers as defined in the Statute.

"Daily Remittance Date" means, if the Servicer has not satisfied the conditions of Section 5.11(b) of the Servicing Agreement, each Business Day commencing on the second Business Day following the date on which the Servicer begins remittance procedures under Section 3.03(a)(ii) of the Servicing Agreement.

"EMMA" has the meaning specified in Section 7.12 of the Servicing Agreement.

"ERISA" means the Employee Retirement Income Security Act of 1974.

"Estimated Charge Collections" means the estimated Charge Collections calculated as provided in Annex 2 of the Servicing Agreement.

"Estimated Other Payments" means all payments by or on behalf of Customers other than estimated Charge Collections and any Remittance Shortfalls net of any Excess Remittance.

"Excess Remittance" means the amount, if any, calculated for a particular Reconciliation Period, by which all Estimated Charge Collections remitted to the Collection Account during such Reconciliation Period exceed Actual Charge Collections received by the Servicer during such Reconciliation Period and taking into account any Excess Remittance or Remittance Shortfall previously paid during such Reconciliation Period.

"Excess Funds Subaccount" means any residual or excess funds subaccount of the Collection Account other than the Reserve Subaccount.

"Expected Amortization Schedule" means the Expected Amortization Schedule attached to this Agreement.

"Expected Final Payment Date" means the Payment Date on which all of the Bonds are scheduled to be paid in full.

"Final Maturity Date" means, with respect to any Tranche of Bonds, the date by which all principal and interest on that Tranche is required to be paid, as specified in the Bond Indenture.

"Fitch" means Fitch, Inc. or its successor.

"Financing Order" means the Restructuring Cost Financing Order No. 6 of the Authority adopted on May 18, 2022.

"Governmental Authority" means any nation or government, any federal, state, local or other political subdivision thereof and any court, administrative agency, or other instrumentality or entity exercising executive, legislative, judicial, regulatory or administrative function of government.

"Holder" or "Bondholder" means the Person in whose name a Bond is registered on the Bond Register, and to the extent specified by the Bond Indenture, the owners of bearer Bonds.

"Independent" has the meaning specified in Section 1.01 of the Bond Indenture.

"Insolvency Event" means, with respect to a specified Person, (a) the filing of a decree or order for relief by a court having jurisdiction in the premises in respect of such Person or any substantial part of its property in an involuntary case under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or appointing a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official for such Person or for any substantial part of its property, or ordering the winding-up or liquidation of such Person's affairs, and such decree or order shall remain unstayed and in effect for a period of 60 consecutive days; or (b) the commencement by such Person of a voluntary case under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or the consent by such Person to the entry of an order for relief in an involuntary case under any such law, or the consent by such Person to the appointment of or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official for such Person or for any substantial part of its property, or the making by such Person of any general assignment for the benefit of creditors, or the failure by such Person generally to pay its debts as such debts become due.

"Investment Company Act" means the Investment Company Act of 1940, as amended.

"Issuance Advice Letter" means the initial Issuance Advice Letter, dated September 21, 2022, filed by the Servicer with the Authority pursuant to the Statute.

"Issuer Annex" means Annex 1 of the Servicing Agreement.

"Lien" has the meaning specified in Section 1.01 of the Bond Indenture.

"LIPA" has the meaning set forth in the preamble to this Agreement.

"Losses" means collectively, any and all liabilities, obligations, losses, damages, payments, costs or expenses of any kind whatsoever.

"Mid-year Review" has the meaning assigned to that term in Annex 1.

"Mid-year True-up" has the meaning assigned to that term in Annex 1.

"Monthly Servicer Certificate" has the meaning assigned to that term in Annex 1 to the Servicing Agreement.

"Moody's" means Moody's Investors Service Inc. or its successor.

"Officer's Certificate" means a certificate of the Servicer signed by a Responsible Officer.

"Ongoing Financing Costs" has the meaning assigned to that term in the Financing Order.

"Opinion of Counsel" means one or more written opinions of counsel who may be an employee of or counsel to the party providing such opinion(s) of counsel, which counsel shall be reasonably acceptable to the party receiving such opinion(s) of counsel.

"Optional True-up" has the meaning assigned to that term in Annex I.

"Operation Services Agreement" means the Amended and Restated Operation Services Agreement between PSE&G Long Island LLC and LIPA, as amended from time to time.

"Outstanding" has the meaning specified in Section 1.01 of the Bond Indenture.

"Outstanding Amount" has the meaning specified in Section 1.01 of the Bond Indenture.

"Payment Date" means, with respect to any Tranche of Bonds, the dates specified in the Bond Indenture for the payment of interest on the Bonds; or if any such date is not a Business Day, the next Business Day.

"Person" has the meaning specified in Section 1.01 of the Bond Indenture.

"Principal Balance" means, as of any Payment Date, the sum of the outstanding principal amount of the Bonds.

"Proceeding" means any suit in equity, action at law or other judicial or administrative proceeding.

"Projected Bond Balance" means, as of any Payment Date, the sum of the projected outstanding principal amount of the Bonds for such Payment Date set forth in the Expected Amortization Schedule.

"Rating Agency" means, as of any date, any rating agency rating the Bonds of any Tranche at the time of issuance thereof at the request of the Bond Issuer. If no such organization or successor is any longer in existence, "Rating Agency" shall be a nationally recognized statistical rating organization or other comparable Person designated by the Bond Issuer, notice of which designation shall be given to the Bond Trustee, the Authority and the Servicer.

"Rating Agency Condition" means, with respect to any action, not less than ten Business Days' prior written notification to each Rating Agency of such action, and written confirmation from each of Standard & Poor's and Moody's to the Servicer, the Bond Trustee and the Bond Issuer that such action will not result in a suspension, reduction or withdrawal of the then current rating by such Rating Agency of any Tranche of Bonds and that prior to the taking of the proposed action no other Rating Agency shall have provided written notice to the Bond Issuer that such action has resulted or would result in the suspension, reduction or withdrawal of the then current rating of any Tranche of Bonds; provided, that if within such ten Business Day period, any Rating Agency (other than Standard & Poor's) has neither replied to such notification nor responded in a manner that indicates that such Rating Agency is reviewing and considering the notification, then (i) the Bond Issuer shall be required to confirm that such Rating Agency has received the Rating Agency Condition request, and if it has, promptly request the related Rating Agency Condition confirmation and (ii) if the Rating Agency neither replies to such notification nor responds in a manner that indicates it is reviewing and considering the notification within five Business Days following such second request, the applicable Rating Agency Condition requirement shall not be deemed to apply to such Rating Agency. For the purposes of this definition, any confirmation, request, acknowledgment or approval that is required to be in writing may be in the form of electronic mail or a press release (which may contain a general waiver of a Rating Agency's right to review or consent).

"Reconciliation Period" means the twelve-month period ending the last day of the Collection Period preceding the calculation of Remittance Shortfalls or Excess Remittances under Section 3.03(c) the Servicing Agreement; provided, that the initial Reconciliation Period shall commence on the Closing Date and may be less than twelve months.

"Remittance" means each transfer hereunder of estimated Charge Collections or Remittance Shortfalls from the Allocation Account to the Collection Account.

"Remittance Date" means each Business Day on which a Remittance is to be made by the Servicer pursuant to Section 3.03 of this Agreement.

"Remittance Shortfall" means the amount, if any, calculated for a particular Reconciliation Period, by which Actual Charge Collections received by the Servicer during such Reconciliation Period exceed all Estimated Charge Collections remitted to the Collection Account during such Reconciliation Period and taking into account any Excess Remittance or Remittance Shortfall previously paid during such Reconciliation Period.

"Required Debt Service Reserve Level" has the meaning specified in Section 1.01 of the Bond Indenture.

"Required Reserve Level" has the meaning specified in Section 1.01 of the Bond Indenture.

"Reserve Subaccount" has the meaning specified in Section 1.01 of the Bond Indenture.

"Responsible Officer" means the chief executive officer, the president, any vice president, the treasurer, any assistant treasurer, the clerk, any assistant clerk, the controller or the director of finance and cash management of the Servicer.

"Restructuring Property" means the Restructuring Property that is created pursuant to the Financing Order and is sold by the Seller to the Bond Issuer under the Sale Agreement.

"Restructuring Property Documentation" means all documents relating to the Restructuring Property, including copies of the Financing Order and all documents filed with the Authority in connection with any Adjustment Notice.

"Retirement of the Bonds" means the day on which the final payment is made to the Bond Trustee in respect of the last outstanding Bond.

"Rule 15c2-12" or the "Rule" means Rule 15c2-12 of the SEC under the Securities Exchange Act of 1934, as amended.

"Sale Agreement" means the Restructuring Property Purchase and Sale Agreement dated as of September 29, 2022, between the Long Island Power Authority, as Seller, and the Bond Issuer, as the same may be amended and supplemented from time to time.

"Scheduled Maturity Date" has the meaning specified in Section 1.01 of the Bond Indenture.

"SEC" means the U.S. Securities and Exchange Commission.

"Seller" means the Long Island Power Authority, a New York public authority, and its permitted successors and assigns under the Sale Agreement.

"Semiannual Servicer Certificate" has the meaning assigned to that term in Annex 1 to this Agreement.

"Service Area" means the geographical area within which LIPA provided electric distribution services as of [July 29, 2013].

"Servicer" means LIPA, as the servicer of the Restructuring Property, or each successor (in the same capacity) pursuant to Section 5.03 or 6.04 of this Agreement.

"Servicer Default" means an event specified in Section 6.01 of this Agreement.

"Servicing Fee" has the meaning set forth in Section 5.07 of this Agreement.

"Sponsor" means the Authority and its permitted successors and assigns under the Sale Agreement.

"Standard & Poor's" means Standard & Poor's, a division of The McGraw-Hill Companies, Inc. or its successor.

"Statute" means Part B of Chapter 173, Laws of New York, 2013, as amended to the date hereof.

"T&D System Assets" means the T&D system assets as defined in the Statute.

"T&D Rates" means the rates and charges for electric transmission and distribution services in the Service Area. "T&D Rates" shall not include charges for the generation or resale of electricity or any charges imposed to fund public purpose programs.

"Termination Notice" has the meaning assigned to that term in Section 6.01 of this Agreement.

"Third Party" means an entity (other than the Servicer and its agents, subservicers or subcontractors) who bills and collects the Charge to and from Customers in accordance with the Statute, Authority Regulations and any order of the Authority.

"Tranche" or "Tranche of Bonds" has the meaning specified in Section 1.01 of the Bond Indenture.

"True-Up Adjustment" means each adjustment to the Charge made in accordance with Annex 1 of this Agreement.

"Written Notice", "written notice" or "notice in writing" means notice in writing which may be delivered by hand or first class mail and also means electronic transmission.

"17g-5 Website" has the meaning specified in Section 1.01 of the Bond Indenture.

**Attachment 2**

# ADMINISTRATION AGREEMENT

# ADMINISTRATION AGREEMENT

This Administration Agreement, dated as of September 29, 2022, is made by and between Utility Debt Securitization Authority, a special purpose corporate municipal instrumentality, body corporate and politic, political subdivision and public benefit corporation of the State of New York (the "Bond Issuer"), and the Long Island Lighting Company, a New York corporation doing business under the name of LIPA ("LIPA"), as Administrator (the "Administrator").

## RECITALS

A. The Bond Issuer is issuing the Bonds pursuant to the Bond Indenture dated as of September 29, 2022 (as amended, modified or supplemented from time to time in accordance with the provisions thereof, the "Bond Indenture"). Capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Bond Indenture or Servicing Agreement (hereinafter defined).

B. The Bond Issuer has entered into certain agreements in connection with the issuance of the Bonds, including (i) a Restructuring Property Purchase and Sale Agreement dated as of September 29, 2022 (the "Sale Agreement"), between the Bond Issuer and the Long Island Power Authority, as Seller (in such capacity, the "Seller"), (ii) a Restructuring Property Servicing Agreement dated as of September 29, 2022 (the "Servicing Agreement"), between the Bond Issuer and LIPA, as Servicer (in such capacity, the "Servicer"), (iii) a Bond Purchase Agreement dated as of September 16, 2022, as amended on September 20, 2022, (the "Bond Purchase Agreement"), among the Bond Issuer and the Underwriters named therein, and (iv) the Bond Indenture. The Sale Agreement, the Servicing Agreement, the Bond Purchase Agreement and the Bond Indenture, all as amended or modified from time to time, are herein referred to collectively as the "Related Agreements".

C. Pursuant to the Related Agreements, the Bond Issuer is required to perform certain duties in connection with the Bonds and the collateral therefor pledged pursuant to the Bond Indenture (the "Collateral") and to maintain its existence and comply with applicable laws.

D. The Bond Issuer desires to have the Administrator perform certain duties of the Bond Issuer referred to in the preceding clause, and to provide such additional services consistent with the terms of this Agreement and the Related Agreements as the Bond Issuer may from time to time request.

E. The Administrator is willing to perform such services and provide such facilities for the Bond Issuer on the terms set forth herein.

NOW, THEREFORE, in consideration of the mutual covenants contained herein, and other good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, the parties agree as follows:

# ARTICLE I.
## Duties of Administrator

Section 1.01 Appointment of Administrator: Acceptance of Appointment. The Bond Issuer hereby appoints the Administrator, and the Administrator hereby accepts such appointment, to perform the Administrator's obligations pursuant to this Agreement on behalf of and for the benefit of the Bond Issuer in accordance with the terms of this Agreement and applicable law.

Section 1.02 Duties of the Administrator. The Administrator agrees to perform all its duties as Administrator hereunder in accordance with the terms of this Agreement and applicable law.

(a) To the extent not required to be performed by the Servicer, the Administrator shall provide for the performance by the Bond Issuer of its obligations under each of the Related Agreements and shall prepare for execution by the Bond Issuer, or shall cause the preparation by other appropriate Persons (including third parties with respect to professional services, to the extent required or contemplated in accordance with the terms of this Agreement) of all such documents, reports, filings, instruments, notices, certificates and opinions as it shall be the duty of the Bond Issuer to prepare, file or deliver pursuant to the Related Agreements. In furtherance of and without limiting the generality of the foregoing, the Administrator shall provide for the performance by the Bond Issuer of its duties pursuant to the Bond Indenture, including such of the foregoing as are required with respect to the following matters under the Bond Indenture (references are to sections of the Bond Indenture):

(i) confirmation that any non-responding Rating Agency has received the Rating Agency Condition request, and if it has, promptly request the related Rating Agency Condition confirmation (for a definition of Rating Agency Condition see Section 1.01);

(ii) the preparation of or obtaining of the documents and instruments required for authentication of the Bonds, if any, and delivery of the same to the Bond Trustee and such other actions on behalf of the Bond Issuer as are necessary for the issuance and delivery of the Bonds, whether for original issuance, exchanges, transfers, replacements or redemptions (Sections 2.03, 2.05, 2.06, 2.10 and 10.07);

(iii) the duty to cause a Bond Register to be kept and to give the Bond Trustee notice of any appointment of a new Bond Registrar and the location, or change in location, of the Bond Register (Section 2.05);

(iv) the fixing or causing to be fixed of any special record date and the notification of each affected Bondholder with respect to special record dates, payment dates, and the amount of defaulted interest (plus interest on such defaulted interest) to be paid, if any (Section 2.08(c));

(v) advising the Bond Trustee of an election to terminate the book-entry system through a Clearing Agency with respect to the Bonds (Section 2.16(f));

(vi) maintenance of an office or agency in the Borough of Manhattan, City of New York, New York, where Bonds may be surrendered for registration of transfer or exchange, which may be the Bond Trustee (Section 3.02);

(vii) the duty to cause newly appointed Paying Agents, if any, to deliver to the Bond Trustee the instrument specified in the Bond Indenture regarding funds held in trust (Section 3.03);

(viii) the direction to Paying Agents to pay to the Bond Trustee all sums held in trust by such Paying Agents (Section 3.03);

(ix) to the extent not required to be performed by the Servicer, the preparation of all supplements and amendments to the Bond Indenture, filings pursuant to the Statute or the Financing Order, instruments of further assurance and other instruments, necessary to protect the Collateral (Section 3.04);

(x) the identification to the Bond Trustee in an Officer's Certificate of any Person with whom the Bond Issuer has contracted to perform its duties under the Bond Indenture (Section 3.05(a));

(xi) the delivery of notice to the Bond Trustee and the Rating Agencies of each Event of Default and each default by the Servicer or Seller of its obligations under the Servicing Agreement or the Sale Agreement, respectively (Sections 3.05(c), 3.12 and 5.01);

(xii) notification of the appointment of any successor Servicer (Section 3.05(e));

(xiii) the preparation and filing of all documents required under the Statute relating to the transfer of the ownership or security interest in the Restructuring Property (Section 3.04);

(xiv) the preparation of an Officer's Certificate and Independent Certificate relating to (i) the satisfaction and discharge of the Bond Indenture under Section 4.01 of the Bond Indenture or (ii) a Legal Defeasance under Section 4.02 of the Bond Indenture;

(xv) sending a copy of each Certificate of Compliance delivered to it pursuant to Section 3.06 of the Servicing Agreement and Annual Accountant's Report delivered to it pursuant to Section 3.07 of the Servicing Agreement to the Bond Trustee, the Bondholders and the Rating Agencies and to the Servicer. (Section 6.06(c));

(xvi) the furnishing to the Bond Trustee of (i) each Record Date and (ii) the names and addresses of Bondholders during any period when the Bond Trustee is not the Bond Registrar (Section 7.03);

(xvii) to the extent not required to be performed by the Servicer, the opening of one or more segregated trust accounts in the Bond Trustee's name, the preparation of Issuer Orders, and the obtaining of Opinions of Counsel and the taking of all other actions necessary with respect to investment and reinvestment of funds in the Collection Account including transfer of the Collection Account to an Eligible Institution if it ceases to be maintained at an Eligible Institution (Sections 8.02 and 8.03);

(xviii) to the extent not required to be performed by the Servicer, the preparation, obtaining or filing of the instruments, opinions and certificates and other documents required for the release of collateral (Sections 8.04 and 8.05);

(xix) appointment of a firm of Independent registered public accountants of recognized national reputation for purposes of preparing and delivering the reports or certificates of such accountants required by the Bond Indenture and, upon any resignation by such firm, providing written notice thereof to the Bond Trustee and promptly appointing a successor thereto that shall also be a firm of Independent registered public accountants of recognized national reputation (Section 8.06);

(xx) the preparation of Issuer Orders and the obtaining of Officers' Certificates with respect to the execution of supplemental bond indentures (Sections 9.01, 9.02 and 9.03);

(xxi) the preparation of new Bonds conforming to any supplemental bond indenture (Section 9.04);

(xxii) in the case of any redemption of Bonds at the direction of the Bond Issuer, giving written notice to the Bond Trustee of the Bond Issuer's direction to redeem such Bonds (Section 10.03);

(xxiii) the notification of the Bond Trustee of any notice received by the Bond Issuer from the Bondholders (Section 11.02)); and

(xxiv) interacting with the Allocation Agent with respect to Excess Remittances and Remittance Shortfalls (Section 8.02(c)).

(b) The Administrator shall also furnish the Bond Issuer with ordinary clerical, bookkeeping and other administrative services necessary and appropriate for the Bond Issuer, including, without limitation, the following services:

(i) to the extent not required to be performed by the Servicer, the preparation and, after execution by the Bond Issuer, the filing with the applicable Governmental Authorities, the Rating Agencies and the Bond Trustee of the annual reports, periodic reports, applications, certificates and other filings and of the information, documents, statements and other reports required to be filed on a periodic basis with, and summaries thereof as may be required by rules and regulations prescribed by, the applicable Governmental Authorities;

(ii) maintain at the facilities (referenced in Section 2.01 below) general accounting records of the Bond Issuer (the "Account Records"), subject to year-end audit, in accordance with generally accepted accounting principles, separate and apart from its own accounting records, prepare or cause to be prepared such quarterly and annual financial statements as may be necessary or appropriate and arrange for year-end audits of the Bond Issuer's financial statements by the Bond Issuer's independent accountants;

(iii) prepare for execution by the Bond Issuer and cause to be filed such income, franchise or other tax returns of the Bond Issuer as may be required to be filed by applicable law (the "Tax Returns"), perform any obligations of the Bond Issuer under its tax covenants and agreements pursuant to Bond Indenture Section 3.14 and cause to be paid on behalf of the Bond Issuer from the Bond Issuer's funds any taxes required to be paid by the Bond Issuer under applicable law;

(iv) prepare or cause to be prepared for execution by the Bond Issuer's trustees minutes of the meetings of the Bond Issuer's trustees and such other documents deemed appropriate by the Bond Issuer to maintain the separate public authority existence and good standing of the Bond Issuer (the "Bond Issuer Minutes") or otherwise required under the Related Agreements (together with the Account Records, the Tax Returns, the Bond Issuer Minutes and its by-laws, the "Bond Issuer Documents"), and any other documents deliverable by the Bond Issuer thereunder or in connection therewith; and

(v) hold, maintain and preserve at the facilities (or such other place as shall be required by any of the Related Agreements) executed copies (to the extent applicable) of the Bond Issuer Documents and other documents executed by the Bond Issuer thereunder or in connection therewith.

(c) To the full extent allowable under applicable law, the Administrator shall enforce each of the rights of the Bond Issuer under the Related Agreements;

(d) The Administrator shall provide for the defense, at the direction of the Bond Issuer's Trustees, of any action, suit or proceeding brought against the Bond Issuer or affecting the Bond Issuer or any of its assets or the Collateral. (Bond Indenture Sections 3.04(d) and 6.07).

Section 1.03 Additional Duties. (a) In addition to the duties of the Administrator set forth above, the Administrator shall (1) undertake such other administrative services as may be appropriate, necessary or requested by the Bond Issuer and (2) provide such other services as are incidental to those set forth in Section 1.02 or this Section 1.03 or as the Bond Issuer and

Administrator may agree. As part of its administrative services, the Administrator shall obtain and maintain a directors' and officers' insurance policy covering the trustees of the Bond Issuer (which policy may cover the officers of the Bond Issuer as well), the Administrator shall pay the premiums therefor as a reimbursable expense hereunder to the extent there are insufficient funds on deposit in the Collection Account to pay such premiums when due in accordance with the priorities specified in the Bond Indenture, and the reimbursement of such expense shall have the priority specified in the Bond Indenture for such premiums. Subject to Section 5.01 of this Agreement, and in accordance with the directions of the Bond Issuer, the Administrator shall administer, perform or supervise the performance of such other activities in connection with the Collateral and the Related Agreements as are not covered by any of the foregoing provisions and as are expressly requested by the Bond Issuer and are reasonably within the capability of the Administrator.

(b) In carrying out the foregoing duties or any of its other obligations under this Agreement, the Administrator may enter into transactions with or otherwise deal with any of its Affiliates; provided, however, that the terms of any such transactions or dealings shall be, in the Administrator's reasonable opinion, no less favorable to the Bond Issuer than would be available from unaffiliated parties.

(c) In providing the services under this Article I and as otherwise provided under this Administration Agreement, the Administrator will not knowingly take any actions on behalf of the Bond Issuer which (i) the Bond Issuer is prohibited from taking under the Related Agreements, or (ii) would cause the Bond Issuer to be in violation of any federal, state or local law. Promptly upon obtaining knowledge that it has taken any such actions, the Administrator shall take all reasonable steps to cure such breach or violation and to cause the Bond Issuer to be in compliance with the applicable Related Agreement or law.

(d) The Administrator covenants that with respect to Bonds the interest on which is intended to be excluded from gross income for federal income tax purposes (hereinafter "Tax Exempt Bonds") it shall comply with the tax certificates to be executed and delivered by it in connection with the issuance of the Tax Exempt Bonds and with letters of instruction, if any, delivered by bond counsel in connection with the issuance of the Tax Exempt Bonds, as such tax certificates and letters may be amended from time to time. Notwithstanding anything else in this Agreement to the contrary, the covenants of this Section 1.03(d) shall survive the payment, redemption or defeasance of the Tax Exempt Bonds and the termination of this Agreement. For the avoidance of doubt, all the Bonds constitute Tax Exempt Bonds.

(e) In performing its duties hereunder, the Administrator shall use the same degree of care and diligence that the Administrator exercises with respect to performing such duties for its own account and, if applicable, for others.

(f) The Administrator agrees to comply with the provisions of Article XI of the Bond Issuer's by-laws, including any amendments thereof made with the consent of the Administrator, which consent shall not be unreasonably withheld, to the extent that such provisions are applicable to its duties as agent for the Bond Issuer hereunder and, to the extent that the Administrator employs others to perform such duties in accordance with this Agreement, the Administrator will require that such others comply with such applicable provisions.

Section 1.04 Non-Ministerial Matters. (a) With respect to matters that in the reasonable judgment of the Administrator are non-ministerial, the Administrator shall not take any action unless the Administrator shall have notified the Bond Issuer of the proposed action and the Bond Issuer shall have consented. For the purpose of the preceding sentence, “non-ministerial matters” shall include, without limitation:

(i) the amendment of, or any supplement to, the Bond Indenture;

(ii) the initiation of any claim or lawsuit by the Bond Issuer and the compromise of any action, claim or lawsuit brought by or against the Bond Issuer (other than in connection with the collection of the Charge);

(iii) the amendment, change or modification of the Related Agreements;

(iv) the appointment of successor Bond Registrars, successor Paying Agents and successor Bond Trustees pursuant to the Bond Indenture or the appointment of successor Administrators or successor Servicers, or the consent to the assignment by the Bond Registrar, Paying Agent or Bond Trustee of its obligations under the Bond Indenture (Bond Indenture Section 6.08); and

(v) the removal of the Bond Trustee (Bond Indenture Section 6.08).

(b) Notwithstanding anything to the contrary in this Agreement, the Administrator shall not be obligated to, and hereby agrees that it shall not, take any action that the Bond Issuer directs the Administrator not to take on its behalf.

## ARTICLE II.
## Facilities

Section 2.01 Facilities. During the term of this Agreement, the Administrator shall make available to or provide the Bond Issuer with such facilities and reasonable ancillary services as are necessary to conduct the business of the Bond Issuer and to comply with the terms of the Related Agreements. Such facilities shall include office space to serve as the principal place of business of the Bond Issuer. Initially such office space will be located at 333 Earle Ovington Blvd., Ste. 403, Uniondale, New York 11553. All facilities provided to the Bond Issuer hereunder shall be provided without warranty of any kind.

## ARTICLE III.
## Compensation

Section 3.01 Compensation. As compensation for the performance of the Administrator’s obligations under this Agreement, including the provision of facilities pursuant to Section 2.01, the Administrator shall be entitled to an annual fee (the “Administration Fee”) equal to $100,000 payable in equal semiannual installments on each Payment Date as defined in Section 2.02(g)(iii) of the Bond Indenture. In addition, to the extent not included in the Administration Fee, the Bond Issuer shall reimburse the Administrator for all filing fees and expenses, legal fees, fees of outside auditors and other out-of-pocket expenses incurred by the

Administrator in the course of performing its duties hereunder. The Administrator's compensation and other expenses payable hereunder shall be paid from the Collection Account pursuant to, and in accordance with, Section 8.02(e) of the Bond Indenture, and the Administrator shall have no recourse against the Bond Issuer for payment of such amounts other than in accordance with Section 8.02 of the Bond Indenture.

## ARTICLE IV.
## Additional Information

Section 4.01 Additional Information To Be Furnished to Bond Issuer. The Administrator shall furnish to the Bond Issuer from time to time such additional information regarding the Collateral as the Bond Issuer shall reasonably request.

## ARTICLE V.
## Miscellaneous Provisions

Section 5.01 Independence of Administrator. For all purposes of this Agreement, the Administrator shall be an independent contractor and shall not be subject to the supervision of the Bond Issuer with respect to the manner in which it accomplishes the performance of its obligations hereunder. Unless expressly authorized by the Bond Issuer, the Administrator shall have no authority to act for or represent the Bond Issuer in any way and shall not otherwise be deemed an agent of the Bond Issuer.

Section 5.02 No Joint Venture. Nothing contained in this Agreement shall (a) constitute the Administrator and the Bond Issuer as members of any partnership, joint venture, association, syndicate, unincorporated business or other separate entity, (b) be construed to impose any liability as such on any of them or (c) be deemed to confer on any of them any express, implied or apparent authority to incur any obligation or liability on behalf of the others.

Section 5.03 Other Activities of Administrator. Nothing herein shall prevent the Administrator or its Affiliates from engaging in other businesses or, in its sole discretion, from acting in a similar capacity as an administrator for any other person or entity even though such person or entity may engage in business activities similar to those of the Bond Issuer.

Section 5.04 Term of Agreement: Resignation and Removal of Administrator. (a) This Agreement shall continue in force for one year and one day after the retirement of all Bonds issued pursuant to the Bond Indenture.

(b) Subject to Sections 5.04(e) and 5.04(f), the Administrator may resign its duties hereunder by providing the Bond Issuer with at least 60 days prior written notice.

(c) Subject to Sections 5.04(e) and 5.04(f), the Bond Issuer may remove the Administrator without cause by providing the Administrator with at least 60 days prior written notice.

(d) Subject to Sections 5.04(e) and 5.04(f), at the sole option of the Bond Issuer, the Administrator may be removed immediately upon written notice of termination from the Bond Issuer to the Administrator if any of the following events shall occur:

(i) the Administrator shall default in the performance of any of its duties under this Agreement and, after notice of such default, shall not cure such default within ten days (or, if such default is curable but cannot be cured in such time, shall not give within ten days such assurance of cure as shall be reasonably satisfactory to the Bond Issuer);

(ii) a court having jurisdiction in the premises shall enter a decree or order for relief, and such decree or order shall not have been vacated within 60 days, in respect of the Administrator in any involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect or appoint a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official for the Administrator or any substantial part of its property or order the winding-up or liquidation of its affairs; or

(iii) the Administrator shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, shall consent to the entry of an order for relief in an involuntary case under any such law, or shall consent to the appointment of a receiver, liquidator, assignee, trustee, custodian, sequestrator or similar official for the Administrator or any substantial part of its property, shall consent to the taking of possession by any such official of any substantial part of its property, shall make any general assignment for the benefit of creditors or shall fail generally to pay its debts as they become due.

The Administrator agrees that if any of the events specified in clause (ii) or (iii) of this Section shall occur, it shall give written notice thereof to the Bond Issuer and the Bond Trustee within seven days after the happening of such event.

(e) No resignation or removal of the Administrator pursuant to this Section 5.04 shall be effective until (i) a successor Administrator shall have been appointed by the Bond Issuer and (ii) such successor Administrator shall have agreed in writing to be bound by the terms of this Agreement in the same manner as the Administrator is bound hereunder. The Bond Issuer shall promptly provide written notice to each of the Rating Agencies prior to the effectiveness of any resignation or removal of the Administrator.

(f) The appointment of any successor Administrator shall be effective only after satisfaction of the Rating Agency Condition with respect to the proposed appointment.

Section 5.05 Action upon Termination, Resignation or Removal. Promptly upon the effective date of termination of this Agreement pursuant to Section 5.04(a) or the resignation or removal of the Administrator pursuant to Sections 5.04(b) or 5.04(c), respectively, the Administrator shall be entitled to be paid all fees accrued to it and expenses accrued by it in the performance of its duties hereunder through the date of such termination, resignation or removal, to the extent permitted under Article III. The Administrator shall forthwith upon such termination pursuant to Section 5.04(a) deliver to the Bond Issuer all property and documents of or relating to the Collateral then in the custody of the Administrator. In the event of the resignation or removal of the Administrator pursuant to Sections 5.04(b) or 5.04(c), respectively, the Administrator shall cooperate with the Bond Issuer and take all reasonable steps requested to assist the Bond Issuer in making an orderly transfer of the duties of the Administrator.

Section 5.06 Notices. Unless otherwise specifically provided herein, all notices, directions, consents and waivers required under the terms and provisions of this Administration Agreement shall be in English and in writing, and any such notice, direction, consent or waiver may be given by United States mail, courier service, facsimile transmission or electronic mail (confirmed by telephone, United States mail or courier service in the case of notice by facsimile transmission or electronic mail) or any other customary means of communication, and any such notice, direction, consent or waiver shall be effective when delivered, or if mailed, three days after deposit in the United States mail with proper postage for ordinary mail prepaid:

(a) if to the Bond Issuer, to:

Utility Debt Securitization Authority
c/o LIPA, as Administrator
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(b) if to the Administrator, to:

LIPA
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(c) if to the Bond Trustee, to:

The Bank of New York Mellon
385 Rifle Camp Road – 3rd Floor
Woodland Park, NJ 07424
Attention: Frederic Belen
Telephone: (973) 247-4395
Telecopy: (732) 667-9205
Email: frederic.belen@bnymellon.com

or to such other address as any party shall have provided to the other parties in writing. Any notice required to be in writing hereunder shall be deemed given if such notice is mailed by certified mail, postage prepaid, telecopied or hand-delivered to the address of such party as provided above, except that notices to the Bond Trustee are effective only upon receipt.

Section 5.07 Amendments. This Agreement may be amended in writing by the Administrator and the Bond Issuer with the written consent of the Bond Trustee, but without the consent of any of the Bondholders, to cure any ambiguity, to correct or supplement any provisions in this Agreement or for the purpose of adding any provisions to or changing in any manner or eliminating any of the provisions in this Agreement or of modifying in any manner the rights of the Bondholders; provided, however, that such action shall not, as evidenced by an Officer's Certificate delivered to the Bond Trustee, adversely affect in any material respect the interests of any Bondholder.

This Agreement may also be amended in writing from time to time by the Administrator and the Bond Issuer with the written consent of the Bond Trustee and, subject to the first paragraph of this Section 5.07, the written consent of the Holders of Bonds evidencing not less than a majority of the Outstanding Amount of the Bonds of all Series, for the purpose of adding any provisions to or changing in any manner or eliminating any of the provisions of this Agreement or of modifying in any manner the rights of the Bondholders; provided, however, that no such amendment shall increase or reduce in any manner the amount of, or accelerate or delay the timing of, Charge Collections without the consent of the Holders of all the outstanding Bonds.

Prior to the effectiveness of any such amendment, the Administrator shall provide written notice of such amendment to each of the Rating Agencies and promptly after the execution of any such amendment and the requisite consents, the Administrator shall furnish a copy of such amendment to the Bond Trustee and each of the Rating Agencies.

Approval by Bondholders of the substance of any proposed amendment or consent shall constitute sufficient consent of the Bondholders pursuant to this Section, and it shall not be necessary that Bondholders approve of the particular form of any amendment or consent.

Prior to its consent to any amendment to this Agreement, the Bond Trustee shall be entitled to receive and rely upon an Opinion of Counsel stating that such amendment is authorized or permitted by this Agreement. The Bond Trustee may, but shall not be obligated to, enter into any such amendment which affects the Bond Trustee's own rights, duties or immunities under this Agreement or otherwise.

Section 5.08 Successors and Assigns. Except as provided below and in Section 5.17, this Agreement may not be assigned by the Administrator unless such assignment is previously consented to in writing by the Bond Issuer and the Bond Trustee and is subject to the satisfaction of the Rating Agency Condition in respect thereof. An assignment with such consent and satisfaction, if accepted by the assignee, shall bind the assignee hereunder in the same manner as the Administrator is bound hereunder. This Agreement may be assigned by the Administrator without the consent of the Bond Issuer and the Bond Trustee to a corporation or other organization that is a successor (by merger, consolidation or purchase of assets) to the Administrator, provided that such successor organization executes and delivers to the Bond Issuer and the Bond Trustee an agreement in which such corporation or other organization agrees to be bound hereunder by the terms of said assignment in the same manner as the Administrator is bound hereunder and the Rating Agency Condition is satisfied. Subject to the foregoing, this Agreement shall bind any successors or assigns of the parties hereto. Nothing in this Agreement shall prevent the Administrator from subcontracting with other persons or entities to perform all or part of its duties under this Agreement, but such subcontracting shall not release the Administrator from any of its obligations under this Agreement. The Administrator shall provide prompt written notice of any such subcontracting to each of the Rating Agencies.

Section 5.09 Limitations on Rights of Others. The provisions of this Agreement are solely for the benefit of the Administrator, the Bond Issuer, the Bond Trustee, the Bondholders and the other Persons expressly referred to herein. The Bondholders shall be entitled to enforce their rights and remedies against the Administrator under this agreement solely through a cause of action brought for their benefit by the Bond Trustee, and nothing in this Agreement, whether express or implied, shall be construed to give to any other Person any legal or equitable right, remedy or claim in the Restructuring Property or under or in respect of this Agreement or any covenants, conditions or provisions contained herein, except for the indemnities specifically provided in Section 5.15. The Persons listed in this section as having the benefit of this Agreement and the indemnified Persons listed in Section 5.15 shall have rights of enforcement with respect to this Agreement.

Section 5.10 GOVERNING LAW. THIS AGREEMENT SHALL BE CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REFERENCE TO ITS CONFLICT OF LAW PROVISIONS AND THE OBLIGATIONS, RIGHTS AND REMEDIES OF THE PARTIES HEREUNDER SHALL BE DETERMINED IN ACCORDANCE WITH SUCH LAWS.

Section 5.11 Headings. The section headings hereof have been inserted for convenience of reference only and shall not be construed to affect the meaning, construction or effect of this Agreement.

Section 5.12 Counterparts. This Agreement may be executed in counterparts, each of which when so executed shall together constitute but one and the same agreement.

Section 5.13 Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 5.14 Non-Petition Covenant. Notwithstanding any prior termination of this Agreement or the Bond Indenture, but subject to the right of a court in New York to order the sequestration and payment of revenues arising with respect to the Restructuring Property notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to any person or entity pursuant to Section 7.1(d) of the Statute, the Administrator, solely in its capacity as a creditor of the Bond Issuer, shall not, prior to the date which is one year and one day after the termination of the Bond Indenture with respect to the Bond Issuer, petition or otherwise invoke or cause the Bond Issuer to invoke the process of any court or government authority for the purpose of commencing or sustaining an involuntary case against the Bond Issuer under any Federal or state bankruptcy, insolvency or similar law or appointing a receiver, liquidator, assignee, trustee, custodian, sequestrator or other similar official of the Bond Issuer or any substantial part of the property of the Bond Issuer, or, to the fullest extent permitted by law, ordering the winding up or liquidation of the affairs of the Bond Issuer.

Section 5.15 Indemnification. The Administrator shall indemnify the Bond Issuer, the Bond Trustee, and their respective trustees, officers, officials, directors, employees and agents (each an "Indemnified Person") for, and defend and hold harmless each such Person from and against, any and all liabilities, obligations, actions, suits, claims, losses, damages, payments, costs or expenses of any kind whatsoever that may be imposed on, incurred by or asserted against any such Person as a result of the Administrator's willful misconduct or negligence in the performance of its duties or observance of its covenants under this Agreement. The Bondholders shall be entitled to enforce their rights and remedies against the Administrator under this indemnification solely through a cause of action brought for their benefit by the Bond Trustee. The Administrator will not, without the prior written consent of the Indemnified Person, settle or compromise or consent to the entry of any judgment with respect to any pending or threatened claim, action, suit or proceeding in respect of which indemnification may be sought under this Section 5.15, (whether or not the Indemnified Person is an actual or potential party to such claim or action) unless such settlement, compromise or consent includes an unconditional release of the Indemnified Person from all liability arising out of such claim, action, suit or proceeding. The indemnification obligations of the Administrator under this Section 5.15 shall survive the termination of this Agreement and the resignation or removal of the Bond Trustee.

Section 5.16 Administrator's Liability. Except as otherwise provided herein, the Administrator assumes no liability other than to render or stand ready to render the services called for herein, and neither the Administrator nor any of its directors, officers, employees, subsidiaries or affiliates shall be responsible for any action of the Bond Issuer or any of the trustees, officers, employees, subsidiaries or affiliates of the Bond Issuer (other than the Administrator itself). The Administrator shall not be liable for nor shall it have any obligation with regard to any of the liabilities, whether direct or indirect, absolute or contingent of the Bond Issuer or any of the trustees, officers, employees, subsidiaries or affiliates of the Bond Issuer (other than the Administrator itself).

Section 5.17 Collateral Assignment to Bond Trustee. The Administrator hereby acknowledges and consents to the Grant of a security interest and collateral assignment by the Bond Issuer to the Bond Trustee for the benefit of the Bondholders and the Bond Trustee pursuant to the Bond Indenture of all of the Bond Issuer's rights hereunder.

Section 5.18 Rule 17g-5 Compliance. The Administrator agrees that any notice, report, request for satisfaction of the Rating Agency Condition, document or other information provided by the Administrator to any Rating Agency under this Agreement or any other Basic Document to which it is a party for the purposes of determining the initial credit rating of the Bonds or undertaking credit rating surveillance of the Bonds with any Rating Agency shall be provided, substantially concurrently, to the Servicer for posting on the 17g-5 Website.

IN WITNESS WHEREOF, the parties have caused this Administration Agreement to be duly executed and delivered under seal as of the day and year first above written.

UTILITY DEBT SECURITIZATION AUTHORITY,
as Bond Issuer

By: ______________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

LONG ISLAND LIGHTING COMPANY,
as Administrator

By: ______________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

**Attachment 3**

# INDENTURE

# BOND INDENTURE

Dated as of September 29, 2022

between

UTILITY DEBT SECURITIZATION AUTHORITY

as Bond Issuer

and

THE BANK OF NEW YORK MELLON,

as Bond Trustee

relating to

$935,655,000

RESTRUCTURING BONDS, SERIES 2022

TABLE OF CONTENTS

**ARTICLE V**
Remedies



**ARTICLE VI**
The Bond Trustee and Paying Agents



**ARTICLE VII**
The Bondholders

**ARTICLE VIII**
Accounts, Disbursements and Releases



**ARTICLE IX**
Supplemental Bond Indentures



**ARTICLE X**
Redemption of Bonds



**ARTICLE XI**
Miscellaneous

BOND INDENTURE, dated and effective as of September 29, 2022, between UTILITY DEBT SECURITIZATION AUTHORITY, a special purpose corporate municipal instrumentality, body corporate and politic, political subdivision and public benefit corporation of the State of New York (including any successor thereto, the “Bond Issuer”), and THE BANK OF NEW YORK MELLON, a New York banking corporation, in its capacity as bond trustee (including any successor thereto, the “Bond Trustee”).

## RECITALS

The Bond Issuer has duly authorized the execution and delivery of this Bond Indenture to provide for the issuance of its Bonds with an aggregate principal amount of $935,655,000 and the Bond Issuer and the Bond Trustee are executing and delivering this Bond Indenture in order to provide for the issuance of the Bonds.

The Bond Issuer has the power under clause (c)(xi) of subdivision 2 of Section 4 of the LIPA Reform Act, as security for the payment of the principal of and interest on any restructuring bonds issued by it pursuant to the LIPA Reform Act, and any agreement made in connection therewith, to pledge all or any part of its revenues or assets, including, without limitation, restructuring property, unspent proceeds of its restructuring bonds, transition charge revenues, and earnings from the investment and reinvestment of unspent proceeds of its restructuring bonds and transition charge revenues (as all of such terms are defined and/or used in the LIPA Reform Act).

## GRANTING CLAUSE

The Bond Issuer hereby Grants to the Bond Trustee at the Issuance Date, as Bond Trustee for the benefit of the Holders of the Bonds and the Bond Trustee, all of the Bond Issuer’s right, title and interest in and to (a) the Restructuring Property (created by Sections 5 and 7 of the LIPA Reform Act and Ordering Paragraph 11 of the Financing Order) transferred by the Seller to the Bond Issuer pursuant to the Sale Agreement and all proceeds thereof, including the Charges as estimated, determined and adjusted from time to time pursuant to the Servicing Agreement in accordance with the Financing Order, (b) the Statutory Lien, (c) the Sale Agreement, (d) the Servicing Agreement, (e) the Administration Agreement, (f) the Collection Account (including all Subaccounts thereof) and all amounts or investment property on deposit therein or credited thereto from time to time, (g) the security interest with respect to the Restructuring Property granted by the Seller to the Bond Issuer in the Sale Agreement, (h) all present and future claims, demands, causes and choses in action in respect of any or all of the foregoing and all payments on or under and all proceeds of every kind and nature whatsoever in respect of any or all of the foregoing, including all proceeds of the conversion thereof, voluntary or involuntary, into cash or other liquid property, all cash proceeds, accounts, accounts receivable, notes, drafts, acceptances, chattel paper, checks, deposit accounts, securities accounts, insurance proceeds, condemnation awards, rights to payment of any and every kind, and other forms of obligations and receivables, instruments and other property which at any time constitute all or part of or are included in the proceeds of any of the foregoing and (i) all proceeds of the foregoing (collectively, the “Collateral”); it being understood that the following do not constitute Collateral: (1) amounts required to be released pursuant to or contemplated by the terms hereof, (2) proceeds from the sale of the Bonds required to pay the purchase price of the Restructuring Property paid pursuant to the Sale Agreement and the costs of issuance with respect to the Bonds as deposited into the Upfront Financing Costs Subaccount (together with any interest earnings thereon) and (3) any restructuring property purchased by the Bond Issuer with the proceeds of the Bond Issuer’s Prior Restructuring Bonds or any restructuring property created pursuant to any financing order other than the Financing Order.

The foregoing Grants are made to the Bond Trustee in trust to secure the payment of principal of, interest on, and all other amounts owing in respect of, the Bonds, including all amounts payable to the Bond Trustee under this Bond Indenture and the other Basic Documents, equally and ratably without prejudice, priority or distinction, except as expressly provided in this Bond Indenture, and to secure compliance with the provisions of this Bond Indenture with respect to the Bonds, all as provided in this Bond Indenture (collectively, the "Secured Obligations").

The Bond Trustee, as trustee on behalf of the Holders of the Bonds and as agent for itself, acknowledges such Grants, accepts the trusts hereunder in accordance with the provisions hereof and agrees to perform its duties specifically required herein.

AND IT IS HEREBY COVENANTED, DECLARED AND AGREED between the parties hereto that all Bonds are to be issued, countersigned and delivered and that all of the Collateral is to be held and applied, subject to the further covenants, conditions, releases, uses and trusts hereinafter set forth, and the Bond Issuer, for itself and any successor, does hereby covenant and agree to and with the Bond Trustee and its successors in said trust, for the benefit of the Holders and the Bond Trustee, as follows:

# ARTICLE I

## Definitions and Incorporation by Reference

Section 1.01. Definitions.

Except as otherwise specified herein or as the context may otherwise require, the following terms have the respective meanings set forth below for all purposes of this Bond Indenture.

"<u>Act</u>" has the meaning specified in Section 7.01(a).

"<u>Administration Agreement</u>" means the Administration Agreement dated as of September __, 2022, between Long Island Lighting Company d/b/a LIPA, as Administrator, and the Bond Issuer, as the same may be amended and supplemented from time to time.

"<u>Administration Fee</u>" means the fee payable to the Administrator pursuant to the Administration Agreement.

"<u>Administrator</u>" means Long Island Lighting Company d/b/a LIPA, or any successor Administrator under the Administration Agreement.

"<u>Affiliate</u>" means, with respect to any specified Person, any other Person controlling or controlled by or under common control with such specified Person. For the purposes of this definition, "control" when used with respect to any specified Person means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "controlling" and "controlled" have meanings correlative to the foregoing.

"<u>Aggregate Scheduled Debt Service</u>" means, for any period and as of any date of calculation, an amount equal to the principal of and interest on any Outstanding Bonds scheduled to be payable during such period, in accordance with the Expected Amortization Schedule.

"<u>Authority</u>" means Long Island Power Authority, a corporate municipal instrumentality of the State of New York, and any successor thereto.

"Authorized Officer" means, with respect to the Bond Issuer, any officer of the Bond Issuer who is authorized to act for the Bond Issuer in matters relating to the Bond Issuer and who is identified on the list of Authorized Officers delivered by the Bond Issuer to the Bond Trustee on the Issuance Date (as such list may be modified or supplemented by the Bond Issuer from time to time thereafter).

"Basic Documents" means, collectively, this Bond Indenture, the Sale Agreement, the Servicing Agreement and the Administration Agreement.

"Bondholder" or "Holder" means the Person in whose name a Bond is registered on the Bond Register.

"Bond Indenture" or "this Bond Indenture" means this instrument as originally executed and, as from time to time supplemented or amended by one or more indentures supplemental hereto entered into pursuant to the applicable provisions hereof, as so supplemented or amended, or both, and shall include the forms and terms of the Bonds established hereunder.

"Bond Interest Rate" means, with respect to any Series and Tranche of Bonds, the Bond Interest Rate therefor as specified in Section 2.02.

"Bond Issuer" means the party named as such in this Bond Indenture until a successor replaces it and, thereafter, means the successor.

"Bond Purchase Agreement" means the Bond Purchase Agreement dated September 16, 2022, between the Bond Issuer and the underwriters named therein.

"Bond Register" and "Bond Registrar" have the respective meanings specified in Section 2.05.

"Bonds" has the meaning specified in Section 2.01.

"Bond Trustee" means The Bank of New York Mellon, as Bond Trustee under this Bond Indenture, or any successor Bond Trustee under this Bond Indenture.

"Book-Entry Bonds" means, with respect to any Bond, a beneficial interest in such Bond, ownership and transfers of which shall be made through book entries by a Clearing Agency as described in Section 2.16.

"Business Day" means any day other than a Saturday, a Sunday or a day on which banking institutions or trust companies in New York, New York, are authorized or obligated by law, regulation or executive order to remain closed.

"Clearing Agency" means an organization registered as a "clearing agency" pursuant to Section 17A of the Exchange Act.

"Clearing Agency Participant" means a broker, dealer, bank, other financial institution or other Person for whom from time to time a Clearing Agency effects book entry transfers and pledges of securities deposited with the Clearing Agency.

"Code" means the Internal Revenue Code of 1986, as amended from time to time, and the applicable regulations thereunder.

"Collateral" has the meaning specified in the Granting Clause of this Bond Indenture.

"Collection Account" has the meaning specified in Section 8.02(a).

"Corporate Trust Office" means the office of the Bond Trustee at which at any particular time this Bond Indenture shall be administered, which office at the date of the execution of this Bond Indenture is located at 101 Barclay Street, Floor 7 W, New York, New York 10286, Attention: Frederic Belen, Vice President, or at such other address as the Bond Trustee may designate from time to time by notice to the Bondholders and the Bond Issuer, or the principal corporate trust office of any successor Bond Trustee (the address of which the successor Bond Trustee will notify the Bondholders and the Bond Issuer).

"Debt Service Reserve Subaccount" has the meaning set forth in Section 8.02(a).

"Default" means any occurrence that is, or with notice or the lapse of time or both would become, an Event of Default.

"Defeasance Securities" mean direct obligations of, or obligations fully and unconditionally guaranteed as to timely payment by, the United States of America.

"Definitive Bonds" has the meaning set forth in Section 2.16(a).

"DTC" means The Depository Trust Company, as securities depository for the Bonds, or its successor or any successor securities depository.

"Eligible Account" means a segregated trust account with an Eligible Institution.

"Eligible Institution" means (a) the corporate trust department of the Bond Trustee so long as any securities of the Bond Trustee have either a short-term credit rating from Moody's of at least "P-1" or a long-term unsecured debt rating from Moody's of at least "A2" and have a credit rating from each other rating agency in one of its generic categories which either signifies either "A2" or "A-1" or higher by Standard & Poor's or "A" or "F1" or higher by Fitch; or (b) a depository institution organized under the laws of the United States of America, any State or the District of Columbia (or any domestic branch of a foreign bank), (i) which has either (A) a long-term issuer rating of "AA-" or higher by Standard & Poor's, "A2" or higher by Moody's, and "A" or higher by Fitch, or (B) a short-term issuer rating of "A-1+" or higher by Standard & Poor's, "P-1" or higher by Moody's, and, "F1" or higher by Fitch, or any other long-term, short-term or certificate of deposit rating acceptable to Standard & Poor's, Moody's and Fitch, and (ii) whose deposits are insured by the FDIC. If so qualified under clause (b) above, the Bond Trustee may be considered an Eligible Institution for the purposes of the definition of Eligible Account.

"Eligible Investments" mean instruments and investment property denominated in United States currency which meet the criteria described below:

(a) direct obligations of, or obligations fully and unconditionally guaranteed as to timely payment by, the United States of America;

(b) demand deposits, time deposits or certificates of deposit and bankers' acceptances of Eligible Institutions (including the Bond Trustee in its commercial capacity);

(c) commercial paper having, at the time of the investment or contractual commitment, a rating of not less than "A-1" from Standard & Poor's, not less than "P-1" by Moody's and not less than "F1" by Fitch (including commercial paper issued by the Bond Trustee);

(d) money market funds which have the highest rating from at least two of the Rating Agencies (including funds for which the Bond Trustee or any of its Affiliates is an investment manager or advisor);

(e) repurchase obligations with respect to any security that is a direct obligation of, or fully guaranteed by, the United States of America or certain of its agencies or instrumentalities, entered into with Eligible Institutions;

(f) repurchase obligations with respect to any security or whole loan entered into with an Eligible Institution or a registered broker-dealer, acting as principal and that meets certain ratings criteria set forth below:

(i) a broker/dealer (acting as principal) registered as a broker or dealer under Section 15 of the Exchange Act (any broker/dealer being referred to in this definition as a "broker/dealer"), the unsecured short-term debt obligations of which are rated at least "P-1" by Moody's, "A-1+" by Standard & Poor's and, if Fitch provides a rating thereon, "F-1+" by Fitch, and the long-term debt obligations of which are rated at least "Aa3" by Moody's, in each case at the time of entering into this repurchase obligation, or

(ii) an unrated broker/dealer acting as principal, that is a wholly-owned subsidiary of a non-bank or bank holding company the unsecured short-term debt obligations of which are rated at least "P-1" by Moody's, "A-1+" by Standard & Poor's and, if Fitch provides a rating thereon, "F-1+" by Fitch, and the long-term debt obligations of which are rated at least "Aa3" by Moody's, in each case at the time of purchase so long as the obligations of such unrated broker/dealer are unconditionally guaranteed by such non-bank or bank holding company; and

(g) any other investment described in an Issuer Order, upon the satisfaction of the Rating Agency Condition.

"Event of Default" has the meaning specified in Section 5.01.

"Excess Funds Subaccount" has the meaning specified in Section 8.02(a).

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Expected Amortization Schedule" means a schedule specifying for each Tranche the initial principal amount, Bond Interest Rate, Scheduled Maturity Date and Final Maturity Date, including the Expected Sinking Fund Schedule for Term Bonds and the matters specified in the definition thereof. The Expected Amortization Schedules for the Bonds are included in Section 2.02(b).

"Expected Sinking Fund Schedule" means a schedule specifying for any Term Bonds the Scheduled Sinking Fund Redemption Dates, Scheduled Outstanding Amounts, Scheduled Sinking Fund Payments and Minimum Remaining Outstanding Amounts. The Expected Sinking Fund Schedules for the Bonds that are Term Bonds are included in Section 2.02(e).

"FDIC" means the Federal Deposit Insurance Corporation or any successor.

"Final Maturity Date" means, with respect to any Tranche of Bonds, the respective Final Maturity Date therefor as specified in Section 2.02(b).

"Financing Cost" has the meaning specified in Section 2 of the LIPA Reform Act and consists of Upfront Financing Costs and Ongoing Financing Costs.

"Financing Order" means the Authority's Restructuring Cost Financing Order No. 6 approved and adopted May 18, 2022.

"Fitch" means Fitch Ratings, or its successor.

"General Subaccount" has the meaning set forth in Section 8.02(a).

"Grant" means mortgage, pledge, collaterally assign and grant a Lien upon and a security interest pursuant to this Bond Indenture. A Grant of the Collateral or of any other agreement or instrument shall include all rights, powers and options (but none of the obligations) of the Granting party thereunder, including the immediate and continuing right to claim for, collect, receive and give receipt for payments in respect of the Collateral and all other moneys payable thereunder, to give and receive notices and other communications, to make waivers or other agreements, to exercise all rights and options, to bring Proceedings in the name of the Granting party or otherwise and generally to do and receive anything that the Granting party is or may be entitled to do or receive thereunder or with respect thereto.

"Independent" means, when used with respect to any specified Person, that the Person (a) is in fact independent of the Bond Issuer, any other obligor upon the Bonds, the Seller, the Servicer and any Affiliate of any of the foregoing Persons, (b) does not have any direct financial interest or any material indirect financial interest in the Bond Issuer, any such other obligor, the Seller, the Servicer or any Affiliate of any of the foregoing Persons and (c) is not connected with the Bond Issuer, any such other obligor, the Seller, the Servicer or any Affiliate of any of the foregoing Persons as an officer, employee, promoter, underwriter, trustee, partner, director or person performing similar functions.

"Independent Certificate" means a certificate or opinion to be delivered to the Bond Trustee, made by an Independent appraiser or other expert appointed by an Issuer Order and consented to by the Bond Trustee, and such opinion or certificate shall state that the signer has read the definition of "Independent" in this Bond Indenture and that the signer is Independent within the meaning thereof.

"Issuance Date" has the meaning set forth in Section 2.02(g)(i).

"Issuer Order" and "Issuer Request" means a written order or request signed in the name of the Bond Issuer by any one of its Authorized Officers and delivered to the Bond Trustee.

"Legal Defeasance" has the meaning specified in Section 4.01(b).

"Lien" means a security interest, lien, mortgage, charge, pledge, claim, or encumbrance of any kind.

"LIPA Reform Act" means Part B of Chapter 173, Laws of New York, 2013, as amended to the date hereof.

"Minimum Denomination" means, with respect to the Series TE Bonds, $5,000 or any integral multiple thereof, and with respect to the Series T Bonds, $100,000 or integral multiples of $1,000 in excess thereof.

"Minimum Remaining Outstanding Amount" means, as of any Scheduled Sinking Fund Redemption Date and with respect to any Term Bond, the Minimum Remaining Outstanding Amount therefor as specified in the applicable Expected Sinking Fund Schedule set forth in Section 2.02(e).

"Moody's" means Moody's Investors Service Inc., or its successor.

"Officer's Certificate" means a certificate signed by any Authorized Officer of the Bond Issuer and delivered to the Bond Trustee.

"Ongoing Financing Costs" has the meaning specified in the LIPA Reform Act and the Financing Order.

"Operating Expenses" means all Ongoing Financing Costs other than principal (including amortization, sinking fund or redemption payments) and redemption premium, if any, and interest on the Bonds and amounts required to replenish each of the Subaccounts within the Reserve Subaccount.

"Operating Reserve Subaccount" has the meaning set forth in Section 8.02(a).

"Opinion of Counsel" means one or more written opinions of counsel who may, except as otherwise expressly provided in this Bond Indenture, be an employee of or counsel to the Bond Issuer and who shall be reasonably satisfactory to the Bond Trustee, and which opinion or opinions shall be addressed to the Bond Trustee, and shall be in form and substance reasonably satisfactory to the Bond Trustee.

"Outstanding" means, as of the date of determination, all Bonds theretofore authenticated and delivered under this Bond Indenture except:

(a) Bonds theretofore cancelled by the Bond Registrar or delivered to the Bond Registrar for cancellation;

(b) Bonds or portions thereof the payment for which money in the necessary amount has been theretofore deposited with the Bond Trustee or any Paying Agent in trust for the Holders of such Bonds; and

(c) Bonds in exchange for or in lieu of other Bonds which have been authenticated and delivered pursuant to this Bond Indenture unless proof satisfactory to the Bond Trustee is presented that any such Bonds are held by a bona fide purchaser;

provided, however, that in determining whether the Holders of the requisite Outstanding Amount of the Bonds or any Series or Tranche thereof have given any request, demand, authorization, direction, notice, consent or waiver hereunder or under any Basic Document, Bonds owned by the Bond Issuer, the Seller or any Affiliate of any of the foregoing Persons shall be disregarded and deemed not to be Outstanding, except that, in determining whether the Bond Trustee shall be protected in relying upon any such request, demand, authorization, direction, notice, consent or waiver, only Bonds that the Bond Trustee actually knows to be so owned shall be so disregarded. Bonds so owned that have been pledged in good faith may be regarded as Outstanding if the pledgee establishes to the satisfaction of the Bond Trustee the pledgee's right so to act with respect to such Bonds and that the pledgee is not the Bond Issuer, any other obligor upon the Bonds, the Seller or any Affiliate of any of the foregoing Persons.

"Outstanding Amount" means the aggregate principal amount of all Bonds or, if the context requires, all Bonds of a Series or of a Tranche, Outstanding at the date of determination.

"PACB" means the New York Public Authorities Control Board and any successor thereto.

"Paying Agent" means the Bond Trustee or any other Person that meets the eligibility standards for the Bond Trustee specified in Section 6.11 and is authorized by the Bond Issuer to make payment of principal of or interest on the Bonds on behalf of the Bond Issuer.

"Payment Date" has the meaning specified in Section 2.02(g)(iii).

"Person" means any individual, corporation, limited liability company, estate, partnership, joint venture, association, joint stock company, trust (including any beneficiary thereof), unincorporated organization or government or any agency or political subdivision thereof.

"Predecessor Bond" means, with respect to any particular Bond, every previous Bond evidencing all or a portion of the same debt as that evidenced by such particular Bond; and, for the purpose of this definition, any Bond authenticated and delivered under Section 2.06 in lieu of a mutilated, lost, destroyed or stolen Bond shall be deemed to evidence the same debt as the mutilated, lost, destroyed or stolen Bond.

"Prior Restructuring Bonds" means, collectively, the Bond Issuer's Restructuring Bonds, Series 2013TE and Series 2013T, the Bond Issuer's Restructuring Bonds, Series 2015, the Bond Issuer's Restructuring Bonds, Series 2016A, the Bond Issuer's Restructuring Bonds, Series 2016B and the Bond Issuer's Restructuring Bonds, Series 2017.

"Proceeding" means any suit in equity, action at law or other judicial or administrative proceeding.

"Projected Principal Balance" means, as of any Payment Date for any Tranche of the Bonds, the initial principal amount of such Tranche for such Payment Date as set forth in the Expected Amortization Schedule.

"Rating Agency" means, collectively, Moody's, Standard & Poor's and Fitch. If no such organization or successor is any longer in existence, "Rating Agency" shall be a nationally recognized statistical rating organization or other comparable Person designated by the Bond Issuer, notice of which designation shall be given to the Bond Trustee and the Servicer.

"Rating Agency Condition" means, with respect to any action, not less than ten (10) Business Days' prior written notification to each Rating Agency of such action, and written confirmation from each of Standard & Poor's and Moody's to the Servicer, the Bond Trustee and the Bond Issuer that such action will not result in a suspension, reduction or withdrawal of the then current rating by such Rating Agency of any Series or Tranche of Bonds and that prior to the taking of the proposed action no other Rating Agency shall have provided written notice to the Bond Issuer that such action has resulted or would result in the suspension, reduction or withdrawal of the then current rating of any Series or Tranche of Bonds; provided, however, that if within such ten (10) Business Day period, any Rating Agency (other than Standard & Poor's) has neither replied to such notification nor responded in a manner that indicates that such Rating Agency is reviewing and considering the notification, then (i) the Bond Issuer shall be required to confirm that such Rating Agency has received the Rating Agency Condition request, and if it has, promptly request the related Rating Agency Condition confirmation and (ii) if the Rating Agency neither replies to such notification nor responds in a manner that indicates it is reviewing and considering the notification within five (5) Business Days following such second request, the applicable Rating Agency Condition requirement shall not be deemed to apply to such Rating Agency. For the purposes of this definition, any confirmation, request, acknowledgment or approval that is required to be in writing may be in the form of electronic mail or a press release (which may contain a general waiver of a Rating Agency's right to review or consent).

"Record Date" means, with respect to a Payment Date, the close of business on the Business Day next preceding such Payment Date; provided however, that if Definitive Bonds are issued, the Record Date shall mean the last Business Day of the calendar month immediately preceding such Payment Date**.**

"Redemption Price" means, with respect to any Bonds to be redeemed, the principal amount of such Bonds or percentage thereof specified for such redemption in Section 2.02.

"Registered Holder" means the Person in whose name a Bond is registered on the Bond Register on the applicable Record Date.

"Required Debt Service Reserve Level" means, (a) as of any date of calculation occurring on or prior to November 15, 2022, an amount equal to the greater of (i) the amount of Semiannual Interest due on the December 15, 2022, Payment Date plus 0.5% of the aggregate principal amount of Bonds then outstanding minus the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation and (ii) $0, and (b) as of any date of calculation occurring after November 15, 2022, an amount equal to the greater of (i) 0.5]% of the aggregate principal amount of Bonds then outstanding minus the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation and (ii) $0. For the avoidance of doubt, to the extent that no principal amount is shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to a date of calculation, the minimum principal amount of Bonds shown as being expected to be paid on the Expected Amortization Schedule on any Payment Date subsequent to such date of calculation for purposes of calculating the Required Debt Service Reserve Level will be $0.

"Required Operating Reserve Level" means, as of any date of calculation, an amount equal to 0.50% of the aggregate principal amount of the Bonds originally issued; provided, however, that if any Bonds are refunded in advance of their maturity as permitted by Section 2.02(f), on and after the date that provision for the payment of the Bonds so refunded has been made pursuant to Section 4.02 hereof the Required Operating Reserve Level shall be equal to 0.50% of the Outstanding Amount of the Bonds immediately after such date.

"Required Reserve Level" means, as of any date of calculation, the sum of the Required Debt Service Reserve Level and the Required Operating Reserve Level.

"Reserve Subaccount" has the meaning set forth in Section 8.02(a).

"Responsible Officer" means, with respect to the Bond Trustee, any officer assigned to the Corporate Trust Office, including any Vice President, Assistant Vice President, Secretary, Assistant Secretary, Treasurer or Assistant Treasurer or any other officer of the Bond Trustee customarily performing functions similar to those performed by any of the above designated officers, in each case having direct responsibility for the administration of this Bond Indenture.

"Sale Agreement" means the Restructuring Property Purchase and Sale Agreement dated as of September 29, 2022, between the Bond Issuer and the Seller, as the same may be amended and supplemented from time to time.

"Scheduled Maturity Date" means, with respect to any Serial Bonds, the Scheduled Maturity Date therefor as specified in the Expected Amortization Schedule set forth in Section 2.02(b).

"Scheduled Sinking Fund Payment" means, with respect to any Term Bonds, the Scheduled Sinking Fund Payment therefor as specified in the Expected Sinking Fund Schedule set forth in Section 2.02(e).

"Scheduled Sinking Fund Redemption Date" means, with respect to any Term Bonds, the Scheduled Sinking Fund Redemption Date therefor as specified in the Expected Sinking Fund Schedule set forth in Section 2.02(e).

"Securities Act" means the Securities Act of 1933, as amended.

"Securities Intermediary" means The Bank of New York Mellon, a New York banking corporation, solely in its capacity as a "securities intermediary" as defined in Section 8-102(a)(14) of the UCC, or any successor securities intermediary.

"Seller" means Long Island Power Authority.

"Semiannual Interest" has the meaning specified in Section 2.02(g)(iv).

"Semiannual Principal" means, with respect to any Payment Date and any Series and Tranche of Bonds, (i) for any Serial Bonds, the amount required to be paid to the Holders pursuant to Section 2.02(d), and (ii) for any Term Bonds, the amount required to be redeemed and paid to the Holders pursuant to Section 2.02(e).

"Serial Bonds" means Bonds which are not Term Bonds.

"Series" or "Series of Bonds" or "Bonds of a Series" means all Bonds designated as being of the same series issued and delivered on original issuance in a simultaneous transaction, and any Bonds thereafter delivered in lieu thereof or in substitution therefor pursuant to this Bond Indenture.

"Series TE Bonds" means, collectively, the Series TE-1 Bonds and the Series TE-2 Bonds.

"Series TE-1 Bonds" means the Bonds designated "Series TE-1 Bonds" authorized by Section 2.01 and Section 2.02(a).

"Series TE-2 Bonds" means the Bonds designated "Series TE-2 Bonds" authorized by Section 2.01 and Section 2.02(a).

"Series T Bonds" means the Bonds designated "Series T Bonds" authorized by Section 2.01 and Section 2.02(a).

"Servicer" means Long Island Lighting Company d/b/a LIPA as Servicer under the Servicing Agreement, which may contract with others for the performance of some duties under the Servicing Agreement.

"Servicing Agreement" means the Restructuring Property Servicing Agreement dated as of September 29, 2022, between the Bond Issuer and Long Island Lighting Company d/b/a LIPA, as Servicer, as the same may be amended and supplemented from time to time in accordance with Section 7.01 thereof.

"Sinking Fund Payment" means a payment upon redemption of Term Bonds on a Payment Date as specified in the Expected Sinking Fund Schedule applicable thereto, or with respect to any Tranche a payment without redemption prior to maturity that reduces the Outstanding Amount thereof to zero.

"Standard & Poor's" means Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc., or its successor.

"State" means any one of the states of the United States of America or the District of Columbia.

"State Pledge" has the meaning specified in Section 2.13.

"Statutory Lien" means the Lien on the Restructuring Property created by subdivision 2 of Section 7 of the LIPA Reform Act and the Financing Order in the Restructuring Property Granted and pledged by this Bond Indenture.

"Subaccounts" means, collectively, the General Subaccount, the Excess Funds Subaccount, the Reserve Subaccount (which consists of the Operating Reserve Subaccount and the Debt Service Reserve Subaccount) and the Upfront Financing Costs Subaccount in the Collection Account.

"Successor Servicer" has the meaning specified in Section 3.05(d).

"Term Bonds" means Bonds the retirement of which shall be provided for from scheduled periodic redemptions prior to maturity.

"Tranche" or "Tranche of Bonds" or "Bonds of a Tranche" or of a particular Series means all Bonds designated as being of the same Series and tranche issued and delivered on original issuance in a simultaneous transaction, and any Bonds thereafter delivered in lieu thereof or in substitution therefor pursuant to this Bond Indenture.

"Trust Indenture Act" means the Trust Indenture Act of 1939 as in force on the date hereof, unless otherwise specifically provided.

"UCC" means, unless the context otherwise requires, the Uniform Commercial Code, as in effect in the State of New York, as amended from time to time.

"Underwriters" means the underwriters who purchase the Bonds from the Bond Issuer and sell the Bonds pursuant to the Bond Purchase Agreement.

"Upfront Financing Costs Subaccount" has the meaning set forth in Section 8.02(a).

"Upfront Financing Costs" has the meaning specified in the LIPA Reform Act and the Financing Order.

"U.S. Government Obligations" means direct obligations (or certificates representing an ownership interest in such obligations) of the United States of America (including any agency or instrumentality thereof) for the payment of which the full faith and credit of the United States of America is pledged.

"17g-5 Website" has the meaning specified in Section 11.15.

Except as otherwise specified herein or as the context may otherwise require, the following terms have the respective meanings set forth in Appendix A to the Servicing Agreement as in effect on the

Issuance Date for all purposes of this Bond Indenture, and the definitions of such terms are equally applicable both to the singular and plural forms of such terms:

Adjustment Notice
Allocation Agent
Annual Accountant's Report
Charges
Excess Remittance
Financing Order
Issuance Advice Letter
LIPA
Principal Balance
Restructuring Property
Seller
Semiannual Servicer Certificate
Servicer
Servicer Default
Servicing Fee
True-Up Adjustment

Section 1.02. Rules of Construction.

Unless the context otherwise requires:

(a) a term has the meaning assigned to it;

(b) an accounting term not otherwise defined has the meaning assigned to it in accordance with generally accepted accounting principles as in effect from time to time;

(c) "or" is not exclusive;

(d) "including" means including without limitation;

(e) words in the singular include the plural and words in the plural include the singular;

(f) words of the masculine gender shall mean and include correlative words of the feminine and neuter genders;

(g) words importing persons shall include firms, associations, partnerships (including limited partnerships), trusts, corporations and other legal entities, including public bodies, as well as natural persons, and shall include successors and assigns;

(h) each time of day shall be local time in The City of New York, New York, except as otherwise specified herein;

(i) each reference to Bonds includes portions thereof in Authorized Denominations;

(j) the words "herein," "hereof," "hereunder" and other words of similar import refer to this Bond Indenture as a whole and not to any particular Article, Section or other subdivision;

(k) all references in this Bond Indenture to designated “Articles,” “Sections” and other subdivisions are to the designated Articles, Sections and other subdivisions of this Bond Indenture; and

(l) except as otherwise specified herein, UCC terms shall have the meanings given to such terms in the UCC.

## ARTICLE II
The Bonds

Section 2.01. Authorization of Bonds.

There are hereby authorized to be issued pursuant to and for the purposes specified in the LIPA Reform Act and the Financing Order an issue of restructuring bonds (as defined in the LIPA Reform Act) designated as “Restructuring Bonds, Series 2022” and as further designated below (the “Bonds”).

Section 2.02. Terms of the Series TE-1 Bonds, Series TE-2 and Series T Bonds.

(a) *Authorization; Designation.* The issuance of three Series of Bonds in an aggregate initial principal amount of $935,655,000 is hereby authorized, which Bonds shall be designated as the “Restructuring Bonds” and further designated as “Series TE-1”, “Series TE-2” and “Series T”.

(b) *Initial Principal Amounts; Bond Interest Rates; Scheduled Maturity Dates; Final Maturity Dates*. The Series TE-1 Bonds shall be issued in twenty-five (25) separate tranches, the Series TE-2 Bonds shall be issued in seven (7) separate tranches and the Series T Bonds shall be issued in three (3) separate tranches. The Series TE-1 Bonds and the Series TE-2 Bonds (collectively referred to as the “Series TE Bonds”) shall constitute Bonds the interest on which is exempt from federal income taxes. The Series T Bonds shall constitute Bonds the interest on which is not exempt from federal income taxes. Within each such Series, Bonds of a Tranche with a specified Final Maturity Date shall be designated by reference to its Final Maturity Date. The Series TE-1 Bonds, Series TE-2 Bonds and Series T Bonds shall be issued in the aggregate initial principal amount of $787,290,000, $94,780,000 and $53,585,000, respectively, and shall bear interest at the rates per annum and have initial principal amounts, Scheduled Maturity Dates and Final Maturity Dates as set forth below:

**$53,585,000**
**UTILITY DEBT SECURITIZATION AUTHORITY**
**RESTRUCTURING BONDS, SERIES 2022T (FEDERALLY TAXABLE)**

| Tranche | Initial Principal Amount | Scheduled Maturity Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|
| Tranche 1 | $20,945,000 | 12/15/2023 | 12/15/2025 | 4.421% |
| Tranche 2 | $11,650,000 | 12/15/2029 | 12/15/2031 | 4.653% |
| Tranche 3 | $20,990,000 | 12/15/2037 | 12/15/2039 | 4.953% |

**$787,290,000**
**UTILITY DEBT SECURITIZATION AUTHORITY**
**RESTRUCTURING BONDS, SERIES 2022TE-1 (FEDERALLY TAX-EXEMPT)**

| Tranche | Initial Principal Amount | Scheduled Maturity Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|
| Tranche 1 | $5,955,000 | 6/15/2023 | 6/15/2025 | 5.000% |
| Tranche 2 | $6,100,000 | 12/15/2023 | 12/15/2025 | 5.000% |
| Tranche 3 | $6,055,000 | 6/15/2024 | 6/15/2026 | 5.000% |
| Tranche 4 | $6,205,000 | 12/15/2024 | 12/15/2026 | 5.000% |
| Tranche 5 | $12,010,000 | 6/15/2025 | 6/15/2027 | 5.000% |
| Tranche 6 | $12,300,000 | 12/15/2025 | 12/15/2027 | 5.000% |
| Tranche 7 | $49,330,000 | 6/15/2026 | 6/15/2028 | 5.000% |
| Tranche 8 | $50,560,000 | 12/15/2026 | 12/15/2028 | 5.000% |
| Tranche 9 | $67,560,000 | 6/15/2027 | 6/15/2029 | 5.000% |

| | | | | |
|---|---|---|---|---|
| Tranche 10 | $69,250,000 | 12/15/2027 | 12/15/2029 | 5.000% |
| Tranche 11 | $38,975,000 | 6/15/2028 | 6/15/2030 | 5.000% |
| Tranche 12 | $39,950,000 | 12/15/2028 | 12/15/2030 | 5.000% |
| Tranche 13 | $49,690,000 | 6/15/2029 | 6/15/2031 | 5.000% |
| Tranche 14 | $50,930,000 | 12/15/2029 | 12/15/2031 | 5.000% |
| Tranche 15 | $30,740,000 | 6/15/2030 | 6/15/2032 | 5.000% |
| Tranche 16 | $31,500,000 | 12/15/2030 | 12/15/2032 | 5.000% |
| Tranche 17 | $17,090,000 | 6/15/2031 | 6/15/2033 | 5.000% |
| Tranche 18 | $17,515,000 | 12/15/2031 | 12/15/2033 | 5.000% |
| Tranche 19 | $17,765,000 | 6/15/2032 | 6/15/2034 | 5.000% |
| Tranche 20 | $18,205,000 | 12/15/2032 | 12/15/2034 | 5.000% |
| Tranche 21 | $26,590,000 | 12/15/2033 | 12/15/2035 | 5.000% |
| Tranche 22 | $5,490,000 | 12/15/2034 | 12/15/2036 | 5.000% |
| Tranche 23 | $900,000 | 12/15/2035 | 12/15/2037 | 5.000% |
| Tranche 24 | $93,930,000 | 12/15/2036 | 12/15/2038 | 5.000% |
| Tranche 25 | $62,695,000 | 12/15/2037 | 12/15/2039 | 5.000% |

**$94,780,000**
**UTILITY DEBT SECURITIZATION AUTHORITY**
**RESTRUCTURING BONDS, SERIES 2022TE-2 (FEDERALLY TAX-EXEMPT) (GREEN BONDS)**

| Tranche | Initial Principal Amount | Scheduled Maturity Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|
| Tranche 1 | $5,330,000 | 12/15/2038 | 12/15/2040 | 5.000% |
| Tranche 2 | $5,600,000 | 12/15/2039 | 12/15/2041 | 5.000% |
| Tranche 3 | $5,885,000 | 12/15/2040 | 12/15/2042 | 5.000% |
| Tranche 4 | $6,180,000 | 12/15/2041 | 12/15/2043 | 5.000% |
| Tranche 5 | $6,490,000 | 12/15/2042 | 12/15/2044 | 5.000% |
| Tranche 6 | $37,745,000 | 12/15/2047 | 12/15/2049 | 5.000% |
| Tranche 7 | $27,550,000 | 12/15/2050 | 9/15/2052 | 5.000% |

(c) *General Priority of Payment of Principal.* Unless an Event of Default shall have occurred and be continuing and the unpaid principal amount of all Bonds and accrued interest thereon has been declared to be immediately due and payable, or except as to Bonds of a Tranche that may be redeemed pursuant to any optional redemption provisions applicable to such Bonds, no payment of the principal on any Tranche of Series TE Bonds or Series T Bonds of any Final Maturity Date shall be made on any Payment Date prior to the payment in full of all of the principal of all Tranches of Series TE Bonds and Series T Bonds with an earlier Final Maturity Date and no principal payments on any Tranche of Bonds shall be made on any Payment Date until interest due on all Bonds on such Payment Date is paid in full. Partial payments of any scheduled payment shall be allocated within the Bonds of a particular tranche pro rata. Partial payments (if any) of any amortization payments shall be allocated between Tranches of Series TE Bonds and Series T Bonds with the same Final Maturity Date pro rata.

(d) *Serial Bond Payments of Principal.* The Series TE-1-1 Bonds through Series TE-1-20 Bonds shall be Serial Bonds. Unless an Event of Default shall have occurred and be continuing and the unpaid principal amount of all Bonds and accrued interest thereon has been declared to be immediately due and payable, or except as to Series TE Bonds of a Tranche that may be redeemed pursuant to any optional redemption provisions applicable to such Series TE Bonds, on each Payment Date, the Bond Trustee shall pay to the Registered Holders of such Serial Bonds amounts payable pursuant to Section 8.02(e) as principal, until the Outstanding Amount of such Serial Bonds has been reduced to zero; provided, however, that no principal payment shall be made on a Serial Bond pursuant to this Section 2.02(d) prior to the Scheduled Maturity Date for that Serial Bond.

(e) *Term Bond Payments of Principal.* The Series TE–1-21 through Series TE–1-25 Bonds, the Series TE–2-1 through Series TE–2-7 Bonds and the Series T–1 through Series T–3 Bonds shall constitute Term Bonds and shall be subject to redemption from time to time as hereinafter provided at a Redemption Price of 100% of the principal amount of such respective Term Bonds to be redeemed, together with accrued interest to the redemption date. Unless an Event of Default shall have occurred and be continuing and the unpaid principal amount of all Bonds and accrued interest thereon has been declared to be due and payable, or except as to Bonds that may be redeemed pursuant to any optional redemption provisions applicable to such Bonds, on each Scheduled Sinking Fund Redemption Date, the Bond Trustee shall redeem the respective Term Bonds prior to maturity and pay to the Registered Holders of such Bonds amounts payable pursuant to Section 8.02(e) as a Sinking Fund Payment until the Outstanding Amount of the respective Term Bonds has been reduced to zero; provided, however, that any payment that reduces the Outstanding Amount to zero shall be applied as a payment of a maturity of the respective Term Bonds and not as a redemption prior to maturity; provided further, however, that no Sinking Fund Payment shall be made pursuant to this Section 2.02(e) prior to the respective first Scheduled Sinking Fund Redemption Date and on any Payment Date in an amount that reduces the Outstanding Amount of the respective Term Bonds below the Minimum Remaining Outstanding Amount specified in the Expected Sinking Fund Schedule below; and provided further, however, that any Term Bonds presented to the Bond Trustee for cancellation on or before forty-five (45) days prior to a Payment Date shall reduce the amount to be redeemed on such Payment Date by a like principal amount.

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2023 | $20,945,000 | $10,360,000 | $10,585,000 |
| 12/15/2023 | $10,585,000 | $10,585,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2029 | $11,650,000 | $5,760,000 | $5,890,000 |
| 12/15/2029 | $5,890,000 | $5,890,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022T TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $20,990,000 | $10,365,000 | $10,625,000 |
| 12/15/2037 | $10,625,000 | $10,625,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 21**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2033 | $26,590,000 | $13,130,000 | $13,460,000 |
| 12/15/2033 | $13,460,000 | $13,460,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 22**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2034 | $5,490,000 | $2,710,000 | $2,780,000 |
| 12/15/2034 | $2,780,000 | $2,780,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 23**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2035 | $900,000 | $445,000 | $455,000 |
| 12/15/2035 | $455,000 | $455,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1 TRANCHE 24**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2036 | $93,930,000 | $46,385,000 | $47,545,000 |
| 12/15/2036 | $47,545,000 | $47,545,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-1**
**TRANCHE 25**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2037 | $62,695,000 | $30,960,000 | $31,735,000 |
| 12/15/2037 | $31,735,000 | $31,735,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 1**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2038 | $5,330,000 | $2,630,000 | $2,700,000 |
| 12/15/2038 | $2,700,000 | $2,700,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 2**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2039 | $5,600,000 | $2,765,000 | $2,835,000 |
| 12/15/2039 | $2,835,000 | $2,835,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 3**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2040 | $5,885,000 | $2,905,000 | $2,980,000 |
| 12/15/2040 | $2,980,000 | $2,980,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 4**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2041 | $6,180,000 | $3,050,000 | $3,130,000 |
| 12/15/2041 | $3,130,000 | $3,130,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 5**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2042 | $6,490,000 | $3,205,000 | $3,285,000 |
| 12/15/2042 | $3,285,000 | $3,285,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 6**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2043 | $37,745,000 | $3,370,000 | $34,375,000 |
| 12/15/2043 | $34,375,000 | $3,455,000 | $30,920,000 |
| 6/15/2044 | $30,920,000 | $3,540,000 | $27,380,000 |
| 12/15/2044 | $27,380,000 | $3,630,000 | $23,750,000 |
| 6/15/2045 | $23,750,000 | $3,720,000 | $20,030,000 |
| 12/15/2045 | $20,030,000 | $3,810,000 | $16,220,000 |
| 6/15/2046 | $16,220,000 | $3,905,000 | $12,315,000 |
| 12/15/2046 | $12,315,000 | $4,005,000 | $8,310,000 |
| 6/15/2047 | $8,310,000 | $4,105,000 | $4,205,000 |
| 12/15/2047 | $4,205,000 | $4,205,000 | $0 |

**EXPECTED SINKING FUND SCHEDULE –2022TE-2**
**TRANCHE 7**

| Scheduled Sinking Fund Redemption Date | Scheduled Outstanding Amount | Scheduled Sinking Fund Payment | Minimum Remaining Outstanding Amount |
|---|---|---|---|
| 6/15/2048 | $27,550,000 | $4,315,000 | $23,235,000 |
| 12/15/2048 | $23,235,000 | $4,420,000 | $18,815,000 |
| 6/15/2049 | $18,815,000 | $4,530,000 | $14,285,000 |
| 12/15/2049 | $14,285,000 | $4,645,000 | $9,640,000 |
| 6/15/2050 | $9,640,000 | $4,760,000 | $4,880,000 |
| 12/15/2050 | $4,880,000 | $4,880,000 | $0 |

(f) *Optional Redemption.* (i) The Series TE Bonds with a Final Maturity Date on or prior to December 15, 2034 are not subject to optional redemption prior to maturity at the option of the Bond Issuer. The Series TE Bonds with a Final Maturity Date on or after December 15, 2035 are subject to redemption at the option of the Bond Issuer in whole or in part, in any order, from time to time on any Business Day on and after December 15, 2032 upon payment of the redemption price of 100% of the principal amount of the Series TE Bonds to be redeemed, together with accrued interest to the redemption date.

(ii) Notwithstanding any priority of payment set forth in this Bond Indenture or any other limitations as to the redemption of Series T Bonds, the Series T Bonds are subject to redemption at the option of the Issuer in whole or in part, in any order, from time to time on any Business Day, at a redemption price equal to the greater of:

(1) 100% of the principal amount of the Series T Bonds to be redeemed; or

(2) the sum of the present value of the remaining scheduled payments of principal of and interest on the Series T Bonds of such maturity to be redeemed, not including any portion of those payments of interest accrued and unpaid as of the date on which the Series T Bonds are to be redeemed, discounted on a semi-annual basis to the date on which the Series T Bonds of such maturity are to be redeemed, assuming a 360-day year containing twelve 30-day months, at the Treasury Rate, (i) plus 10 basis points (0.10%) for Tranche 1 of the Series T Bonds (ii) plus 20 basis points (0.20%) for Tranche 2 of the Series T Bonds, and (iii) plus 25 basis points (0.25%) for Tranche 3 of the Series T Bonds;

plus, in each case, accrued and unpaid interest on such Series T Bonds to be redeemed to but not including the redemption date.

For the purpose of any optional redemption of the Series T Bonds as described above,

"Treasury Rate" means, with respect to any redemption date of any maturity of the Series T Bonds of a particular maturity, the rate per annum, expressed as a percentage of the principal amount, equal to the semi-annual equivalent yield to maturity or yield to theoretical maturity (calculated in such case as the linear interpolation between the yields of two U.S. Treasury securities) of the Comparable Treasury Issue, assuming that the Comparable Treasury Issue is purchased on the redemption date for a price equal to the Comparable Treasury Price, as calculated by the Designated Investment Banker.

"Comparable Treasury Issue" means, with respect to any redemption date for a Series T Bond of a particular maturity, the United States Treasury security or securities selected by the Designated Investment Banker that has an actual or theoretical maturity comparable to the remaining average life of the Series T Bond of the maturity to be redeemed, and that would be utilized in accordance with customary financial practice in pricing new issues of debt securities of comparable maturity to the remaining average life of the Series T Bond to be redeemed. For purposes of determining the Comparable Treasury Issue for a theoretical maturity, the U.S. Treasury securities to be utilized in the calculation of the Treasury Rate shall be (1) an actively traded U.S. Treasury security or U.S. Treasury Index whose maturity is closest to but no later than the date corresponding to the remaining average life of the Series T Bonds to be redeemed, and (2) an actively traded U.S. Treasury security or U.S. Treasury Index whose maturity is closest to but no earlier than the date corresponding to the remaining average life of the Series T Bonds to be redeemed.

"Comparable Treasury Price" means, with respect to any redemption date for a Series T Bond of a particular maturity.

The Trustee shall not be responsible for calculating the redemption price of the Series T Bonds. At the option of the Authority, the redemption price of the Series T Bonds to be redeemed may be determined by an independent accounting firm, investment banking firm, financial advisor, municipal advisor or other financial consultant retained by the Authority. The Trustee and the Authority may conclusively rely on the determination of such redemption price by such independent accounting firm, investment banking firm, financial advisor, municipal advisor or other financial consultant and shall not be liable for such reliance.

(g) *Authentication Date; Registered Form and Denominations; Semiannual Interest; Computation of Interest.*

(i) Authentication Date. The Bonds that are authenticated and delivered by the Bond Trustee to or upon the order of the Bond Issuer on September 29, 2022 (the "Issuance Date") shall have as their date of authentication September 29, 2022.

(ii) Registered Form and Denominations. The Series TE and Series T Bonds shall be issued in fully registered form without coupons and in not less than Minimum Denominations.

(iii) Payment Dates. The Payment Dates for the Series TE and Series T Bonds shall be June 15 and December 15 of each year and the Final Maturity Date of such bonds, or, if any such date is not a Business Day, the next succeeding Business Day, commencing on December 15, 2023 and continuing until the earlier of repayment of the Series TE and Series T Bonds in full or the respective Final Maturity Date.

(iv) Semiannual Interest. Semiannual Interest will be payable on each Tranche of Series TE and Series T Bonds on each Payment Date in an amount equal to one-half of the product of (A) the applicable Bond Interest Rate and (B) the Outstanding Amount of the related Tranche of such Bonds as of the close of business on the preceding Payment Date after giving effect to all payments of principal made to the Holders of the related Tranche of such Bonds on such preceding Payment Date; provided, however that with respect to the initial Payment Date or, if no payment has yet been made, interest on the outstanding principal balance will accrue from and including the Issuance Date to but excluding that Payment Date.

(v) Interest Rate Computation. Bond Interest Rates shall be computed on the basis of a 360-day year of twelve 30-day months.

Section 2.03. Form.

The Bonds and the Bond Trustee's certificate of authentication shall be in substantially the forms set forth in Exhibit A, with such appropriate insertions, omissions, substitutions and other variations as are required or permitted by this Bond Indenture and may have such letters, numbers or other marks of identification and such legends or endorsements placed thereon as may, consistently herewith, be determined by the officers executing such Bonds, as evidenced by their execution of such Bonds.

The Bonds shall be typewritten, printed, lithographed or engraved or produced by any combination of these methods (with or without steel engraved borders), all as determined by the officers executing such Bonds, as evidenced by their execution of such Bonds.

Pursuant to recommendations promulgated by the Committee on Uniform Security Identification Procedures, "CUSIP" numbers may be printed on the Bonds. The Bonds may bear such endorsement or legend satisfactory to the Bond Trustee as may be required to conform to usage or law with respect thereto.

Unless otherwise directed by the Bond Issuer, the Bonds of each Series shall be numbered from R-1 upward, unless otherwise determined by the Bond Trustee and approved by the Bond Issuer.

The terms of the Bonds set forth in Exhibit A are part of the terms of this Bond Indenture.

The Bonds shall contain a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of New York is pledged to the payment of the principal of, or interest on, this Bond."

Section 2.04. Execution, Authentication and Delivery.

The Bonds shall be executed on behalf of the Bond Issuer by any of its Authorized Officers. The signature of any such Authorized Officer on the Bonds may be manual or facsimile.

Bonds bearing the manual or facsimile signature of individuals who were at any time Authorized Officers of the Bond Issuer shall bind the Bond Issuer, notwithstanding that such individuals or any of them have ceased to hold such offices prior to the authentication and delivery of such Bonds or did not hold such offices at the date of such Bonds.

At any time and from time to time after the execution and delivery of this Bond Indenture, the Bond Issuer may deliver Bonds executed by the Bond Issuer to the Bond Trustee pursuant to an Issuer Order for authentication; and the Bond Trustee shall authenticate and deliver such Bonds as provided in this Bond Indenture and not otherwise.

No Bond shall be entitled to any benefit under this Bond Indenture or be valid or obligatory for any purpose, unless there appears on such Bond a certificate of authentication substantially in the form provided for herein, executed by the Bond Trustee by the manual signature of one of its authorized signatories, and such certificate upon any Bond shall be conclusive evidence, and the only evidence, that such Bond has been duly authenticated and delivered hereunder.

Section 2.05. Registration; Registration of Transfer and Exchange.

The Bond Issuer shall cause to be kept a register (the "Bond Register") in which, subject to such reasonable regulations as it may prescribe, the Bond Issuer shall provide for the registration of Bonds and the registration of transfers and exchanges of Bonds. The Bond Issuer shall cause the Bond Registrar to designate, by a written notification to the Bond Trustee, a specific office location (which may be changed from time to time, upon similar notification) at which the Bond Register is kept.

The Bond Trustee shall be the "Bond Registrar" for the purpose of registering Bonds and transfers of Bonds as herein provided. Upon any resignation of any Bond Registrar, the Bond Issuer shall promptly appoint a successor or, if it elects not to make such an appointment, assume the duties of Bond Registrar. Any Person other than the Bond Trustee undertaking to act as Bond Registrar shall first execute a written agreement, in form satisfactory to the Bond Trustee, to perform the duties of a Bond Registrar under this Bond Indenture, which agreement shall be filed with the Bond Trustee.

If a Person other than the Bond Trustee is appointed by the Bond Issuer as Bond Registrar, the Bond Issuer will give the Bond Trustee prompt written notice of the appointment of such Bond Registrar and of the location, and any change in the location, of the Bond Register, and the Bond Trustee shall have the right to inspect the Bond Register at all reasonable times and to obtain copies thereof, and the Bond Trustee shall have the right to rely upon a certificate executed on behalf of the Bond Registrar by a Responsible Officer thereof as to the names and addresses of the Holders of the Bonds and the principal amounts and number of such Bonds.

Upon surrender for registration of transfer of any Bond at the office or agency of the Bond Issuer to be maintained as provided in Section 3.02, the Bond Issuer shall execute, and the Bond Trustee shall authenticate and the Bondholder shall obtain from the Bond Trustee, in the name of the designated transferee or transferees, one or more new Bonds in any Minimum Denominations, of a like Series and Tranche and aggregate principal amount; provided, however, if any such surrendered Bond shall have become or within 15 days shall be due and payable, instead of issuing a replacement Bond, the Bond Trustee may pay such surrendered Bond when so due and payable without surrender thereof.

At the option of the Holder, Bonds may be exchanged for other Bonds in any Minimum Denominations, of a like Series and Tranche and aggregate principal amount, upon surrender of the Bonds to be exchanged at the designated office of the Bond Registrar or its agent. Whenever any Bonds are so surrendered for exchange, the Bond Issuer shall execute, and the Bond Trustee shall authenticate and the Bondholder shall obtain from the Bond Trustee, the Bonds which the Bondholder making the exchange is entitled to receive.

All Bonds issued upon any registration of transfer or exchange of Bonds shall be the valid obligations of the Bond Issuer, evidencing the same debt, and entitled to the same benefits under this Bond Indenture, as the Bonds surrendered upon such registration of transfer or exchange.

Every Bond presented or surrendered for registration of transfer or exchange shall be duly endorsed by, or be accompanied by (a) a written instrument of transfer in form satisfactory to the Bond Trustee duly executed by the Holder thereof or such Holder's attorney duly authorized in writing, with such signature guaranteed by an institution which is a member of one of the following recognized Signature Guaranty Programs: (i) The Securities Transfer Agent Medallion Program (STAMP); (ii) The New York Stock Exchange Medallion Program (MSP); (iii) The Stock Exchange Medallion Program

(SEMP); or (iv) in such other guarantee program acceptable to the Bond Trustee, and (b) such other documents as the Bond Trustee may require.

No service charge shall be made to a Holder for any registration of transfer or exchange of Bonds, but the Bond Issuer may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any registration of transfer or exchange of Bonds.

The preceding provisions of this Section notwithstanding, the Bond Issuer shall not be required to make and the Bond Registrar need not register transfers or exchanges of any Bond during the period from and including the Record Date for any payment with respect to the Bond to and excluding such payment date.

Section 2.06. Mutilated, Destroyed, Lost or Stolen Bonds.

If (i) any mutilated Bond is surrendered to the Bond Trustee, or the Bond Trustee receives evidence to its satisfaction of the destruction, loss or theft of any Bond, and (ii) there is delivered to the Bond Trustee such security or indemnity as may be required by it to hold the Bond Issuer and the Bond Trustee harmless, then, in the absence of notice to the Bond Issuer, the Bond Registrar or the Bond Trustee that such Bond has been acquired by a protected purchaser, the Bond Issuer shall execute and, upon its request, the Bond Trustee shall authenticate and deliver, in exchange for or in lieu of any such mutilated, destroyed, lost or stolen Bond, a replacement Bond of like Series, Tranche, tenor and principal amount, bearing a number not contemporaneously outstanding; provided, however, that if any such destroyed, lost or stolen Bond, but not a mutilated Bond, shall have become or within seven (7) days shall be due and payable, instead of issuing a replacement Bond, the Bond Issuer may pay such destroyed, lost or stolen Bond when so due or payable, without surrender thereof. If, after the delivery of such replacement Bond or payment of a destroyed, lost or stolen Bond pursuant to the proviso to the preceding sentence, a protected purchaser of the original Bond in lieu of which such replacement Bond was issued presents for payment such original Bond, the Bond Issuer and the Bond Trustee shall be entitled to recover such replacement Bond (or such payment) from the Person to whom it was delivered or any Person taking such replacement Bond from such Person to whom such replacement Bond was delivered or any assignee of such Person, except a protected purchaser, and shall be entitled to recover upon the security or indemnity provided therefor to the extent of any loss, damage, cost or expense incurred by the Bond Issuer or the Bond Trustee in connection therewith.

Upon the issuance of any replacement Bond under this Section, the Bond Issuer may require the payment by the Holder of such Bond of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto and any other reasonable expenses (including the fees and expenses of the Bond Trustee) connected therewith.

Every replacement Bond issued pursuant to this Section in replacement of any mutilated, destroyed, lost or stolen Bond shall constitute an original additional contractual obligation of the Bond Issuer, whether or not the mutilated, destroyed, lost or stolen Bond shall be at any time enforceable by anyone, and shall be entitled to all the benefits of this Bond Indenture equally and proportionately with any and all other Bonds duly issued hereunder.

The provisions of this Section are exclusive and shall preclude (to the extent lawful) all other rights and remedies with respect to the replacement or payment of mutilated, destroyed, lost or stolen Bonds.

Section 2.07. Persons Deemed Owner.

Prior to due presentment for registration of transfer of any Bond, the Bond Issuer, the Bond Trustee and any agent of the Bond Issuer or the Bond Trustee may treat the Person in whose name any Bond is registered (as of the day of determination) as the owner of such Bond for the purpose of receiving payments of principal of and interest on such Bond and for all other purposes whatsoever, whether or not such Bond be overdue, and neither the Bond Issuer, the Bond Trustee nor any agent of the Bond Issuer or the Bond Trustee shall be affected by notice to the contrary.

Section 2.08. Payment of Principal and Interest; Interest on Overdue Principal; Principal and Interest Rights Preserved.

(a) Any installment of interest or principal payable on any Bond which is punctually paid or duly provided for by the Bond Issuer on the applicable Payment Date shall be paid to the Person in whose name such Bond (or one or more Predecessor Bonds) is registered on the Record Date for such Payment Date, by check mailed first-class, postage prepaid to such Person's address as it appears on the Bond Register on such Record Date; provided, however, that (i) upon application to the Bond Trustee by any Holder owning Bonds of any single Tranche (*i.e.*, not in the aggregate among all such Tranches or Series) in the principal amount of $10,000,000 or more not later than the applicable Record Date, payment will be made by wire transfer to an account maintained by such Holder and (ii) with respect to Book-Entry Bonds, payments will be made by wire transfer in immediately available funds to the account designated by the Holder of the applicable Bond and as required by the operational rules and procedures of the Clearing Agency unless and until such Bond is exchanged for Definitive Bonds (in which event payments shall be made as provided above) and except for the final installment of principal payable with respect to such Bond on a Payment Date, which shall be payable as provided below. The funds represented by any such checks returned undelivered shall be held in accordance with Section 3.03.

(b) The principal of each Bond of each Tranche shall be paid, to the extent funds are available therefor in the Collection Account, in installments on each Payment Date. Notwithstanding the foregoing, installments of principal not paid or redeemed when scheduled to be paid or redeemed in accordance with the Expected Amortization Schedule or Expected Sinking Fund Schedule shall be paid or redeemed upon receipt of money available for such purpose, on the next Payment Date, to the Registered Holder on the applicable Record Date, in the order set forth in the Expected Amortization Schedule or Expected Sinking Fund Schedule, as the case may be, subject to the general priority of payment of principal set forth in Section 2.02(c) and subject to prior redemption as provided in Section 2.02(f). Subject to the provisions below, failure to pay principal or, with respect to Bonds constituting Term Bonds, Redemption Price in accordance with such Expected Amortization Schedule or Expected Sinking Fund Schedule, as the case may be, because money is not available pursuant to Section 8.02 to make such payments shall not constitute an Event of Default under this Bond Indenture; provided, however, that failure to pay the entire unpaid principal amount of the Bonds of a Tranche upon the Final Maturity Date of the Tranche shall constitute an Event of Default, and the entire unpaid principal amount of the Bonds shall be due and payable, if not previously paid, on any other date on which an Event of Default shall have occurred and be continuing, if the Bond Trustee or the Holders of the Bonds representing not less than a majority of the Outstanding Amount of the Bonds have declared the Bonds to be immediately due and payable in the manner provided in Section 5.02. All payments of principal on the Bonds shall be made *pro rata* to the Holders entitled thereto unless otherwise provided herein with respect to any Tranche. The Bond Trustee shall notify the Person in whose name a Bond is registered at the close of business on the Record Date preceding the Payment Date on which the Bond Issuer expects that the final installment of principal of and interest on such Bond will be paid. Such notice shall be mailed by first class mail, postage prepaid, no later than five (5) days prior to such final Payment Date and shall specify that such final installment will be payable only upon presentation and surrender of such Bond and shall specify the place where such Bond may be presented and surrendered for payment of such installment.

(c) If the Bond Issuer defaults in a payment of interest on the Bonds when due, the Bond Issuer shall be required to pay such defaulted interest (plus interest on such defaulted interest at the applicable Bond Interest Rate to the extent lawful) to the Persons who are Bondholders on a subsequent special record date, which date shall be at least five (5) Business Days prior to the payment date. The Bond Issuer shall fix or cause to be fixed any such special record date and payment date, and, at least 20 days before any such special record date, the Bond Trustee shall mail to each affected Bondholder, by first class mail, postage prepaid, a notice that states the special record date, the payment date and the amount of defaulted interest (plus interest on such defaulted interest) to be paid.

Section 2.09. Cancellation.

All Bonds surrendered for payment, registration of transfer or exchange shall, if surrendered to any Person other than the Bond Trustee, be delivered to the Bond Trustee and shall be promptly cancelled by the Bond Trustee. The Bond Issuer may at any time deliver to the Bond Trustee for cancellation any Bonds previously authenticated and delivered hereunder which the Bond Issuer may have acquired in any manner whatsoever, and all Bonds so delivered shall be promptly cancelled by the Bond Trustee. No Bonds shall be authenticated in lieu of or in exchange for any Bonds cancelled as provided in this Section, except as expressly permitted by this Bond Indenture. All cancelled Bonds may be held or disposed of by the Bond Trustee in accordance with its standard retention or disposal policy as in effect at the time.

Section 2.10. Authentication and Delivery of Bonds.

On the Issuance Date, the Bonds shall be executed by the Bond Issuer and delivered to the Bond Trustee for authentication and thereupon the same shall be authenticated and delivered by the Bond Trustee upon Issuer Request and upon receipt by the Bond Trustee (or other satisfaction) of the following upon which the Bond Trustee may conclusively rely to the extent permitted to so rely under Article VI hereof:

(a) Bond Issuer Action; Application of Proceeds of Bonds and Other Moneys. An Issuer Order authorizing and directing the Bond Trustee to authenticate and deliver the Bonds, each to be registered in the name of Cede & Co., as nominee of DTC, and to confirm its custody of the Bonds to DTC in New York, New York, so that the Bonds may be credited to or upon the order of the Underwriters named in said order for the purchase price specified therein and directing the application of the proceeds thereof, which application shall be solely for the purposes of (i) purchasing Restructuring Property from the Seller, (ii) depositing into the Debt Service Reserve Subaccount cash in an amount equal to the Required Debt Service Reserve Level, and (iii) paying or providing for the payment of Upfront Financing Costs, provided that (A) Upfront Financing Costs may be paid from Bond proceeds directly, as specified in such Issuer Order, and (B) any proceeds not required for Upfront Financings Costs may be used for Ongoing Financing Costs. The Bond Trustee shall establish a temporary segregated trust account in the Bond Trustee's name, apart from the Collateral Account, for the deposit of all or any portion of the proceeds of the Bonds to be applied for the purpose of purchasing Restructuring Property and for the application of such proceeds to such purpose as directed by such Issuer Order. Cash provided by the Authority in an amount equal to the Required Operating Reserve Level shall be deposited in the Operating Reserve Subaccount.

(b) Authorizations. An Opinion of Counsel that any authorization by, registration with, consent of, or approval by, any governmental agency, board, or commission that is necessary for the execution, delivery and issuance by the Bond Issuer of the Bonds, and the execution and delivery by the Bond Issuer of the Bond Indenture and the other Basic Documents, has been obtained.

(c) Authorizing Certificate. A certificate of an Authorized Officer of the Bond Issuer certifying that the Bond Issuer has duly authorized the execution and delivery of this Bond Indenture and the execution, authentication and delivery of the Bonds.

(d) Certificates of the Bond Issuer and the Seller.

(i) An Officer's Certificate from the Bond Issuer, dated as of the Issuance Date:

(A) to the effect that the Bond Issuer is not in Default under this Bond Indenture and that the issuance of the Bonds applied for will not result in any Default or in any breach of any of the terms, conditions or provisions of or constitute a default under any material indenture, mortgage, deed of trust or other agreement or instrument to which the Bond Issuer is a party or by which it or its property is bound or any order of any court or administrative agency entered in any Proceeding to which the Bond Issuer is a party or by which it or its property may be bound or to which it or its property may be subject that would have a material adverse effect on the Bonds; and that all conditions precedent provided in this Bond Indenture relating to the authentication and delivery of the Bonds have been complied with;

(B) to the effect that all instruments furnished to the Bond Trustee pursuant to this Bond Indenture conform to the requirements set forth in this Bond Indenture and constitute all of the documents required to be delivered hereunder for the Bond Trustee to authenticate and deliver the Bonds applied for, and all conditions precedent provided for in this Bond Indenture relating to the authentication and delivery of the Bonds have been complied with;

(C) to the effect that the Bond Issuer has not assigned any interest or participation in the Collateral except for the Lien of this Bond Indenture and of the LIPA Reform Act; the Bond Issuer has the power and right to Grant the Collateral to the Bond Trustee as security hereunder; and the Bond Issuer, subject to the terms of this Bond Indenture, has Granted to the Bond Trustee all of its right, title and interest in and to such Collateral free and clear of any Lien, mortgage, pledge, charge, security interest, adverse claim or other encumbrance, except the Lien of this Bond Indenture and of the LIPA Reform Act;

(D) to the effect that the Bond Issuer has appointed a firm of Independent certified public accountants as contemplated in Section 8.06; and

(E) to the effect that attached thereto are duly executed, true and complete copies of the Sale Agreement and the Servicing Agreement that have not been further amended or supplemented.

(ii) An Officer's Certificate (as defined in the Sale Agreement) from the Seller, dated as of the Issuance Date, to the effect that (A) the representations and warranties set forth in Article III of the Sale Agreement are true and correct and (B) the attached copy of the Financing Order creating the Restructuring Property and Issuance Advice Letter are true and correct and have not been further amended or supplemented.

(e) Opinion of Counsel. An Opinion of Counsel, portions of which may be delivered by counsel for the Bond Issuer, by counsel for the Seller and the Servicer, or by other counsel satisfactory to the Bond Trustee, dated the Issuance Date, in each case subject to customary exceptions, qualifications and assumptions contained therein (and upon which the Bond Trustee shall be entitled to rely), to the collective effect that:

(i) the Bond Issuer is duly organized and is validly existing as a special purpose corporate municipal instrumentality, constituting a body corporate and politic, political subdivision and public benefit corporation of the State of New York and has the power and authority to execute and deliver this Bond Indenture and the other Basic Documents and to issue the Bonds;

(ii) this Bond Indenture has been duly authorized, executed and delivered by the Bond Issuer and is a valid and binding agreement of the Bond Issuer, enforceable in accordance with its terms, except as such enforceability may be subject to bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer and other laws relating to or affecting the rights of creditors generally, whether theretofore or thereafter enacted, and general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law), including that the availability of specific performance or injunctive relief is subject to the discretion of the court before which any such proceeding is brought;

(iii) the Bonds have been duly authorized and executed and, when authenticated in accordance with the provisions of the Bond Indenture and delivered against payment of the purchase price therefor, will constitute valid and binding obligations of the Bond Issuer, entitled to the benefits of the Bond Indenture subject to bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer and other laws relating to or affecting the rights of creditors generally, whether theretofore or thereafter enacted, and general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law), including that the availability of specific performance or injunctive relief is subject to the discretion of the court before which any such proceeding is brought;

(iv) (A) by operation of subdivision 2 of Section 7 of the LIPA Reform Act, the provisions of this Bond Indenture create a first priority Statutory Lien on the Collateral in favor of the Bond Trustee for the benefit of the Bondholders, and (B) the Statutory Lien is valid, perfected and enforceable against the Bond Issuer and all third parties without any further public notice;

(v) the Bonds are exempt from the registration requirements under the Securities Act;

(vi) the Bond Issuer is not an "investment company" or under the "control" of an "investment company" as such terms are defined under the Investment Company Act of 1940, as amended, or is exempt pursuant to Section 2(b) thereof;

(vii) the Sale Agreement and the Servicing Agreement are valid and binding agreements of the Bond Issuer, enforceable in accordance with their respective terms, except as such enforceability may be subject to bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer and other laws relating to or affecting the rights of creditors generally, whether theretofore or thereafter enacted, and general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law) including that the availability of specific performance or injunctive relief is subject to the discretion of the court before which any such proceeding is brought;

(viii) the sale of the Restructuring Property by the Seller to the Bond Issuer pursuant to the Sale Agreement constitutes an absolute transfer of all of the Authority's right, title and interest (as in a true sale), and not as a pledge or other financing, of the Restructuring Property, other than for federal, state and local income and franchise tax purposes; and

(ix) (A) the Financing Order has been duly authorized and issued by the Authority in accordance with all applicable State of New York laws, rules and regulations, including the LIPA Reform Act; (B) the Financing Order and the process by which it was issued comply with all applicable State of New York laws, rules and regulations, including the LIPA Reform Act; (C) the Financing Order is in full force and effect and is final and not appealable; (D) as of the issuance of the Bonds, the Bonds are entitled to the protections provided under the LIPA Reform Act and the Financing Order, and the Holders of the Bonds shall be, to the extent permitted by the State of New York and federal law and this Bond Indenture, entitled to enforce the protections of the LIPA Reform Act and the Financing Order; and (E) the Servicer is authorized to file True-Up Adjustments to the Charge to the extent necessary to ensure the timely recovery of revenues sufficient to provide for the payment of all principal and interest on the Bonds and all other approved Financing Costs.

(f) Accountant's Letter. Such letter or letters of a firm of Independent certified public accountants of recognized national reputation as may be required by the Bond Purchase Agreement.

(g) Reserve Subaccount. The deposit into the Operating Reserve Subaccount of cash in an amount equal to the Required Operating Reserve Level and the deposit into the Debt Service Reserve Subaccount of cash in an amount equal to the Required Debt Service Reserve Level.

(h) Upfront Financing Costs Subaccount. The deposit into the Upfront Financing Costs Subaccount of cash in an amount equal to the Upfront Financing Costs specified in the Issuance Advice Letter.

(i) Other Requirements. Such other documents, certificates, agreements, instruments or opinions as may be required by the Bond Issuer in its discretion or as the Bond Trustee may reasonably require.

(j) Satisfaction of Conditions. Payment of the purchase price for the Bonds by the Underwriters in accordance with the Bond Purchase Agreement shall constitute satisfaction of the conditions set forth in this Section 2.10.

Section 2.11. Release of Collateral.

The Bond Trustee shall release property from the Lien of this Bond Indenture only as specified in Section 8.04.

Section 2.12. Tax Withholding.

Amounts properly withheld under the Code or other tax laws by any Person from a payment to any Holder of interest or principal shall be considered as having been paid by the Bond Issuer to such Holder for all purposes of this Bond Indenture.

Section 2.13. State Pledge.

Section 9(a) of the LIPA Reform Act (the "State Pledge") provides as follows and, as authorized by Section 9(b) of the LIPA Reform Act, is included in this Bond Indenture as a part hereof:

> "The state pledges to and agrees with the holders of restructuring bonds, any assignee, and all financing entities that the state will not in any way take or permit any action that limits, alters or impairs the value of restructuring property or, except as required by the adjustment mechanism described in the restructuring cost financing order, reduce, alter or impair transition charges that are imposed, collected and remitted for the benefit of the owners of restructuring bonds, any assignee, and all financing entities, until any principal, interest and redemption premium in respect of restructuring bonds, all ongoing financing costs and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid or performed in full."

The Bond Issuer hereby acknowledges that the purchase of any Bond by a Holder or the purchase of any beneficial interest in a Bond by any Person and the Bond Trustee's obligations to perform hereunder are made in reliance on such agreement and pledge by the State of New York. The Bond Issuer hereby represents and warrants to the Bond Trustee, for the benefit of the Bondholders, that it constitutes an "assignee" under Section 2 of the LIPA Reform Act and a "restructuring bond issuer" under subdivision 10 of Section 2 of the LIPA Reform Act, that the Bonds constitute "restructuring bonds" under subdivision 3 of Section 2 of the LIPA Reform Act, that the Bonds are entitled to the protections provided in subdivisions 4 and 5 of Section 5 and Section 9 of the LIPA Reform Act, and that the Holder of the Bonds shall be, to the extent permitted by state and federal law and this Bond Indenture, entitled to enforce such sections of the LIPA Reform Act.

Section 2.14. Security Interest.

The Bond Issuer hereby makes the following representations and warranties. Other than the Lien of this Bond Indenture, the Bond Issuer has not pledged, granted, sold, conveyed or otherwise assigned any interest or security interest in the Collateral. The Lien of this Bond Indenture constitutes a pledge of Restructuring Property and proceeds thereof in accordance with and pursuant to clause (c)(xi) of subdivision 2 of Section 4 of the LIPA Reform Act, subdivision 2 of Section 7 of the LIPA Reform Act and the Financing Order, and is perfected, valid and binding. The proceeds, moneys or revenues so pledged and hereafter received by the Bond Issuer as the owner of Restructuring Property shall immediately be subject to the lien of such pledge, and such lien is perfected, without any physical delivery thereof or further act. The lien of any such pledge is perfected, valid and binding as against all parties having claims of any kind in tort, contract or otherwise against the owner of Restructuring Property irrespective of whether such parties have notice thereof and shall be superior to any judicial liens or other liens obtained by such claimants or transferees. Pursuant to the LIPA Reform Act, no instrument by which such pledge or lien is created need be recorded in order to perfect such pledge or lien. Pursuant to the LIPA Reform Act, the pledge of Restructuring Property is a continuously perfected security interest and has priority over any other lien, created by operation of law or otherwise, that may subsequently attach to that Restructuring Property or proceeds thereof. The Holders, and the Bond Trustee on their behalf, have a perfected security interest in the amount of all Restructuring Property revenues or other proceeds that are deposited in any deposit account or other account of the Servicer or other entity in which Restructuring Property revenues or other proceeds have been commingled with other funds, subject to payments of Excess Remittances from the Collection Account pursuant to Section 3.03(c) of the Servicing Agreement and Section 8.02(e) and releases of Collateral permitted by Section 8.04. Any other security interest that may apply to Restructuring Property revenues or other proceeds shall be terminated when such revenues or proceeds are transferred to the Collection Account for an assignee or a financing party. No application of the adjustment mechanism as described in the LIPA Reform Act, the Financing

Order or the Servicing Agreement shall affect the validity, perfection, or priority of a pledge of, security interest in or the sale or transfer of Restructuring Property.

Notwithstanding the foregoing, the Bond Issuer shall file any initial financing statements, and the Bond Trustee hereby agrees to file any necessary continuation statements, which in the case of Restructuring Property shall be for informational purposes only describing the pledge and referring to the Financing Order and the Restructuring Property described therein under Article 9 of the UCC, as required by subdivision 2 of Section 7 of the LIPA Reform Act.

Section 2.15. Limitation of Liability for Payments.

All payments or distributions made to Holders of Bonds under this Bond Indenture, of Operating Expenses and of any expenses of the Bond Issuer to be paid or incurred that are not specifically denominated an Operating Expense shall be made only from the Collateral and only to the extent that the Bond Trustee shall have sufficient income or proceeds from the Collateral to make such payments in accordance with the terms of Article VIII of this Bond Indenture. Except as otherwise provided in this Bond Indenture, each Holder of a Bond, by acceptance of such Bond, agrees that it will look solely to the income and proceeds from the Collateral to the extent available for payment and distribution to such Holder as provided in this Bond Indenture.

The Bonds shall not constitute a debt, general obligation or a pledge of the faith and credit or taxing power of the State of New York or of any county, municipality or any other political subdivision, agency or instrumentality of the State of New York, other than the Bond Issuer. The issuance of the Bonds does not obligate the State of New York or any county, municipality or any other political subdivision, agency or instrumentality of the State of New York to levy any tax or make any appropriation for payment of the principal of or interest on the Bonds.

Section 2.16. Book-Entry and Definitive Bonds.

(a) The Bonds may be issued in the form of one or more typewritten certificates representing Book-Entry Bonds, to be delivered to The Depository Trust Company, the initial Clearing Agency, by, or on behalf of, the Bond Issuer. In such case, the Bonds delivered to The Depository Trust Company shall initially be registered on the Bond Register in the name of Cede & Co., the nominee of the initial Clearing Agency, and no Bondholder will receive a definitive Bond representing such Bondholder's interest in the Bonds, except as provided in Section 2.16(f). Unless and until definitive, fully registered Bonds ("Definitive Bonds") have been issued pursuant to Section 2.16(f):

(i) the provisions of this Section 2.16(a) shall be in full force and effect with respect to the Bonds;

(ii) the Bond Issuer, the Paying Agent, the Bond Registrar and the Bond Trustee may deal with the Clearing Agency for all purposes (including without limitation the making of payments and distributions on the Bonds and giving notices of redemption) as the authorized representative of the Bondholders and in accordance with the Clearing Agency's rules and procedures;

(iii) to the extent that the provisions of this Section 2.16 conflict with any other provisions of this Bond Indenture, the provisions of this Section 2.16 shall control;

(iv) the rights of Bondholders shall be exercised only through the Clearing Agency and shall be limited to those established by law and agreements between such Bondholders and the Clearing Agency Participants; and until Definitive Bonds are issued pursuant to Section 2.16(e), the Clearing Agency will make book-entry transfers among the Clearing Agency Participants and receive and transmit payments and distributions of principal of and interest on the Bonds to such Clearing Agency Participants; and

(v) whenever this Bond Indenture requires or permits actions to be taken based upon instructions or directions of Bondholders holding Bonds representing a specified percentage of the aggregate Outstanding Amount of Bonds, the Clearing Agency shall be deemed to represent such percentage only to the extent that it has received instructions to such effect from Bondholders or Clearing Agency Participants owning or representing, respectively, Bonds representing such percentage of the aggregate Outstanding Amount of Bonds, and has delivered such instructions to the Bond Trustee; the Bond Trustee shall have no obligation to determine whether the Clearing Agency has in fact received any such instructions.

(b) Whenever notice or other communication to the Holders of Bonds issued in the form of Book-Entry Bonds is required under this Bond Indenture, unless and until Definitive Bonds shall have been issued pursuant to Section 2.16(e), the Bond Trustee shall give all such notices and communications specified herein to be given to Holders of Bonds to the Clearing Agency.

(c) Except in the case of payment upon maturity or redemption if the book-entry system is not in effect, any provision of this Bond Indenture permitting or requiring the delivery of Bonds shall, while the book-entry system is in effect, be satisfied by the notation on the books of the Clearing Agency, of the transfer of the beneficial owner’s interest in such Bond.

(d) With respect to Bonds registered in the name of a Clearing Agency (or its nominee) neither the Bond Trustee nor the Bond Issuer shall have any obligation to any of its members or participants or to any Person on behalf of whom an interest is held in the Bonds.

(e) So long as the book-entry system is in effect, the Bond Trustee and Paying Agents shall comply with the terms of all agreements with and operational requirements of DTC.

(f) If (i) a Clearing Agency advises the Bond Trustee in writing that a Clearing Agency is no longer willing or able to properly discharge its responsibilities with respect to the Bonds, and the Bond Trustee or the Bond Issuer is unable to locate a qualified successor, (ii) the Bond Issuer at its option advises the Bond Trustee in writing that it elects to terminate the book-entry system through a Clearing Agency with respect to the Bonds, subject to applicable policies of such Clearing Agency, or (iii) after the occurrence of an Event of Default, Bondholders representing beneficial interests aggregating at least a majority of the Outstanding Amount of the Bonds advise the Clearing Agency and the Bond Trustee in writing that the continuation of a book-entry system through the Clearing Agency is no longer in the best interests of the Bondholders, then the Clearing Agency shall notify all Bondholders and the Bond Trustee of the occurrence of any such event and of the availability of Definitive Bonds to Bondholders requesting the same. Upon surrender to the Bond Trustee of the typewritten certificate or certificates representing the Book-Entry Bonds by the Clearing Agency, accompanied by registration instructions, and upon written direction by the Bond Issuer and delivery to the Bond Trustee by the Bond Issuer of executed Definitive Bonds, the Bond Trustee shall authenticate such Definitive Bonds in accordance with the instructions of the Clearing Agency. None of the Bond Issuer, the Bond Registrar or the Bond Trustee shall be liable for any delay in delivery of such instructions and may conclusively rely on, and shall be fully protected in relying on, such instructions. Upon the issuance of Definitive Bonds, the Bond Trustee shall recognize the Holders of the Definitive Bonds as Bondholders.

Section 2.17. Reservation of Right to Issue Additional Bonds.

To the extent permitted by the laws of the State of New York, additional bonds, notes or other obligations may be issued or incurred by the Bond Issuer for any purpose and secured as provided by such laws of the State of New York, other than by the Collateral, provided that the Rating Agency Condition shall have been satisfied.

## ARTICLE III
Covenants

Section 3.01. Payment of Principal and Interest.

The Bond Issuer will duly and punctually pay the principal of and redemption premium, if any, and interest on the Bonds in accordance with the terms of the Bonds and this Bond Indenture.

Section 3.02. Maintenance of Agent for Registration of Exchanges and Transfers.

The Bond Issuer hereby appoints the Bond Trustee as its agent to receive all Bonds that are surrendered for registration of transfer or exchange. Such surrenders shall be received at the Corporate Trust Office of the Bond Trustee.

Section 3.03. Money for Payments To Be Held in Trust.

As provided in Section 8.02(a), all payments of amounts due and payable with respect to any Bonds that are to be made from amounts withdrawn from the Collection Account pursuant to Section 8.02(e) shall be made on behalf of the Bond Issuer by the Bond Trustee or by another Paying Agent, and no amounts so withdrawn from the Collection Account for payments of Bonds shall be paid over to the Bond Issuer except as provided in this Section 3.03 and Section 8.02.

The Bond Issuer will cause each Paying Agent other than the Bond Trustee to execute and deliver to the Bond Trustee an instrument in which such Paying Agent shall agree with the Bond Trustee (and if the Bond Trustee acts as Paying Agent, it hereby so agrees), subject to the provisions of this Section, that such Paying Agent will:

(a) hold all sums held by it for the payment of amounts due with respect to the Bonds in trust for the benefit of the Persons entitled thereto until such sums shall be paid to such Persons or otherwise disposed of as herein provided and pay such sums to such Persons as herein provided;

(b) give the Bond Trustee notice of any Default by the Bond Issuer of which it has actual knowledge in the making of any payment required to be made with respect to the Bonds;

(c) at any time during the continuance of any such Default, upon the written request of the Bond Trustee, forthwith pay to the Bond Trustee all sums so held in trust by such Paying Agent;

(d) immediately resign as a Paying Agent and forthwith pay to the Bond Trustee all sums held by it in trust for the payment of Bonds if at any time it ceases to meet the standards required to be met by a Paying Agent at the time of its appointment; and

(e) comply with all requirements of the Code with respect to the withholding from any payments made by it on any Bonds of any applicable withholding taxes imposed thereon and with respect to any applicable reporting requirements in connection therewith.

The Bond Issuer may at any time, for the purpose of obtaining the satisfaction and discharge of this Bond Indenture or for any other purpose, by Issuer Order direct any Paying Agent to pay to the Bond Trustee all sums held in trust by such Paying Agent, such sums to be held by the Bond Trustee upon the same trusts as those upon which the sums were held by such Paying Agent; and upon such payment by any Paying Agent to the Bond Trustee, such Paying Agent shall be released from all further liability with respect to such money.

Subject to applicable laws with respect to escheat of funds, any money held by the Bond Trustee or any Paying Agent in trust for the payment of any amount due with respect to the principal of or interest on any Bond and remaining unclaimed for two (2) years after such amount has become due and payable shall be discharged from such trust and be paid to the Bond Issuer on Issuer Request and, subject to Section 11.16, the Holder of such Bond shall thereafter, as an unsecured general creditor, look only to the Bond Issuer for payment thereof (but only to the extent of the amounts so paid to the Bond Issuer and forming a part of the Collateral), and all liability of the Bond Trustee or such Paying Agent with respect to such trust money shall thereupon cease; provided, however, that the Bond Trustee or such Paying Agent, before being required to make any such repayment, may at the expense of the Bond Issuer cause to be published once, in a newspaper published in the English language, customarily published on each Business Day and of general circulation in The City of New York, notice that such money remains unclaimed and that, after a date specified therein, which shall not be less than 30 days from the date of such publication, any unclaimed balance of such money then remaining will be repaid to the Bond Issuer. The Bond Trustee may also adopt and employ, at the expense of the Bond Issuer, any other reasonable means of notification of such repayment (including mailing notice of such repayment to Holders whose right to or interest in moneys due and payable but not claimed is determinable from the records of the Bond Trustee or of any Paying Agent, at the last address of record for each such Holder).

Section 3.04. Protection of Collateral.

The Bond Issuer will from time to time execute and deliver all such supplements and amendments hereto and except to the extent required to be made by the Seller or Servicer, make all such filings pursuant to the LIPA Reform Act or the Financing Order, instruments of further assurance and other instruments, and will take such other action necessary or advisable to:

(a) maintain or preserve the Lien and security interest (and the priority thereof) of this Bond Indenture or carry out more effectively the purposes hereof;

(b) perfect, publish notice of or protect the validity of any Grant made or to be made by this Bond Indenture;

(c) enforce any of the Collateral;

(d) preserve and defend title to the Collateral and the rights of the Bond Trustee and the Bondholders in such Collateral against the claims of all Persons and parties, including without limitation the challenge by any party to the validity or enforceability of the Financing Order, any Adjustment Notice or the Restructuring Property or any proceeding relating thereto and institute any action or proceeding necessary to compel performance by the PACB or the State of New York of any of its obligations or duties under the LIPA Reform Act, the Financing Order or any Adjustment Notice; or

(e) pay any and all taxes levied or assessed against all or any part of the Collateral.

The Bond Issuer hereby designates the Bond Trustee its agent and attorney-in-fact with authorization to execute and/or file on behalf of the Bond Issuer, except to the extent required to be filed or furnished by the Seller or Servicer, any filings pursuant to the Financing Order or other instrument required by the Bond Trustee pursuant to this Section, it being understood that the Bond Trustee shall have no such obligation.

Section 3.05. Performance of Obligations; Servicing; Certain Filings.

The Bond Issuer (i) will diligently pursue any and all actions to enforce its rights under each instrument or agreement included in the Collateral and (ii) will not take any action and will use its reasonable efforts not to permit any action to be taken by others that would release any Person from any of such Person's covenants or obligations under any such instrument or agreement or that would result in the amendment, hypothecation, subordination, termination or discharge of, or impair the validity or effectiveness of, any such instrument or agreement, except, in each case, as expressly permitted in this Bond Indenture, the Sale Agreement, the Servicing Agreement or such other instrument or agreement.

(a) The Bond Issuer may contract with other Persons to assist it in performing its duties under this Bond Indenture, and any performance of such duties by a Person identified to the Bond Trustee in an Officer's Certificate of the Bond Issuer shall be deemed to be action taken by the Bond Issuer. Initially, the Bond Issuer has contracted with the Administrator and the Servicer to assist the Bond Issuer in performing its duties under this Bond Indenture.

(b) The Bond Issuer will punctually perform and observe all of its obligations and agreements contained in this Bond Indenture, in the Basic Documents and in the instruments and agreements included in the Collateral, including filing or causing to be filed all filings pursuant to the LIPA Reform Act or the Financing Order required to be filed by it by the terms of this Bond Indenture, the Sale Agreement and the Servicing Agreement in accordance with and within the time periods provided for herein and therein. Except as otherwise expressly permitted therein, the Bond Issuer shall not waive, amend, modify, supplement or terminate any Basic Document or any provision thereof without the written consent of the Bond Trustee (which consent shall not be withheld if (i) the Bond Trustee shall have received an Officer's Certificate stating that such waiver, amendment, modification, supplement or termination shall not adversely affect in any material respect the interests of the Bondholders and (ii) the Rating Agency Condition shall have been satisfied with respect thereto) or the Holders of at least a majority of the Outstanding Amount of Bonds.

(c) If the Bond Issuer shall have knowledge of the occurrence of a Servicer Default under the Servicing Agreement, the Bond Issuer shall promptly give written notice thereof to the Bond Trustee and the Rating Agencies, and shall specify in such notice the action, if any, the Bond Issuer is taking with respect of such default. If a Servicer Default shall arise from the failure of the Servicer to perform any of its duties or obligations under the Servicing Agreement with respect to the Restructuring Property, including the Charge, the Bond Issuer shall take all reasonable steps available to it to remedy such failure.

(d) As promptly as possible after the giving of notice to the Servicer and the Bond Trustee of termination of the Servicer's rights and powers pursuant to Section 6.01 of the Servicing Agreement, the Bond Issuer, subject to certain conditions set forth in the Servicing Agreement, shall appoint a successor Servicer (the "Successor Servicer") with the Bond Trustee's prior written consent thereto (which consent shall not be unreasonably withheld and shall be given upon the written direction of Holders of not less than a majority of the Outstanding Amount of the Bonds), and such Successor Servicer shall accept its appointment by a written assumption in a form acceptable to the Bond Issuer and the Bond Trustee. If within 30 days after the delivery of the notice referred to above, the Bond Issuer shall not have obtained such a new Servicer, the Bond Trustee, at the expense of the Bond Issuer, may petition a court of competent jurisdiction to appoint a Successor Servicer. In connection with any such appointment, the Bond Issuer may make such arrangements for the compensation of such successor as it and such successor shall agree, subject to the limitations set forth below and in the Servicing Agreement, and in accordance and in compliance with Section 6.04 of the Servicing Agreement, the Bond Issuer shall enter into an agreement with such successor for the servicing of the Restructuring Property (such agreement to be in form and substance satisfactory to the Bond Trustee).

(e) Upon any termination of the Servicer's rights and powers pursuant to the Servicing Agreement, the Bond Trustee shall promptly notify the Bond Issuer, the Bondholders and the Rating Agencies. As soon as a Successor Servicer is appointed, the Bond Issuer shall notify the Bond Trustee, the Bondholders and the Rating Agencies of such appointment, specifying in such notice the name and address of such Successor Servicer.

(f) Without derogating from the absolute nature of the assignment granted to the Bond Trustee under this Bond Indenture or the rights of the Bond Trustee hereunder, the Bond Issuer agrees that it will not, without the prior written consent of the Bond Trustee or the Holders of at least a majority in Outstanding Amount of the Bonds, amend, modify, waive, supplement, terminate or surrender, or agree to any amendment, modification, supplement, termination, waiver or surrender of, the terms of any Collateral or the Basic Documents, or waive timely performance or observance of any material term by the Seller or the Servicer under the Sale Agreement or the Servicing Agreement, respectively; provided, however, that no such consent of the Bond Trustee or the Holders shall be required with respect to any agreements between the Servicer and others for the performance of duties under the Servicing Agreement as then in effect or for any amendment of the Servicing Agreement permitted by Section 7.01(c) thereof including, upon satisfaction of the Rating Agency Condition, to accommodate the issuance of bonds, notes or other obligations pursuant to Section 2.17. If any such amendment, modification, supplement or waiver shall be so consented to by the Bond Trustee or such Holders, the Bond Issuer agrees to execute and deliver, in its own name and at its own expense, such agreements, instruments, consents and other documents as shall be necessary or appropriate in the circumstances. The Bond Issuer agrees that no such amendment, modification, supplement or waiver shall adversely affect the rights of the Holders of the Bonds Outstanding at the time of any such amendment, modification, supplement or waiver, except as otherwise agreed to by the Holders in accordance with the Basic Documents.

Section 3.06. Negative Covenants.

So long as any Bonds are Outstanding, the Bond Issuer shall not:

(a) except as expressly permitted by this Bond Indenture, sell, transfer, exchange or otherwise Grant or dispose of any of, or assign any interest in, the Collateral, unless directed to do so by the Bond Trustee in accordance with Article V;

(b) claim any credit on, or make any deduction from the principal or interest payable in respect of, the Bonds (other than amounts properly withheld from such payments under the Code or other tax law) or assert any claim against any present or former Bondholder by reason of the payment of the taxes levied or assessed upon any part of the Collateral;

(c) voluntarily consent to the termination of its existence or its dissolution or liquidation in whole or in part;

(d) (i) permit the validity or effectiveness of this Bond Indenture to be impaired, or permit the Lien of this Bond Indenture to be amended, hypothecated, subordinated, terminated or discharged, or permit any Person to be released from any covenants or obligations with respect to the Bonds under this Bond Indenture except as may be expressly permitted hereby, (ii) permit any Lien, charge, excise, claim, security interest, mortgage or other encumbrance (other than the Lien of this Bond Indenture and the

Statutory Lien) to be created by the Bond Issuer on or extend to or otherwise arise upon or burden the Collateral or any part thereof or any interest therein or the proceeds thereof or (iii) subject to the Statutory Lien, permit the Lien of this Bond Indenture not to constitute a valid first priority security interest in the Collateral; or

(e) take any action which is subject to a Rating Agency Condition without satisfying the Rating Agency Condition.

Section 3.07. Servicer's Obligations.

The Bond Issuer shall enforce the Servicer's compliance with all of the Servicer's obligations under the Servicing Agreement to the extent material to the payment and security of the Bonds.

Section 3.08. No Borrowing.

The Bond Issuer shall not issue, incur, assume, guarantee or otherwise become liable, directly or indirectly, for any indebtedness except for the Bonds, except pursuant to Section 2.17.

Section 3.09. No Additional Bonds.

The Bond Issuer shall not issue any additional Bonds hereunder, except pursuant to Section 2.05 or 2.06. Additional bonds, notes or other obligations may be issued or incurred by the Bond Issuer secured other than by the Collateral, subject to the limitations set forth in Section 2.17.

Section 3.10. Guarantees, Loans, Advances and Other Liabilities.

Except as otherwise contemplated by the Sale Agreement, the Servicing Agreement or this Bond Indenture, the Bond Issuer shall not make any loan or advance or credit to, or guarantee (directly or indirectly or by an instrument having the effect of assuring another's payment or performance on any obligation or capability of so doing or otherwise), endorse or otherwise become contingently liable, directly or indirectly, in connection with the obligations, stocks or dividends of, or own, purchase, repurchase or acquire (or agree contingently to do so) any stock, obligations, assets or securities of, or any other interest in, or make any capital contribution to, any other Person.

Section 3.11. Capital Expenditures.

Other than expenditures in connection with the Bond Issuer's purchase of Restructuring Property from the Seller, the Bond Issuer shall not make any expenditure (by long-term or operating lease or otherwise) for capital assets (either realty or personalty).

Section 3.12. Notice of Events of Default.

The Bond Issuer agrees to give the Bond Trustee and the Rating Agencies prompt written notice of each Event of Default hereunder as provided in Section 5.01, or waiver thereof and each default on the part of the Seller or the Servicer of its obligations under the Sale Agreement or the Servicing Agreement, respectively, materially and adversely affecting the Bonds.

Section 3.13. Further Instruments and Acts.

Upon request of the Bond Trustee, the Bond Issuer will execute and deliver such further instruments and do such further acts as may be reasonably necessary or proper to carry out more effectively the purpose of this Bond Indenture and maintain a first priority perfected security interest in the Collateral in favor of the Bond Trustee.

Section 3.14. Tax Covenants.

The Bond Issuer covenants that with respect to the Series TE Bonds, the interest on which is intended to be excluded from gross income for federal income tax purposes, it shall comply with the applicable provisions of the Code relating to the exclusion of the interest on the Series TE Bonds from gross income for federal income taxation purposes. In furtherance of the foregoing covenant:

(i) The Bond Issuer shall not take or cause to be taken, or permit to be taken, any action or actions with respect to the application and investment of any proceeds of the Series TE Bonds or any other funds from whatever source derived which would cause any Series TE Bonds to be “arbitrage bonds” within the meaning of Section 148 of the Code or “private activity bonds” within the meaning of Section 141 of the Code. The Bond Issuer covenants not to consent to any amendment to, or waive performance of, any covenant of the Authority or the Servicer relating to the use, ownership or management of the projects or any portion thereof financed or refinanced by the Series TE Bonds in the tax agreements or certificates entered into by the Authority and the Servicer in connection with the Series TE Bonds unless the Bond Issuer has received an Opinion of Counsel from a nationally recognized bond counsel to the effect that such amendment or waiver would not, by itself, cause any Series TE Bonds to be “private activity bonds” within the meaning of Section 141 of the Code or otherwise cause interest on the Series TE Bonds to be included in gross income for federal income tax purposes.

(ii) The Bond Issuer shall comply with the tax agreements executed and delivered by it and the letter of instructions, if any, delivered by bond counsel, in connection with the issuance of the Series TE Bonds as to compliance with applicable provisions of the Code, as such tax covenants and agreements and letter may be amended from time to time, as a source of guidance for achieving compliance with the Code, including, without limitation, timely payments of all rebate or other amounts to the United States Department of the Treasury under Section 148 of the Code.

Notwithstanding anything else in this Bond Indenture to the contrary, including without limitation Article IV, the covenants of this Section 3.14 shall survive the payment or defeasance of the Series TE Bonds.

## ARTICLE IV
Satisfaction and Discharge; Defeasance

Section 4.01. Satisfaction and Discharge of Bond Indenture; Defeasance.

(a) This Bond Indenture shall cease to be of further effect with respect to the Bonds and the Bond Trustee, on reasonable written demand of and at the expense of the Bond Issuer, shall execute such instruments as the Bond Issuer reasonably requests acknowledging satisfaction and discharge of this Bond Indenture with respect to the Bonds, when

(i) either:

(A) all Bonds theretofore authenticated and delivered (other than (1) Bonds that have been mutilated, destroyed, lost or stolen and that have been replaced or paid as provided in Section 2.06 and (2) Bonds for whose payment money has theretofore been deposited in trust or segregated and held in trust by the Bond Issuer and thereafter repaid to the Bond Issuer or discharged from such trust, as provided in Section 3.03) have been delivered to the Bond Trustee for cancellation; or

(B) the final Payment Date has occurred with respect to all Bonds not theretofore delivered to the Bond Trustee for cancellation and the Bond Issuer has irrevocably deposited or caused to be irrevocably deposited with the Bond Trustee, in trust for such purpose, cash in an amount sufficient to pay and discharge the entire indebtedness on such Bonds not theretofore delivered to the Bond Trustee for cancellation on the final Payment Date therefor;

(ii) the Bond Issuer has paid or caused to be paid all other sums payable hereunder by the Bond Issuer; and

(iii) the Bond Issuer has delivered to the Bond Trustee an Officer's Certificate, an Opinion of Counsel and (if required by the Bond Trustee) an Independent Certificate from a firm of certified public accountants, each stating that all conditions precedent herein provided for relating to the satisfaction and discharge of this Bond Indenture with respect to the Bonds have been complied with.

(b) Notwithstanding Section 4.01(a), but subject to Sections 4.01(c) and 4.02, the Bond Issuer at any time may terminate all its obligations under this Bond Indenture with respect to the Bonds (a "Legal Defeasance"). In the event of a Legal Defeasance, the maturity of the Bonds defeased pursuant to such Legal Defeasance may not be accelerated because of an Event of Default.

Upon satisfaction of the conditions set forth herein to a Legal Defeasance, the Bond Trustee, on reasonable written demand of and at the expense of the Bond Issuer, shall execute such instruments as the Bond Issuer reasonably requests acknowledging satisfaction and discharge of the obligations that are terminated pursuant to such exercise.

(c) Notwithstanding Sections 4.01(a) and 4.01(b) above, (i) rights of registration of transfer and exchange, (ii) substitution of mutilated, destroyed, lost or stolen Bonds, (iii) rights of Bondholders to receive payments of principal and interest, (iv) Sections 4.03 and 4.04, (v) the rights, obligations and immunities of the Bond Trustee hereunder (including the rights of the Bond Trustee under Section 6.07 and the obligations of the Bond Trustee under Section 4.03) and (vi) the rights of Bondholders as beneficiaries hereof with respect to the property deposited with the Bond Trustee payable to all or any of them, shall survive until the Bonds, as to which this Bond Indenture or certain obligations hereunder have been satisfied and discharged pursuant to Section 4.01(a) or 4.01(b), have been paid in full. Thereafter, the obligations in Sections 4.04 and 6.07 shall survive.

Section 4.02. Conditions to Defeasance.

The Bond Issuer may exercise a Legal Defeasance of Bonds only if:

(a) the Bond Issuer irrevocably deposits or causes to be irrevocably deposited in trust with the Bond Trustee cash or non-callable Defeasance Securities for the payment of principal or Redemption Price of and interest on each such Serial Bond to the Scheduled Maturity Date (or, if applicable, at the election of the Bond Issuer, any earlier optional redemption date) and Term Bond to the Scheduled Sinking Fund Redemption Date (or, if applicable, any earlier optional redemption date), or with respect to the Bonds of any Tranche subject to optional redemption pursuant to Section 2.02(f), cash or non-callable Defeasance Securities for the payment of principal or Redemption Price of and interest on each such

Serial Bond to the Redemption Date set forth in the written notice provided by the Bond Issuer pursuant to Section 10.03;

(b) the Bond Issuer delivers to the Bond Trustee a certificate from a nationally recognized firm of Independent certified public accountants expressing its opinion that the payments of principal and interest when due and without reinvestment on the deposited Defeasance Securities plus any deposited cash without investment will provide cash at such times and in such amounts (but not substantially more than such amounts) as will be sufficient to pay in respect of the Bonds (i) principal on the Scheduled Maturity Date in accordance with the Expected Amortization Schedule therefor (or, if applicable, at the election of the Bond Issuer, any earlier optional redemption date) or Redemption Price on the Scheduled Sinking Fund Redemption Date in accordance with the Expected Sinking Fund Schedule therefor (or, if applicable, at the election of the Bond Issuer, any earlier optional redemption date), as applicable, and (ii) interest when due;

(c) if an election is made to redeem any such Bonds prior to maturity, the Bond Issuer irrevocably designates such Bonds for redemption on the redemption date and proper notice of redemption shall have been made or provision satisfactory to the Bond Trustee shall have been irrevocably made for the giving of such notice;

(d) no Default has occurred and is continuing on the day of such deposit and after giving effect thereto;

(e) in the case of an exercise of a Legal Defeasance with respect to the Series TE Bonds, the Bond Issuer shall have delivered to the Bond Trustee an Opinion of Counsel stating that the Holders of such Bonds will not recognize income, gain or loss for federal or New York income tax purposes as a result of such legal defeasance and will be subject to federal or New York income tax on the same amounts, in the same manner and at the same times as would have been the case if such legal defeasance had not occurred;

(f) in the case of an exercise of a Legal Defeasance with respect to the Series T Bonds, the Bond Issuer shall have delivered to the Bond Trustee an Opinion of Counsel stating that (i) the Bond Issuer has received from, or there has been published by, the Internal Revenue Service a ruling, or (ii) since the date of execution of this Bond Indenture, there has been a change in the applicable federal income tax law, in either case to the effect that, and based thereon such opinion shall confirm that, the Holders of such Bonds will not recognize income, gain or loss for federal or New York income tax purposes as a result of such legal defeasance and will be subject to federal or New York income tax on the same amounts, in the same manner and at the same times as would have been the case if such legal defeasance had not occurred

(g) the Bond Issuer delivers to the Bond Trustee an Officer’s Certificate and an Opinion of Counsel, each stating that all conditions precedent to the satisfaction and discharge of the Bonds to the extent contemplated by this Article IV have been complied with.

Section 4.03. Application of Trust Money.

All moneys or Defeasance Securities deposited with the Bond Trustee pursuant to Section 4.01 or 4.02 hereof shall be held in trust and applied by it, in accordance with the provisions of the Bonds and this Bond Indenture, to the payment, either directly or through any Paying Agent, as the Bond Trustee may determine, to the Holders of the particular Bonds for the payment of which such moneys or Defeasance Securities have been deposited with the Bond Trustee, of all sums due and to become due thereon for principal and interest, but such moneys need not be segregated from other funds except to the extent required herein or in the Servicing Agreement or required by law. Notwithstanding anything to the contrary in this Article IV, the Bond Trustee shall deliver or pay to the Bond Issuer from time to time upon Issuer Request any money or Defeasance Securities held by it pursuant to Section 4.02 which, in the opinion of a nationally recognized firm of Independent certified public accountants expressed in a written certification thereof delivered to the Bond Trustee (and not at the cost or expense of the Bond Trustee), are in excess of the amount thereof which would be required to be deposited for the purpose for which such moneys or Defeasance Securities were deposited.

Section 4.04. Repayment of Moneys Held by Paving Agent.

In connection with the satisfaction and discharge of this Bond Indenture or a Legal Defeasance with respect to the Bonds, all moneys then held by any Paying Agent other than the Bond Trustee under the provisions of this Bond Indenture with respect to such Bonds shall, upon demand of the Bond Issuer, be paid to the Bond Trustee to be held and applied according to Section 3.03 and thereupon such Paying Agent shall be released from all further liability with respect to such moneys.

## ARTICLE V
Remedies

Section 5.01. Events of Default.

"Event of Default", wherever used herein, means any one of the following events (whatever the reason for such Event of Default and whether it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body):

(a) default in the payment of any interest or redemption premium on any Bond when the same becomes due and payable, and such default shall continue for a period of five (5) Business Days; or

(b) default in the payment of the then unpaid principal of any Bond of any Tranche on the Final Maturity Date of such Tranche; or

(c) default in the observance or performance in any material respect of any covenant or agreement of the Bond Issuer made in this Bond Indenture (other than a covenant or agreement, a default in the observance or performance of which is elsewhere in this Section specifically dealt with), or any representation or warranty of the Bond Issuer made in this Bond Indenture or in any certificate or other writing delivered pursuant hereto or in connection herewith proving to have been incorrect in any material respect as of the time when the same shall have been made, and such default shall continue or not be cured, or the circumstance or condition in respect of which such misrepresentation or warranty was incorrect shall not have been eliminated or otherwise cured, for a period of thirty (30) days after the earlier of (i) the date that there shall have been given, by registered or certified mail, to the Bond Issuer by the Bond Trustee or to the Bond Issuer and the Bond Trustee by the Holders of at least twenty-five percent (25%) of the Outstanding Amount of the Bonds, a written notice specifying such default or incorrect representation or warranty and requiring it to be remedied and stating that such notice is a "Notice of Default" hereunder or (ii) the date the Bond Issuer has actual knowledge of the default; or

(d) the filing of a decree or order for relief by a court having jurisdiction in the premises in respect of the Bond Issuer or any substantial part of the Collateral in an involuntary case under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or appointing a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Bond Issuer or for any substantial part of the Collateral, or ordering the winding-up or liquidation of the Bond

Issuer's affairs, and such decree or order shall remain unstayed and in effect for a period of ninety (90) consecutive days; or

(e) the commencement by the Bond Issuer of a voluntary case or proceeding under any applicable federal or state bankruptcy, insolvency or other similar law now or hereafter in effect, or the consent by the Bond Issuer to the entry of an order for relief in an involuntary case or proceeding under any such law, or the consent by the Bond Issuer to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Bond Issuer or for any substantial part of the Collateral, or the making by the Bond Issuer of any general assignment for the benefit of creditors, or the failure by the Bond Issuer generally to pay its debts as such debts become due, or the taking of action by the Bond Issuer in furtherance of any of the foregoing; or

(f) any act or failure to act by the State of New York or any of its agencies (including the Authority), officers or employees which violates or is not in accordance with the Financing Order or the State Pledge.

The Bond Issuer shall deliver to a Responsible Officer of the Bond Trustee and the Rating Agencies, within five (5) days after an Authorized Officer has knowledge of the occurrence thereof, written notice in the form of an Officer's Certificate of any event (i) which is an Event of Default under clause (a), (b), (d), (e) or (f) or (ii) which with the giving of notice, the lapse of time, or both would become an Event of Default under clause (b) or (c), including, in each case, the status of such Default or Event of Default and what action the Bond Issuer is taking or proposes to take with respect thereto.

Section 5.02. Acceleration of Maturity; Rescission and Annulment.

If an Event of Default should occur and be continuing, then and in every such case the Bond Trustee or the Holders of Bonds representing not less than a majority of the Outstanding Amount of the Bonds may declare all the Bonds to be immediately due and payable, by a notice in writing to the Bond Issuer (and to the Bond Trustee if given by Bondholders), and upon any such declaration the unpaid principal amount of the Bonds, together with accrued and unpaid interest thereon through the date of acceleration, shall become immediately due and payable.

At any time after such declaration of acceleration of maturity has been made and before a judgment or decree for payment of the money due has been obtained by the Bond Trustee as hereinafter in this Article V provided, the Holders of Bonds representing a majority of the Outstanding Amount of the Bonds, by written notice to the Bond Issuer and the Bond Trustee, may rescind and annul such declaration and its consequences if

(a) the Bond Issuer has paid or deposited with the Bond Trustee a sum sufficient to pay:

(i) all sums paid or advanced by the Bond Trustee hereunder and the reasonable compensation, expenses, disbursements and advances of the Bond Trustee and its agents and counsel; and

(ii) all payments of principal of and interest on all Bonds and all other amounts that would then be due hereunder or upon such Bonds if the Event of Default giving rise to such acceleration had not occurred; and

(b) all Events of Default, other than the nonpayment of the principal of the Bonds that has become due solely by such acceleration, have been cured or waived as provided in Section 5.12.

No such rescission shall affect any subsequent Default or impair any right consequent thereto.

Section 5.03. Collection of Indebtedness and Suits for Enforcement by Bond Trustee.

(a) The Bond Issuer covenants that if (i) default is made in the payment of any interest on any Bond when the same becomes due and payable, and such default continues for a period of five (5) days or (ii) default is made in the payment of the then unpaid principal of any Bond on the Final Maturity Date for such Bond, the Bond Issuer will, upon demand of the Bond Trustee, pay to it, for the benefit of the Holders of the Bonds, the whole amount then due and payable on such Bonds for principal and interest, with interest upon the overdue principal and, to the extent payment at such rate of interest shall be legally enforceable, upon overdue installments of interest, at the respective rate borne by the Bonds of the applicable Tranche and in addition thereto such further amount as shall be sufficient to cover the costs and expenses of collection, including the reasonable compensation, expenses, disbursements and advances of the Bond Trustee and its agents and counsel.

(b) Subject to Sections 11.10 and 11.11, in case the Bond Issuer shall fail forthwith to pay such amounts upon such demand, the Bond Trustee, in its own name and as trustee of an express trust, may institute a Proceeding for the collection of the sums so due and unpaid, and may prosecute such Proceeding to judgment or final decree, and may enforce the same against the Bond Issuer or other obligor upon such Bonds and collect in the manner provided by law out of the property of the Bond Issuer or other obligor upon such Bonds, wherever situated, the moneys adjudged or decreed to be payable.

(c) If an Event of Default occurs and is continuing, the Bond Trustee may, as more particularly provided in Section 5.04, in its discretion, proceed to protect and enforce its rights and the rights of the Bondholders, by such appropriate Proceedings as the Bond Trustee shall deem most effective to protect and enforce any such rights, whether for the specific enforcement of any covenant or agreement in this Bond Indenture or in aid of the exercise of any power granted herein, or to enforce any other proper remedy or legal or equitable right vested in the Bond Trustee by this Bond Indenture or by law.

(d) In case there shall be pending, relative to the Bond Issuer or any other obligor upon the Bonds or any Person having or claiming an ownership interest in the Collateral, Proceedings under any applicable federal or state bankruptcy, insolvency or other similar law, or in case a receiver, assignee or trustee in bankruptcy or reorganization, liquidator, sequestrator or similar official shall have been appointed for or taken possession of the Bond Issuer or its property or such other obligor or Person, or in case of any other comparable judicial Proceedings relative to the Bond Issuer or other obligor upon the Bonds, or to the creditors or property of the Bond Issuer or such other obligor, the Bond Trustee, irrespective of whether the principal of any Bonds shall then be due and payable as therein expressed or by declaration or otherwise and irrespective of whether the Bond Trustee shall have made any demand pursuant to the provisions of this Section, shall be entitled and empowered, by intervention in such Proceedings or otherwise:

(i) to file and prove a claim or claims for the whole amount of principal and interest owing and unpaid in respect of the Bonds and to file such other papers or documents as may be necessary or advisable in order to have the claims of (A) the Bond Trustee (including any claim for reasonable compensation to the Bond Trustee and each predecessor Bond Trustee, and their respective agents, attorneys and counsel, and for reimbursement of all expenses and liabilities incurred, and all advances made, by the Bond Trustee and each predecessor Bond Trustee, except as a result of negligence or willful misconduct), (B) the Bondholders and (C) each Person for whom a claim may be made under this Bond Indenture allowed in such Proceedings;

(ii) unless prohibited by applicable law and regulations, to vote on behalf of the Bondholder in any election of a trustee, a standby trustee or Person performing similar functions in any such Proceedings;

(iii) to collect and receive any moneys or other property payable or deliverable on any such claims and to distribute all amounts received with respect to the claims of the Bondholders and of the Bond Trustee on their behalf;

(iv) to file such proofs of claim and other papers and documents as may be necessary or advisable in order to have the claims of the Bond Trustee or the Bondholders allowed in any judicial proceeding relative to the Bond Issuer, its creditors and its property; and

(v) to participate as a member, voting or otherwise, of any official committee of creditors appointed in such matter.

and any trustee, receiver, liquidator, assignee, sequestrator, custodian or other similar official in any such Proceeding is hereby authorized by each of such Bondholders to make payments to the Bond Trustee, and, in the event that the Bond Trustee shall consent to the making of payments directly to such Bondholders, to pay to the Bond Trustee (or such other beneficiary under this Bond Indenture) such amounts as shall be sufficient to cover reasonable compensation and other amounts owing hereunder to the Bond Trustee or such Person, each predecessor Bond Trustee and their respective agents, attorneys and counsel, and all other reasonable expenses and liabilities incurred, and all advances made, by the Bond Trustee and each predecessor Bond Trustee except as a result of negligence or willful misconduct.

(e) Nothing herein contained shall be deemed to authorize the Bond Trustee to authorize or consent to or vote for or accept or adopt on behalf of any Bondholder any plan of reorganization, arrangement, adjustment or composition affecting the Bonds or the rights of any Holder thereof or to authorize the Bond Trustee to vote in respect of the claim of any Bondholder in any such proceeding except, as aforesaid, to vote for the election of a trustee in bankruptcy or similar Person.

(f) All rights of action and of asserting claims under this Bond Indenture, or under any of the Bonds, may be enforced by the Bond Trustee without the possession of any of the Bonds or the production thereof in any trial or other Proceedings relative thereto, and any such action or proceedings instituted by the Bond Trustee shall be brought in its own name as trustee of an express trust, and any recovery of judgment, subject to the payment of the expenses, disbursements and compensation of the Bond Trustee, each predecessor Bond Trustee and their respective agents and attorneys, shall be for the ratable benefit of the Holders of the Bonds.

(g) In any Proceedings brought by the Bond Trustee (and also any Proceedings involving the interpretation of any provision of this Bond Indenture to which the Bond Trustee shall be a party), the Bond Trustee shall be held to represent all the Holders of the Bonds, and it shall not be necessary to make any Bondholder a party to any such Proceedings.

Section 5.04. Remedies; Priorities.

(a) If an Event of Default shall have occurred and be continuing, the Bond Trustee may do one or more of the following (subject to Section 5.05):

(i) institute Proceedings in its own name and as trustee of an express trust for the collection of all amounts then payable on the Bonds or under this Bond Indenture with respect thereto, whether by declaration or otherwise, enforce any judgment obtained, and collect from the Bond Issuer and any other obligor upon such Bonds moneys adjudged due;

(ii) institute Proceedings from time to time for the complete or partial foreclosure of this Bond Indenture with respect to the Collateral;

(iii) exercise any remedies of a secured party under the LIPA Reform Act or other applicable law and take any other appropriate action to protect and enforce the rights and remedies of the Bond Trustee and the Holders of the Bonds;

(iv) sell the Collateral or any portion thereof or rights or interest therein, at one or more public or private sales called and conducted in any manner permitted by law; and

(v) exercise all rights, remedies, powers, privileges and claims of the Bond Issuer against the Servicer under or in connection with, and pursuant to the terms of, the Servicing Agreement;

provided, however, that the Bond Trustee may not sell or otherwise liquidate any portion of the Collateral following an Event of Default, other than an Event of Default described in Section 5.01(a) or (b) unless (A) the Holders of one hundred percent (100%) of the Outstanding Amount of the Bonds consent thereto, (B) the proceeds of such sale or liquidation distributable to the Bondholders are sufficient to discharge in full all amounts then due and unpaid upon such Bonds for principal and interest after taking into account payment of all amounts due prior thereto pursuant to the priorities set forth in Section 8.02(e) or (C) the Bond Trustee determines that the Collateral will not continue to provide sufficient funds for all payments on the Bonds as they would have become due if the Bonds had not been declared immediately due and payable, and the Bond Trustee obtains the written consent of Holders of at least a majority of the Outstanding Amount of the Bonds. In determining such sufficiency or insufficiency with respect to clause (B) and (C), the Bond Trustee may, but need not, obtain and conclusively rely upon an opinion of an Independent investment banking or accounting firm of national reputation as to the feasibility of such proposed action and as to the sufficiency of the Collateral for such purpose.

(b) If the Bond Trustee collects any money pursuant to this Article V, it shall pay out such money in accordance with the priorities set forth in Section 8.02(e).

Section 5.05. Optional Possession of the Collateral.

If the Bonds have been declared to be due and payable under Section 5.02 following an Event of Default and such declaration and its consequences have not been rescinded and annulled, the Bond Trustee may, but need not, elect to maintain possession of the Collateral. It is the desire of the parties hereto and the Bondholders that there be at all times sufficient funds for the payment of principal of and interest on the Bonds, and the Bond Trustee shall take such desire into account when determining whether or not to maintain possession of the Collateral. In determining whether to maintain possession of the Collateral or sell or liquidate the same, the Bond Trustee may, but need not, obtain and conclusively rely upon an opinion of an Independent investment banking or certified public accounting firm of national reputation as to the feasibility of such proposed action and as to the sufficiency of the Collateral for such purpose.

Section 5.06. Limitation of Suits.

Each Holder agrees, by its acceptance of any Bond, to the fullest extent permitted by law, that no Holder of any Bond shall have any right to institute any Proceeding, judicial or otherwise, with respect to this Bond Indenture, or to avail itself of the right to foreclose on the Collateral or otherwise enforce the Lien and the security interest on the Collateral with respect to this Bond Indenture, or to avail itself of any remedies in the LIPA Reform Act or to utilize or enforce the Statutory Lien, or for the appointment of a receiver or trustee, or for any other remedy hereunder, unless:

(a) such Holder previously has given written notice to the Bond Trustee of a continuing Event of Default;

(b) the Holders of not less than a majority of the Outstanding Amount of the Bonds have made written request to the Bond Trustee to institute such Proceeding in respect of such Event of Default in its own name as Bond Trustee hereunder;

(c) such Holder or Holders have offered to the Bond Trustee indemnity satisfactory to it against the costs, expenses and liabilities to be incurred in complying with such request;

(d) the Bond Trustee for sixty (60) days after its receipt of such notice, request and offer of indemnity has failed to institute such Proceedings; and

(e) no direction inconsistent with such written request has been given to the Bond Trustee during such 60-day period by the Holders of at least a majority of the Outstanding Amount of the Bonds;

it being understood and intended that no one or more Holders of Bonds shall have any right in any manner whatever by virtue of, or by availing of, any provision of this Bond Indenture to affect, disturb or prejudice the rights of any other Holders of Bonds or to obtain or to seek to obtain priority or preference over any other Holders or to enforce any right under this Bond Indenture, except in the manner herein provided.

In the event the Bond Trustee shall receive conflicting or inconsistent requests and indemnity from two or more groups of Holders of Bonds, each representing less than a majority of the Outstanding Amount of the Bonds, the Bond Trustee in its sole discretion may determine what action, if any, shall be taken, notwithstanding any other provisions of this Bond Indenture.

Section 5.07. Unconditional Rights of Bondholders To Receive Principal and Interest.

Notwithstanding any other provisions in this Bond Indenture, the Holder of any Bond shall have the right, which is absolute and unconditional, (a) to receive payment of (i) the interest, if any, on such Bond on or after the due dates thereof expressed in such Bond or in this Bond Indenture or (ii) the unpaid principal, if any, of such Bonds on or after the Final Maturity Date therefor and (b) to institute suit for the enforcement of any such payment, and such right shall not be impaired without the consent of such Holder.

Section 5.08. Restoration of Rights and Remedies.

If the Bond Trustee or any Bondholder has instituted any Proceeding to enforce any right or remedy under this Bond Indenture and such Proceeding has been discontinued or abandoned for any reason or has been determined adversely to the Bond Trustee or to such Bondholder, then and in every such case the Bond Issuer, the Bond Trustee and the Bondholders shall, subject to any determination in such Proceeding, be restored severally and respectively to their former positions hereunder, and thereafter all rights and remedies of the Bond Trustee and the Bondholders shall continue as though no such Proceeding had been instituted.

Section 5.09. Rights and Remedies Cumulative.

No right or remedy herein conferred upon or reserved to the Bond Trustee or to the Bondholders is intended to be exclusive of any other right or remedy, and every right and remedy shall, to the extent permitted by law, be cumulative and in addition to every other right and remedy given hereunder or now or hereafter existing at law or in equity or otherwise. The assertion or employment of any right or remedy hereunder, or otherwise, shall not prevent the concurrent assertion or employment of any other appropriate right or remedy.

Section 5.10. Delay or Omission Not a Waiver.

No delay or omission of the Bond Trustee or any Bondholder to exercise any right or remedy accruing upon any Default or Event of Default shall impair any such right or remedy or constitute a waiver of any such Default or Event of Default or an acquiescence therein. Every right and remedy given by this Article V or by law to the Bond Trustee or to the Bondholders may be exercised from time to time, and as often as may be deemed expedient, by the Bond Trustee or by the Bondholders, as the case may be.

Section 5.11. Control by Bondholders.

The Holders of a majority of the Outstanding Amount of the Bonds (or, if less than all Tranches are affected, the affected Tranche or Tranches) shall have the right to direct the time, method and place of conducting any Proceeding for any remedy available to the Bond Trustee with respect to the Bonds of such Tranche or Tranches or exercising any trust or power conferred on the Bond Trustee with respect to such Tranche or Tranches; provided, however, that

(a) such direction shall not be in conflict with any rule of law or with this Bond Indenture;

(b) subject to the express terms of Section 5.04, any direction to the Bond Trustee to sell or liquidate the Collateral shall be by the Holders of Bonds representing not less than one hundred percent (100%) of the Outstanding Amount of the Bonds;

(c) if the conditions set forth in Section 5.05 have been satisfied and the Bond Trustee elects to retain the Collateral pursuant to such Section 5.05, then any direction to the Bond Trustee by Holders of Bonds representing less than 100 percent of the Outstanding Amount of the Bonds to sell or liquidate the Collateral shall be of no force and effect; and

(d) the Bond Trustee may take any other action deemed proper by the Bond Trustee that is not inconsistent with such direction;

provided, however, that, subject to Section 6.01, the Bond Trustee need not take any action that it determines might involve it in liability or might materially adversely affect the rights of any Bondholders not consenting to such action. Furthermore and without limiting the foregoing, the Bond Trustee shall not be required to take any action for which it reasonably believes that it will not be indemnified to its satisfaction against any cost, expense or liability.

Section 5.12. Waiver of Past Defaults.

Prior to the declaration of the acceleration of the maturity of the Bonds as provided in Section 5.02, the Holders of Bonds of a majority of the Outstanding Amount of the Bonds (or, if less than all Tranches are affected, the Holders of Bonds of a majority of the Bonds of the affected Tranche or

Tranches in the aggregate) may, by written notice to the Bond Trustee, waive any past Default or Event of Default and its consequences, except a Default (a) in payment of principal of or interest on any of the Bonds or (b) in respect of a covenant or provision hereof which cannot be modified or amended without the consent of the Holder of each Bond of all Tranches affected. In the case of any such waiver, the Bond Issuer, the Bond Trustee and the Holders of the Bonds shall be restored to their former positions and rights hereunder, respectively, but no such waiver shall extend to any subsequent or other Default or Event of Default or impair any right consequent thereto.

Upon any such waiver, such Default shall cease to exist and be deemed to have been cured and not to have occurred, and any Event of Default arising therefrom shall be deemed to have been cured and not to have occurred, for every purpose of this Bond Indenture; but no such waiver shall extend to any subsequent or other Default or Event of Default or impair any right consequent thereto.

Section 5.13. Undertaking for Costs.

All parties to this Bond Indenture agree, and each Holder of any Bond by such Holder’s acceptance thereof shall be deemed to have agreed, that any court may in its discretion require, in any suit for the enforcement of any right or remedy under this Bond Indenture, or in any suit against the Bond Trustee for any action taken, suffered or omitted by it as Bond Trustee, the filing by any party litigant in such suit of an undertaking to pay the costs of such suit, and that such court may in its discretion, subject to applicable law, assess reasonable costs, including reasonable attorneys’ fees, against any party litigant in such suit, having due regard to the merits and good faith of the claims or defenses made by such party litigant; but the provisions of this Section 5.13 shall not apply to (a) any suit instituted by the Bond Trustee, (b) any suit instituted by any Bondholder, or group of Bondholders, in each case holding in the aggregate more than ten percent (10%) of the Outstanding Amount of the Bonds or (c) any suit instituted by any Bondholder for the enforcement of the payment of (i) interest on any Bond on or after the due dates expressed in such Bond and in this Bond Indenture or (ii) the unpaid principal, if any, of any Bond on or after the Final Maturity Date therefor.

Section 5.14. Waiver of Stay or Extension Laws.

The Bond Issuer covenants (to the extent that it may lawfully do so) that it will not at any time insist upon, or plead or in any manner whatsoever, claim or take the benefit or advantage of, any stay or extension law wherever enacted, now or at any time hereafter in force, that may affect the covenants or the performance of this Bond Indenture; and the Bond Issuer (to the extent that it may lawfully do so) hereby expressly waives all benefit or advantage of any such law, and covenants that it will not hinder, delay or impede the execution of any power herein granted to the Bond Trustee, but will suffer and permit the execution of every such power as though no such law had been enacted.

Section 5.15. Action on Bonds.

The Bond Trustee’s right to seek and recover judgment on the Bonds or under this Bond Indenture shall not be affected by the seeking, obtaining or application of any other relief under or with respect to this Bond Indenture. Neither the Lien of this Bond Indenture nor any rights or remedies of the Bond Trustee or the Bondholders shall be impaired by the recovery of any judgment by the Bond Trustee against the Bond Issuer or by the levy of any execution under such judgment upon any portion of the Collateral or upon any of the assets of the Bond Issuer.

Section 5.16. Performance and Enforcement of Certain Obligations.

(a) Promptly following a request from the Bond Trustee to do so and at the Bond Issuer's expense, the Bond Issuer agrees to take all such lawful action as the Bond Trustee may reasonably request to compel or secure the performance and observance by the Seller and the Servicer, as applicable, of each of their obligations to the Bond Issuer under or in connection with the Sale Agreement and the Servicing Agreement, respectively, in accordance with the terms thereof, and to exercise any and all rights, remedies, powers and privileges lawfully available to the Bond Issuer under or in connection with the Sale Agreement and the Servicing Agreement, respectively, to the extent and in the manner directed by the Bond Trustee, including the transmission of notices of default on the part of the Seller or the Servicer thereunder and the institution of legal or administrative actions or proceedings to compel or secure performance by the Seller or the Servicer of each of their obligations under the Sale Agreement and the Servicing Agreement, respectively.

(b) If an Event of Default has occurred and shall be continuing, the Bond Trustee may, and, at the written direction of the Holders of at least a majority of the Outstanding Amount of the Bonds shall, subject to Article VI, exercise all rights, remedies, powers, privileges and claims of the Bond Issuer against the Seller or the Servicer under or in connection with the Sale Agreement and the Servicing Agreement, respectively, including the right or power to take any action to compel or secure performance or observance by the Seller or the Servicer of each of their obligations to the Bond Issuer thereunder and to give any consent, request, notice, direction, approval, extension or waiver under the Sale Agreement or the Servicing Agreement, respectively, and any right of the Bond Issuer to take such action shall be suspended.

## ARTICLE VI
The Bond Trustee and Paying Agents

Section 6.01. Duties of Bond Trustee.

(a) If an Event of Default has occurred and is continuing, the Bond Trustee shall exercise the rights and powers vested in it by this Bond Indenture and use the same degree of care and skill in their exercise as a prudent person would exercise or use under the circumstances in the conduct of such person's own affairs.

(b) Except during the continuance of an Event of Default:

(i) the Bond Trustee undertakes to perform such duties and only such duties as are specifically set forth in this Bond Indenture and no implied covenants or obligations shall be read into this Bond Indenture against the Bond Trustee; and

(ii) in the absence of bad faith on its part, the Bond Trustee may conclusively rely, as to the truth of the statements and the correctness of the opinions expressed therein, upon certificates or opinions furnished to the Bond Trustee and conforming to the requirements of this Bond Indenture; however, the Bond Trustee shall examine the certificates and opinions to determine whether or not they appear on their face to conform to the requirements of this Bond Indenture.

(c) The Bond Trustee may not be relieved from liability for its own negligence or willful misconduct, except that:

(i) this paragraph does not limit the effect of paragraph (b) of this Section;

(ii) the Bond Trustee shall not be liable for any error of judgment made in good faith by a Responsible Officer unless it is proved that the Bond Trustee was negligent in ascertaining the pertinent facts; and

(iii) the Bond Trustee shall not be liable with respect to any action it takes or omits to take in good faith in accordance with a direction received by it hereunder.

(d) Every provision of this Bond Indenture that in any way relates to the Bond Trustee is subject to paragraphs (a), (b) and (c) of this Section 6.01.

(e) The Bond Trustee shall not be liable for interest on any money received by it except as the Bond Trustee may agree in writing with the Bond Issuer.

(f) Money held in trust by the Bond Trustee need not be segregated from other funds except to the extent required by law or the terms of this Bond Indenture, the Sale Agreement or the Servicing Agreement.

(g) No provision of this Bond Indenture shall require the Bond Trustee to expend or risk its own funds or otherwise incur financial liability in the performance of any of its duties hereunder or in the exercise of any of its rights or powers, if it shall have reasonable grounds to believe that repayments of such funds or indemnity satisfactory to it against such risk or liability is not reasonably assured to it.

(h) Every provision of this Bond Indenture relating to the conduct or affecting the liability of or affording protection to the Bond Trustee shall be subject to the provisions of this Section and to the provisions of the Trust Indenture Act.

(i) In the event that the Bond Trustee is also acting as Paying Agent or Bond Registrar hereunder, this Article VI shall also be afforded to such Paying Agent or Bond Registrar.

(j) Under no circumstances shall the Bond Trustee be liable for any indebtedness of the Bond Issuer, the Servicer or the Seller evidenced by or arising under the Bonds, any Basic Document or the Bond Purchase Agreement.

Section 6.02. Rights of Bond Trustee.

(a) The Bond Trustee may conclusively rely and shall be fully protected in acting or refraining from acting in reliance upon any resolution, certificate, statement, instrument, opinion, report, notice, request, direction, consent, order, bond, debenture, paper or other document believed by it to be genuine and to have been signed or presented by the proper party or parties and the Bond Trustee need not investigate any matter or fact stated in such document;

(b) any request or direction of the Bond Issuer mentioned herein shall be sufficiently evidenced by an Issuer Request;

(c) before the Bond Trustee acts or refrains from acting, it may require and shall be entitled to receive an Officer’s Certificate or an Opinion of Counsel of external counsel of the Bond Issuer (at no cost or expense to the Bond Trustee) that such action is required or permitted hereunder. The Bond Trustee shall not be liable for any action it takes or omits to take in good faith in reliance on such Officer’s Certificate or Opinion of Counsel.

(d) the Bond Trustee may consult with counsel, and the advice or opinion of counsel with respect to legal matters relating to this Bond Indenture and the Bonds shall be full and complete authorization and protection from liability in respect of any action taken, omitted or suffered by it hereunder in good faith and in accordance with the advice or opinion of such counsel.

(e) the Bond Trustee shall be under no obligation to exercise any of the rights or powers vested in it by this Bond Indenture or to institute, conduct or defend any litigation hereunder or in relation hereto at the request or direction of any of the Bondholders pursuant to this Bond Indenture, unless such Bondholders shall have offered to the Bond Trustee security or indemnity satisfactory to it against the cost, expenses (including reasonable legal fees and expenses) and liabilities that might be incurred by it in compliance with such request or direction;

(f) the Bond Trustee shall not be bound to make any investigation into the facts or matters stated in any resolution, certificate, statement, instrument, opinion, report, notice, request, direction, consent, order, bond, debenture, paper or other document;

(g) the Bond Trustee may execute any of the trusts or powers hereunder or perform any duties hereunder either directly or by or through agents, attorneys, custodians or nominees and the Bond Trustee shall not be responsible for any misconduct or negligence on the part of, or for the supervision of, any agent, attorney, custodian or nominee appointed with due care by it hereunder; and the Bond Trustee shall give prompt written notice to the Rating Agencies of the appointment of any such agent, custodian or nominee to whom it delegates any of its express duties under this Bond Indenture; provided, that the Bond Trustee shall not be obligated to give such notice (i) if the Bond Issuer or the Holders have directed the Bond Trustee to appoint such agent, custodian or nominee (in which event the Bond Issuer shall give prompt notice to the Rating Agencies of any such direction) or (ii) of the appointment of any agents, custodians or nominees made at any time that an Event of Default on account of non-payment of principal or interest on the Bonds or insolvency of the Bond Issuer has occurred and is continuing.

(h) the Bond Trustee shall not be liable with respect to any action taken or omitted to be taken by it in good faith in accordance with the direction of the Holders of Bonds relating to the time, method and place of conducting any proceeding for any remedy available to the Bond Trustee, or exercising any trust or power conferred upon the Bond Trustee, under this Bond Indenture;

(i) the Bond Trustee shall not be required to expend or risk its own funds in the performance of any of its duties hereunder, or in the exercise of any of its rights or powers, if it shall have reasonable grounds for believing that repayment of such funds or indemnity satisfactory to it against such risk is not reasonably assured to it;

(j) the Bond Trustee shall not be personally liable for any action taken or suffered or omitted to be taken by it in good faith and reasonably believed by it to be authorized or within the discretion or rights or powers conferred upon it by this Bond Indenture; provided, however, that the Bond Trustee's conduct does not constitute willful misconduct, negligence or bad faith;

(k) in the event that the Bond Trustee is also acting as Paying Agent or Bond Registrar hereunder, the rights and protections afforded to the Bond Trustee pursuant to this Article VI shall also be afforded to such Paying Agent, authenticating agent or Bond Registrar;

(l) the Bond Trustee shall not be charged with knowledge of an Event of Default unless a Responsible Officer obtains actual knowledge of such event or the Bond Trustee receives written notice of such event from the Bond Issuer, the Servicer or a majority of the Holders of Bonds of the Tranche or Tranches so affected;

(m) without limiting its rights under bankruptcy law, when the Bond Trustee incurs expenses or renders services in connection with the insolvency or bankruptcy of any party hereto or with the Basic Documents to which it is a party such expenses (including the fees and expenses of its counsel) and the compensation for such services are intended to constitute expenses of administration under any bankruptcy or insolvency law;

(n) the Bond Trustee shall not be required to give any bond or surety in respect of the execution of the trust created herby or the power granted hereunder;

(o) in no event shall the Bond Trustee be liable for special, punitive, indirect or consequential loss or damage of any kind whatsoever (including but not limited to lost profits), even if the Bond Trustee has been advised of the likelihood of such loss or damage and regardless of the form of action;

(p) the right of the Bond Trustee to perform any discretionary act enumerated in this Bond Indenture shall not be construed as a duty, and the Bond Trustee shall not be answerable for other than its negligence or willful misconduct in the performance of any such act;

(q) the Bond Trustee shall have no duty to file any financing statement or continuation statement evidencing a security interest or to maintain any such filing, other than to file continuation statements pursuant to Section 2.14, or to maintain any insurance; and

(r) the Bond Trustee shall have no obligation to supervise the Servicer or act as successor Servicer, and shall not be liable for any default or misconduct of the Servicer.

Section 6.03. Individual Rights of Bond Trustee.

The Bond Trustee in its individual or any other capacity may become the owner or pledgee of Bonds and may otherwise deal with the Bond Issuer or its affiliates with the same rights it would have if it were not Bond Trustee. Any Paying Agent, Bond Registrar, co-registrar or co-paying agent may do the same with like rights. However, the Bond Trustee must comply with Sections 6.11 and 6.12.

Section 6.04. Bond Trustee's Disclaimer.

Except as set forth in Section 6.13, the Bond Trustee shall not be responsible for and makes no representation as to the validity or adequacy of this Bond Indenture or the Bonds, it shall not be accountable for the Bond Issuer's use of the proceeds from the Bonds, and it shall not be responsible for any statement of the Bond Issuer in the Bond Indenture or in any document issued in connection with the sale of the Bonds or in the Bonds other than the Bond Trustee's certificate of authentication. The Bond Trustee shall not be responsible for the form, character, genuineness, sufficiency, value or validity of any of the Collateral, for the validity, priority or perfection of any lien or security interest granted to it hereunder (except to the extent impaired by action or omission constituting negligence or willful misconduct on the part of the Bond Trustee, or for or in respect of the Bonds (other than the certificate of authentication for the Bonds) or the Basic Documents and the Bond Trustee shall in no event assume or incur any liability, duty or obligation to any Holder, other than as expressly provided in this Bond Indenture. The Bond Trustee shall not be liable for the default or misconduct of the Bond Issuer or the Servicer under the Basic Documents or otherwise, and the Bond Trustee shall have no obligation or liability to perform the obligations of such Persons.

Section 6.05. Notice of Defaults.

If a Default occurs and is continuing and if it is actually known to a Responsible Officer of the Bond Trustee, the Bond Trustee shall transmit to each Holder of Bonds and to the Rating Agencies notice of the Default within 30 days after actual notice of such Default was received by a Responsible Officer of the Bond Trustee (provided that the Bond Trustee shall give the Rating Agencies prompt written notice of any payment Default in respect of the Bonds). Except in the case of a Default in payment of principal of or interest on any Bond, the Bond Trustee may withhold the notice if and so long as a committee of its Responsible Officers in good faith determines that prompt notice of the Default is not likely to be material to Holders and the Default is likely to be cured and therefore that withholding the notice is in the interests of Bondholders.

Section 6.06. Reports by Bond Trustee to Holders.

(a) So long as the Bond Trustee is the Bond Registrar and Paying Agent, upon the written request of a current or former Bondholder or the Bond Issuer, the Bond Trustee shall deliver to such Bondholder, within the prescribed period of time for tax reporting purposes after the end of each calendar year, such information in its possession as may be required to enable such Holder to prepare its federal and any applicable state or local income tax returns. If the Bond Registrar and Paying Agent is other than the Bond Trustee, such Bond Registrar and Paying Agent, within the prescribed period of time for tax reporting purposes after the end of each calendar year, shall deliver to each relevant current or former Holder such information in its possession as may be required to enable such Holder to prepare its federal income and any applicable state or local tax returns.

(b) On or prior to each Payment Date therefor, the Bond Trustee will provide to each Holder of Bonds on such Payment Date a statement prepared by the Servicer and provided to the Bond Trustee which will include (to the extent applicable) the following information as to the Bonds with respect to such Payment Date or the period since the previous Payment Date, as applicable:

(i) the amount of the payment to Bondholders allocable to principal;

(ii) the amount of the payment to Bondholders allocable to interest;

(iii) the Outstanding Amount, before and after giving effect to payments allocated to principal reported under clause (i) above;

(iv) the difference, if any, between the Outstanding Amount and the Projected Principal Balance as of such Payment Date, after giving effect to payments to be made on such Payment Date;

(v) the amount on deposit in the Operating Reserve Subaccount as of the Payment Date;

(vi) the amount on deposit in the Debt Service Reserve Subaccount as of the Payment Date;

(vii) the amount, if any, on deposit in the Excess Funds Subaccount as of the Payment Date;

(viii) the amount paid to the Bond Trustee since the previous Payment Date;

(ix) the amount paid to the Servicer since the previous Payment Date;

(x) the amount paid to the Administrator since the previous Payment Date; and

(xi) any other transfers and payments to be made pursuant to the Bond Indenture since the previous Payment Date.

(c) The Bond Issuer shall send a copy of each Certificate of Compliance delivered to it pursuant to Section 3.06 of the Servicing Agreement and Annual Accountant's Report delivered to it pursuant to Section 3.07 of the Servicing Agreement to the Bond Trustee, the Bondholders and the Rating Agencies and to the Servicer for posting on the 17g-5 Website in accordance with Rule 17g-5 of the Commission.

Section 6.07. Compensation and Indemnity.

Subject to Section 8.02(e), the Bond Issuer shall pay to the Bond Trustee from time to time reasonable compensation for its services. The Bond Trustee's compensation shall not be limited by any law on compensation of a trustee of an express trust.

Subject to Section 8.02(e), the Bond Issuer shall reimburse the Bond Trustee for all reasonable out-of-pocket expenses, disbursements and advances incurred or made by it, including costs of collection, in addition to the compensation for its services. Such expenses shall include the reasonable compensation and expenses, disbursements and advances of the Bond Trustee's agents, counsel, accountants and experts. Subject to Section 8.02(e), the Bond Issuer shall indemnify, defend and hold harmless the Bond Trustee and any of its affiliates, officials, officers, directors, employees, consultants, counsel and agents (the "Indemnified Persons") from and against any and all losses, claims, actions, suits, taxes, damages, expenses (including, without limitation, reasonable legal fees and expenses) and liabilities (including liabilities under state or federal securities laws) of any kind and nature whatsoever (collectively, "Expenses"), to the extent that such Expenses arise out of or are imposed upon or asserted against such Indemnified Persons with respect to the creation, administration, operation or termination of this trust and the performance by the Bond Trustee of its duties hereunder, the failure of the Bond Issuer or any other Person (other than the Person being indemnified) to perform its obligations hereunder or under any of the Basic Documents or the Bond Purchase Agreement, or otherwise in connection with the Basic Documents, the Bond Purchase Agreement or the transactions contemplated by any of them; provided, however, that the Bond Issuer is not required to indemnify any Indemnified Person for any Expenses that result from the willful misconduct or negligence of such Indemnified Person. The willful misconduct or negligence of any Bond Trustee shall not affect the rights of any predecessor or successor Bond Trustee hereunder. The Indemnified Person shall notify the Bond Issuer as soon as is reasonably practicable of any claim for which it may seek indemnity. Failure by the Indemnified Person to so notify the Bond Issuer shall not relieve the Bond Issuer of its obligations hereunder. The Bond Issuer shall defend the claim and the Indemnified Person may have separate counsel and the Bond Issuer shall pay the fees and expenses of such counsel. The Bond Issuer will not, without the prior written consent of the Indemnified Person, settle or compromise or consent to the entry of any judgment with respect to any pending or threatened claim, action, suit or proceeding in respect of which indemnification may be sought under this Section 6.07, (whether or not the Indemnified Person is an actual or potential party to such claim or action) unless such settlement, compromise or consent includes an unconditional release of the Indemnified Person from all liability arising out of such claim, action, suit or proceeding.

The Bond Issuer's payment obligations to the Bond Trustee pursuant to this Section shall survive the discharge of this Bond Indenture or the earlier resignation or removal of the Bond Trustee. When the Bond Trustee incurs expenses after the occurrence of an Event of Default specified in Section 5.01(d) or

(e) with respect to the Bond Issuer, the expenses are intended to constitute expenses of administration under Title Il of the United States Code or any other applicable federal or state bankruptcy, insolvency or similar law.

Section 6.08. Replacement of Bond Trustee.

The Bond Trustee may resign at any time by so notifying the Bond Issuer, provided, however, that no such resignation shall be effective until either (a) the Collateral has been completely liquidated and the proceeds of the liquidation distributed to the Bondholders or (b) a successor trustee having the qualifications set forth in Section 6.11 has been designated and has accepted such trusteeship. The Holders of a majority in Outstanding Amount of the Bonds may remove the Bond Trustee by so notifying the Bond Trustee and may appoint a successor Bond Trustee. The Bond Issuer shall remove the Bond Trustee if:

(a) the Bond Trustee fails to comply with Section 6.11;

(b) the Bond Trustee is adjudged a bankrupt or insolvent;

(c) a receiver or other public officer takes charge of the Bond Trustee or its property; or

(d) the Bond Trustee otherwise becomes incapable of acting.

If the Bond Trustee resigns or is removed or if a vacancy exists in the office of Bond Trustee for any reason (the Bond Trustee in such event being referred to herein as the retiring Bond Trustee), the Bond Issuer shall promptly appoint a successor Bond Trustee.

A successor Bond Trustee shall deliver a written acceptance of its appointment to the retiring Bond Trustee and to the Bond Issuer. Thereupon the resignation or removal of the retiring Bond Trustee shall become effective, and the successor Bond Trustee shall have all the rights, powers and duties of the Bond Trustee under this Bond Indenture. The successor Bond Trustee shall mail a notice of its succession to Bondholders and to the Rating Agencies. The retiring Bond Trustee shall promptly transfer all property held by it as Bond Trustee to the successor Bond Trustee.

If a successor Bond Trustee does not take office within sixty (60) days after the retiring Bond Trustee resigns or is removed, the retiring Bond Trustee, the Bond Issuer or the Holders of a majority in Outstanding Amount of the Bonds may petition any court of competent jurisdiction for the appointment of a successor Bond Trustee.

If the Bond Trustee fails to comply with Section 6.11, any Bondholder may petition any court of competent jurisdiction for the removal of the Bond Trustee and the appointment of a successor Bond Trustee.

Notwithstanding the replacement of the Bond Trustee pursuant to this Section, the Bond Issuer’s obligations under Section 6.07 shall continue for the benefit of the retiring Bond Trustee.

Section 6.09. Successor Bond Trustee by Merger.

If the Bond Trustee consolidates with, merges or converts into, or transfers all or substantially all its corporate trust business or assets to, another corporation or banking association, the resulting, surviving or transferee corporation or banking association without any further act shall be the successor

Bond Trustee. The successor Bond Trustee shall mail a notice of its merger, conversion, consolidation or transfer to the Rating Agencies.

In case at the time such successor or successors by merger, conversion, consolidation or transfer to the Bond Trustee shall succeed to the trusts created by this Bond Indenture any of the Bonds shall have been authenticated but not delivered, any such successor to the Bond Trustee may adopt the certificate of authentication of any predecessor trustee, and deliver such Bonds so authenticated; and in case at that time any of the Bonds shall not have been authenticated, any successor to the Bond Trustee may authenticate such Bonds either in the name of any predecessor hereunder or in the name of the successor to the Bond Trustee; and in all such cases such certificates shall be valid for all purposes hereunder and under the Bonds.

Section 6.10. Appointment of Co-Trustee or Separate Trustee.

(a) Notwithstanding any other provisions of this Bond Indenture, at any time, for the purpose of meeting any legal requirement of any jurisdiction in which any part of the Collateral may at the time be located or to address divergent or conflicting interests among Holders of Bonds of separate Tranches of Bonds as a result of variations in terms of the respective underlying Bonds of corresponding Tranches, the Bond Trustee shall have the power and may execute and deliver all instruments to appoint one or more Persons to act as a co-trustee or co-trustees, or separate trustee or separate trustees, of all or any part of the Collateral, and to vest in such Person or Persons, in such capacity and for the benefit of the Bondholders, such title to the Collateral, or any part hereof, and, subject to the other provisions of this Section 6.10, such powers, duties, obligations, rights and trusts as the Bond Trustee may consider necessary or desirable. No co-trustee or separate trustee hereunder shall be required to meet the terms of eligibility as a successor trustee under Section 6.11 and no notice to Bondholders of the appointment of any co-trustee or separate trustee shall be required under Section 6.08 hereof. Notice of any such appointment shall be promptly given to each Rating Agency by the Bond Trustee.

(b) Every separate trustee and co-trustee shall, to the extent permitted by law, be appointed and act subject to the following provisions and conditions:

(i) all rights, powers, duties and obligations conferred or imposed upon the Bond Trustee shall be conferred or imposed upon and exercised or performed by the Bond Trustee and such separate trustee or co-trustee jointly (it being understood that such separate trustee or co-trustee is not authorized to act separately without the Bond Trustee joining in such act), except to the extent that under any law of any jurisdiction in which any particular act or acts are to be performed the Bond Trustee shall be incompetent or unqualified to perform such act or acts, in which event such rights, powers, duties and obligations (including the holding of title to the Collateral or any portion thereof in any such jurisdiction) shall be exercised and performed singly by such separate trustee or co-trustee, but solely at the direction of the Bond Trustee;

(ii) no trustee hereunder shall be personally liable by reason of any act or omission of any other trustee hereunder; and

(iii) the Bond Trustee may at any time accept the resignation of or remove any separate trustee or co-trustee.

(c) Any notice, request or other writing given to the Bond Trustee shall be deemed to have been given to each of the then separate trustees and co-trustees, as effectively as if given to each of them. Every instrument appointing any separate trustee or co-trustee shall refer to this Bond Indenture and the conditions of this Article VI. Each separate trustee and co-trustee, upon its acceptance of the trusts conferred, shall be vested with the estates or property specified in its instrument of appointment, either jointly with the Bond Trustee or separately, as may be provided therein, subject to all the provisions of this Bond Indenture, specifically including every provision of this Bond Indenture relating to the conduct of, affecting the liability of, or affording protection to, the Bond Trustee. Every such instrument shall be filed with the Bond Trustee.

(d) Any separate trustee or co-trustee may at any time constitute the Bond Trustee, its agent or attorney-in-fact with full power and authority, to the extent not prohibited by law, to do any lawful act under or in respect of this Bond Indenture on its behalf and in its name. If any separate trustee or co-trustee shall die, become incapable of acting, resign or be removed, all of its estates, properties, rights, remedies and trusts shall vest in and be exercised by the Bond Trustee, to the extent permitted by law, without the appointment of a new or successor trustee.

Section 6.11. Eligibility; Disqualification.

The Bond Trustee shall at all times be a corporation organized and doing business under the laws of the United States or of any State or of the District of Columbia which (i) is authorized under such laws to exercise corporate trust powers, and (ii) is subject to supervision or examination by federal, State or District of Columbia authority. The Bond Trustee shall have a combined capital and surplus of at least $100,000,000 as set forth in its most recent published annual report of condition and it shall have a long term debt rating of at least “A” (or the equivalent thereof) or better by the Rating Agencies.

Section 6.12. Representations and Warranties of Bond Trustee.

The Bond Trustee hereby represents and warrants that:

(a) the Bond Trustee is a New York banking corporation validly existing in good standing under the laws of the State of New York; and

(b) the Bond Trustee has full power, authority and legal right to execute, deliver and perform this Bond Indenture and the Basic Documents to which the Bond Trustee is a party and has taken all necessary action to authorize the execution, delivery, and performance by it of this Bond Indenture and such Basic Documents.

Section 6.13. The Paying Agents.

(a) Each Paying Agent other than the Bond Trustee shall execute and deliver to the Bond Trustee an instrument in which such Paying Agent shall agree with the Bond Trustee (and if the Bond Trustee acts as Paying Agent, it hereby so agrees), subject to the provisions of this Section 6.13, that such Paying Agent will:

(i) hold all sums held by it for the payment of amounts due with respect to the Bonds in trust for the benefit of the Persons entitled thereto until such sums shall be paid to such Persons or otherwise disposed of as herein provided and pay such sums to such Persons as herein provided;

(ii) give the Bond Trustee written notice of any Default by the Bond Issuer of which it has actual knowledge in the making of any payment required to be made with respect to the Bonds;

(iii) at any time during the continuance of any such Default, upon the written request of the Bond Trustee, forthwith pay to the Bond Trustee all sums so held in trust by such Paying Agent;

(iv) immediately resign as a Paying Agent and forthwith pay to the Bond Trustee all sums held by it in trust for the payment of Bonds if at any time the Paying Agent determines that it has ceased to meet the standards required to be met by a Paying Agent at the time of such determination;

(v) comply with all requirements of the Code and other tax laws with respect to the withholding from any payments made by it on any Bonds of any applicable withholding taxes imposed thereon and with respect to any applicable reporting requirements in connection therewith; and

(vi) keep such books and records as shall be consistent with prudent corporate trust industry practice and to make such books and records available for inspection by the Bond Issuer and the Bond Trustee at all reasonable times.

(b) The Paying Agent shall be a corporation or association duly organized under the laws of the United States of America or any state or territory thereof, or a bank or trust company having a combined capital stock, surplus and undivided profits of at least $50,000,000 and authorized by law to perform all the duties imposed upon it by this Bond Indenture. The Paying Agent may at any time resign and be discharged of the duties and obligations created by this Bond Indenture by giving at least 60 days' notice to the Bond Issuer and the Bond Trustee. In the event that the Bond Issuer shall fail to appoint a successor Paying Agent, upon the resignation or removal of the Paying Agent, the Bond Trustee shall either appoint a Paying Agent or itself act as Paying Agent until the appointment of a successor Paying Agent. Any successor Paying Agent shall have a long term debt rating of at least "A" by the Rating Agencies. The Paying Agent may be removed at any time by an instrument signed by the Bond Issuer filed with the Bond Trustee.

(c) In the event of the resignation or removal of the Paying Agent, the Paying Agent shall deliver any Bonds and money held by it in such capacity to its successor or, if there is no successor, to the Bond Trustee.

Section 6.14. Custody of Collateral.

The Bond Trustee shall hold such of the Collateral (and any other collateral that may be granted to the Bond Trustee) as consists of instruments, deposit accounts, securities accounts, negotiable documents, money, goods, letters of credit, and advices of credit in the State of New York. The Bond Trustee shall hold such of the Collateral as constitutes investment property through the Securities Intermediary (which, as of the date hereof, is The Bank of New York Mellon). The initial Securities Intermediary hereby agrees (and each future Securities Intermediary shall agree) with the Bond Trustee that (a) such investment property shall at all times be credited to a securities account of the Bond Trustee, (b) the Securities Intermediary shall treat the Bond Trustee as entitled to exercise the rights that comprise each financial asset credited to such securities account, (c) all property credited to such securities account shall be treated as a financial asset, (d) the Securities Intermediary shall comply with entitlement orders originated by the Bond Trustee without the further consent of any other Person, (e) the Securities Intermediary will not agree with any Person other than the Bond Trustee to comply with entitlement orders originated by such other Person, (f) such securities accounts and the property credited thereto shall not be subject to any Lien or right of set-off in favor of the Securities Intermediary or anyone claiming through it (other than the Bond Trustee), and (g) such securities accounts shall be governed by the internal laws of the State of New York. Terms used in the preceding sentence that are defined in the UCC and not otherwise defined herein shall have the meaning set forth in the UCC. Except as permitted by this Section 6.14, or elsewhere in this Bond Indenture, the Bond Trustee shall not hold Collateral through an agent or a nominee.

## ARTICLE VII
The Bondholders

Section 7.01. Acts of Bondholders; Evidence of Ownership.

(a) Any request, demand, authorization, direction, notice, consent, waiver or other action provided by this Bond Indenture to be given or taken by Bondholders may be embodied in and evidenced by one or more instruments of substantially similar tenor signed by such Bondholders in person or by agents duly appointed in writing; and except as herein otherwise expressly provided such action shall become effective when such instrument or instruments are delivered to the Bond Trustee, and, where it is hereby expressly required, to the Bond Issuer. Such instrument or instruments (and the action embodied therein and evidenced thereby) are herein sometimes referred to as the "Act" of the Bondholders signing such instrument or instruments. Proof of execution of any such instrument or of a writing appointing any such agent shall be sufficient for any purpose of this Bond Indenture and (subject to Section 6.01) conclusive in favor of the Bond Trustee and the Bond Issuer, if made in the manner provided in this Section 7.01.

(b) The fact and date of the execution by any person of any such instrument or writing may be proved in any manner that the Bond Trustee deems sufficient.

(c) The ownership of Bonds shall be proved by the Bond Register.

(d) Any request, demand, authorization, direction, notice, consent, waiver or other action by the Holder of any Bonds shall bind the Holder of every Bond issued upon the registration thereof or in exchange therefor or in lieu thereof, in respect of anything done, omitted or suffered to be done by the Bond Trustee or the Bond Issuer in reliance thereon, whether or not notation of such action is made upon such Bond.

Section 7.02. Notice to Bondholders.

Where this Bond Indenture provides for notice to Bondholders of any event, such notice shall be sufficiently given (unless otherwise herein expressly provided) if in writing and mailed, first-class, postage prepaid to each Bondholder affected by such event, at such Bondholder's address as it appears on the Bond Register, not later than the latest date, and not earlier than the earliest date, prescribed for the giving of such notice. In any case where notice to Bondholders is given by mail, neither the failure to mail such notice nor any defect in any notice so mailed to any particular Bondholder shall affect the sufficiency of such notice with respect to other Bondholders, and any notice that is mailed in the manner herein provided shall conclusively be presumed to have been duly given.

Where this Bond Indenture provides for notice in any manner, such notice may be waived in writing by any Person entitled to receive such notice, either before or after the event, and such waiver shall be the equivalent of such notice. Waivers of notice by Bondholders shall be filed with the Bond Trustee but such filing shall not be a condition precedent to the validity of any action taken in reliance upon such a waiver.

In case, by reason of the suspension of regular mail service as a result of a strike, work stoppage or similar activity, it shall be impractical to mail notice of any event of Bondholders when such notice is required to be given pursuant to any provision of this Bond Indenture, then any manner of giving such notice as shall be satisfactory to the Bond Trustee shall be deemed to be a sufficient giving of such notice.

Where this Bond Indenture provides for notice to the Rating Agencies, failure to give such notice shall not affect any other rights or obligations created hereunder, and shall not under any circumstance constitute a Default or Event of Default.

Section 7.03. Bond Issuer to Furnish Bond Trustee Names and Addresses of Bondholders.

Unless the Bond Trustee is the Bond Registrar, the Bond Issuer shall furnish or cause to be furnished to the Bond Trustee (a) not more than five (5) days after the earlier of (i) each Record Date and (ii) six (6) months after the last Record Date, a list, in such form as the Bond Trustee may reasonably require, of the names and addresses of the Holders as of such Record Date, and (b) at such other times as the Bond Trustee may request in writing, within 30 days after receipt by the Bond Issuer of any such request, a list of similar form and content as of a date not more than 10 days prior to the time such list is furnished. The Bond Trustee shall be the initial Bond Registrar hereunder.

Section 7.04. Preservation of Information; Communications to Bondholders.

(a) The Bond Trustee shall preserve, in as current a form as is reasonably practicable, the names and addresses of the Holders contained in the most recent list furnished to the Bond Trustee as provided in Section 7.03 and the names and addresses of Holders received by the Bond Trustee in its capacity as Bond Registrar. The Bond Trustee may destroy any list furnished to it as provided in such Section 7.03 upon receipt of a new list so furnished.

(b) Upon the written request of any Holder or group of Holders, each of whom has held its Bond for at least six (6) months, the Bond Trustee shall afford the Holder or Holders making such request a copy of a current list of Holders of the Bonds, for purposes of communicating with other Holders with respect to their rights hereunder. The Bond Trustee may elect not to afford the requesting Holders access to the list of Holders of the Bonds if it agrees to mail the desired communication or proxy, on behalf and at the expense of the requesting Holders, to all Holders of the Bonds.

Section 7.05. Provisions of Servicer Reports.

Upon the written request of any Bondholder or any Rating Agency to the Bond Trustee addressed to the Corporate Trust Office, the Bond Registrar, or in its absence or failure the Paying Agent, shall provide such requesting party, the Bond Trustee and the Paying Agent or Bond Registrar, as applicable, with a copy of any Semiannual Servicer Certificate, Annual Accountant's Report and any other report of the Servicer referred to in the Servicing Agreement.

## ARTICLE VIII
Accounts, Disbursements and Releases

Section 8.01. Collection of Money.

Except as otherwise expressly provided herein, the Bond Trustee may demand payment or delivery of, and shall receive and collect, directly and without intervention or assistance of any fiscal agent or other intermediary, all money and other property payable to or receivable by the Bond Trustee pursuant to this Bond Indenture and the other Basic Documents. The Bond Trustee shall apply all such money received by it as provided in this Bond Indenture. Except as otherwise expressly provided in this Bond Indenture, if any default occurs in the making of any payment or performance under any agreement or instrument that is part of the Collateral, the Bond Trustee may take such action as may be appropriate to enforce such payment or performance, subject to Article VI, including the institution and prosecution of appropriate Proceedings. Any such action shall be without prejudice to any right to assert a Default or Event of Default under this Bond Indenture and any right to proceed thereafter as provided in Article V.

Section 8.02. Collection Account.

(a) (i) Prior to the Issuance Date, the Bond Trustee shall establish or cause to be established at the Bond Trustee's Corporate Trust Office, or at another Eligible Institution, one or more segregated trust accounts in the Bond Trustee's name for the deposit of Restructuring Property and other amounts remitted under the Servicing Agreement or otherwise received with respect to the Collateral (collectively, the "Collection Account"). The Bond Trustee shall hold the Collection Account for the benefit of Bondholders, the Bond Trustee and the other Persons indemnified hereunder. The Collection Account will consist of four Subaccounts: a general subaccount (the "General Subaccount"), an excess funds subaccount (the "Excess Funds Subaccount"), a reserve subaccount (the "Reserve Subaccount"), a Financing Costs subaccount (the "Upfront Financing Costs Subaccount"). The Reserve Subaccount shall consist of two subaccounts, an operating reserve subaccount (the "Operating Reserve Subaccount") and a debt service reserve subaccount (the "Debt Service Reserve Subaccount"). For administrative purposes, the Subaccounts, including, without limitation, the Subaccounts within the Reserve Subaccount, may be established by the Bond Trustee as separate accounts. All references to the Collection Account shall be deemed to include reference to all Subaccounts.

(ii) Concurrently with the issuance of the Bonds, there shall be deposited into the Operating Reserve Subaccount moneys provided by the Authority in an amount equal to the Required Operating Reserve Level and into the Upfront Financing Costs Subaccount proceeds of the Bonds expected to be used for Upfront Financing Costs as provided in the Issuance Advice Letter. Concurrently with the issuance of the Bonds, there shall also be deposited into the Debt Service Reserve Subaccount proceeds of the Bonds in an amount equal to the Required Debt Service Reserve Level. All amounts in the Collection Account not allocated to any other Subaccount shall be allocated to the General Subaccount. Prior to the initial Payment Date, all amounts in the Collection Account (other than funds deposited into the Operating Reserve Subaccount, up to the Required Operating Reserve Level, in the Debt Service Reserve Subaccount, up to the Required Debt Service Reserve Level, and in the Upfront Financing Costs Subaccount, up to the amount initially deposited therein) shall be allocated to the General Subaccount. Withdrawals from and deposits to each of the Subaccounts shall be made as set forth in this Section 8.02.

(iii) The Collection Account shall at all times be maintained in an Eligible Account and only the Bond Trustee shall have access to the Collection Account for the purpose of making deposits in and withdrawals from the Collection Account in accordance with this Bond Indenture. Funds in the Collection Account shall not be commingled with any other moneys. Except as provided in Section 8.03, all moneys deposited from time to time in the Collection Account, all deposits therein pursuant to this Bond Indenture, and all investments made in Eligible Investments with such moneys, including all income or other gain from such investments, shall be held by the Bond Trustee in the Collection Account as part of the Collateral as herein provided.

(iv) The Lien of this Bond Indenture is pursuant to, in accordance with and governed by subdivision 2 of Section 7 of the LIPA Reform Act. The following provisions of this paragraph are included only to the extent Article 8 of the UCC is deemed to apply to any part of the Trust Estate, in addition to, and not as a qualification or limitation of, the preceding sentence. The Securities Intermediary hereby confirms that (A) the Collection Account is, or at inception will be established as, a "securities account" as such term is defined in Section 8-501(a) of the UCC, (B) it is a "securities intermediary" (as such term is defined in Section 8-102(a) (14) of the UCC) and is acting in such capacity with respect to such accounts, and (C) the Bond Trustee for the benefit of the Bondholders is the sole "entitlement holder" (as such term is defined in Section 8-102(a)(7) of the UCC) with respect to such accounts and no other Person shall have the right to give "entitlement orders" (as such term is defined in Section 8-102(a)(8)) with respect to such accounts, and agrees that each item of property (whether investment property, financial asset, security, instrument or cash) received by it will be credited to the Collection Account and shall be treated by it as a "financial asset" within the meaning of Section 8-102(a)(9) of the UCC. Notwithstanding anything to the contrary, New York State shall be deemed to be the jurisdiction of the Securities Intermediary for purposes of Section 8-110 of the UCC, and the Collection Account (as well as the securities entitlements related thereto) shall be governed by the laws of the State of New York.

(b) The Bond Trustee shall have sole dominion and exclusive control over all moneys in the Collection Account and shall apply such amounts therein as provided in this Section 8.02.

(c) All remittances to the Bond Trustee as provided in Sections 3.03 and 5.11 and Annex 2 of the Servicing Agreement shall be deposited in the General Subaccount. All deposits to and withdrawals from the Collection Account and all allocations to the Subaccounts of the Collection Account shall be made by the Bond Trustee in accordance with the written instructions provided by the Servicer in the Semiannual Servicer Certificate or as otherwise provided herein. To the extent that the Bond Trustee shall receive from the Servicer or the Allocation Agent an amount not constituting Collateral, other than as Excess Remittances to be repaid as contemplated by the last paragraph of Section 8.02(e) below, the Bond Trustee shall promptly notify the Bond Issuer, the Authority, the Allocation Agent and the Servicer and remit such amount to or upon the order of the Authority and thereupon notify the Authority of such remittance.

(d) On any Business Day upon which the Bond Trustee receives a written request from the Administrator stating that any Operating Expense payable by the Bond Issuer (but only as described in clauses (i) through (iv) of Section 8.02(e) below) will become due and payable prior to the next succeeding Payment Date, and setting forth the amount and nature of such Operating Expenses, as well as any supporting documentation that the Bond Trustee may reasonably request, the Bond Trustee, upon receipt of such information, will make payment of such Operating Expenses on or before the date such payment is due from amounts on deposit in the General Subaccount, the Excess Funds Subaccount and the Operating Reserve Subaccount, in that order and only to the extent required to make such payment. In no event shall amounts on deposit in the Debt Service Reserve Subaccount be applied to pay Operating Expenses or to any purpose other than the payment of amounts payable under clauses (v) through (vii) of Section 8.02(e) below.

(e) On each Payment Date, or for any amount payable under clauses (i) through (iv) below on any Business Day pursuant to Section 8.02(d), the Bond Trustee shall apply, at the direction of the Servicer, all amounts on deposit in the Collection Account (other than amounts on deposit in the Debt Service Reserve Subaccount which shall be applied solely to amounts payable under clauses (v) through (vii) below), including all earnings thereon, to allocate or pay the following amounts, in accordance with the Semiannual Servicer Certificate, in the following priority:

(i) all fees, costs, expenses (including legal fees and expenses) and, to the extent not in excess of $800,000 in each calendar year, indemnity amounts owed by the Bond Issuer to the

Bond Trustee under the applicable Basic Documents shall be paid to the Bond Trustee; provided, however, that in the event of an Event of Default the provisions of Sections 5.02(a)(ii), 5.13 and 6.01(g) shall apply;

(ii) the Servicing Fee for such Payment Date, and all unpaid Servicing Fees from prior Payment Dates, to the extent of Servicing Fees not in excess of 0.60% of the aggregate initial principal amount of the Bonds in each calendar year shall be paid to the Servicer;

(iii) the Administration Fee and all unpaid Administration Fees from prior Payment Dates shall be paid to the Administrator;

(iv) the payment of all other Operating Expenses (other than as provided by clauses (viii) and (ix) below) for such Payment Date shall be paid to the Persons entitled thereto;

(v) (A) first, any overdue interest (together with, to the extent lawful, interest on such overdue interest at the applicable Bond Interest Rate) and (B) second, interest for such Payment Date shall be paid to the Bondholders;

(vi) principal due and payable on the Bonds as a result of an Event of Default (assuming the Bonds have been declared immediately due and payable) or on the Final Maturity Date of a Tranche of the Bonds shall be paid to the Bondholders;

(vii) principal for such Payment Date shall be paid to the Bondholders in accordance with the priorities of Section 2.02(c);

(viii) indemnity amounts owed by the Bond Issuer to the Bond Trustee under the applicable Basic Documents, to the extent in excess of $800,000 in each calendar year, shall be paid to the Bond Trustee and premiums for directors' and officers' liability insurance for trustees and officers of the Bond Issuer shall be paid to the provider of such insurance or, if such premium is paid by the Administrator pursuant to Section 1.03(a) of the Administration Agreement, the amount of such premium shall be paid to the Administrator in reimbursement thereof;

(ix) the Servicing Fee for such Payment Date, and all unpaid Servicing Fees from prior Payment Dates, to the extent of Servicing Fees in excess of 0.60% of the aggregate initial principal amount of the Bonds in each calendar year shall be paid to the Servicer;

(x) the amount, if any, by which the Required Debt Service Reserve Level exceeds the amount in the Debt Service Reserve Subaccount as of such Payment Date shall be paid or allocated to the Debt Service Reserve Subaccount;

(xi) the amount, if any, by which the Required Operating Reserve Level exceeds the amount in the Operating Reserve Subaccount as of such Payment Date shall be paid or allocated to the Operating Reserve Subaccount;

(xii) the amount, if any, by which the amount in the Debt Service Reserve Subaccount exceeds the Required Debt Service Reserve Level on any Payment Date shall be retained in the Debt Service Reserve Subaccount until the next Payment Date, at which time such excess amount in the Debt Service Reserve Subaccount shall be applied to the payment of amounts then due under clauses (v) through (vii) above prior to any other moneys available for such purpose and, to the extent that such excess amount exceeds amounts then due under such clause on such next Payment Date, such excess amount shall continue to be held in the Debt Service Reserve

Subaccount and shall be applied under such clauses (v) through (vii) prior to any other moneys available for such purpose on succeeding Payment Dates until fully applied; and

(xiii) the balance, if any, shall be paid or allocated to the Excess Funds Subaccount for distribution on subsequent Payment Dates.

The entire amount on deposit in the Debt Service Reserve Subaccount shall be used to the extent practicable to make all or a portion of the last remaining payments contemplated by clauses (v), (vi) and (vii) above and the entire amount on deposit in the Excess Funds Subaccount shall be used to the extent practical to make all or a portion of the last remaining payments contemplated by clause (v), (vi) and (vii) above and any unpaid Operating Expenses, then the balance, if any, in the Excess Funds Subaccount shall be paid to the Bond Issuer, free from the Lien of this Bond Indenture and shall be applied by the Bond Issuer to customer refunds in accordance with the Financing Order. When no Bonds remain Outstanding and all Ongoing Financing Costs (including any rebate or other amounts payable to the United States of America under Section 148 of the Code) have been paid, or their payment provided for, in full, then the balance, if any, in the Collection Account (including all Subaccounts therein) shall be deposited in the Operating Reserve Subaccount and paid to or at the direction of the Bond Issuer and applied to customer refunds in accordance with the Financing Order.

All partial payments of interest pursuant to clause (v) shall be allocated among each Tranche of Bonds *pro rata* based upon the respective amounts of interest owed on the Bonds of each Tranche, and allocated and paid to Holders within each Tranche *pro rata* based upon the respective principal amount of Bonds held. All partial payments of principal pursuant to clause (vi) shall be made to such Holders *pro rata* based on the respective principal amounts of Bonds held by such Holders. All payments of principal or Redemption Price pursuant to clause (vii) above with respect to each Tranche shall be made to the Holders of the Tranche then entitled to payment, based upon, in the case of Serial Bonds, the Outstanding Amount of such Bonds and, in the case of Term Bonds, the Scheduled Sinking Fund Payment of such Bonds, all in accordance with the priorities of Section 2.02(c).

Amounts on deposit in the General Subaccount or the Excess Funds Subaccount if necessary shall be applied, at the direction of the Authority, to pay Excess Remittances to the Servicer pursuant to Section 3.03(c) of the Servicing Agreement.

(f) If on any Payment Date, or for any amounts payable under clauses (i) through (iv) above, on any Business Day, funds on deposit in the General Subaccount are insufficient to make the payments contemplated by clauses (i) through (ix) of Section 8.02(e), the Bond Trustee shall (i) first, draw from amounts on deposit in the Excess Funds Subaccount and (ii) second, draw from amounts on deposit in the Operating Reserve Subaccount, in each case, up to the amount of such shortfall in order to make the payments contemplated by clauses (i) through (ix) of Section 8.02(e); provided, however, that if on the December 15, 2022, Payment Date, funds on deposit in the General Subaccount are insufficient to make the payments contemplated by clause (v) of Section 8.02(e), then the Bond Trustee shall (i) first draw from amounts on deposit in the Excess Funds Subaccount and (ii) second, draw from amounts on deposit in the Debt Service Reserve Account, up to the amount of such shortfall in order to make the payments contemplated by clause (v) of Section 8.02(e). In addition, except as described in the preceding sentence, if on any Payment Date, funds on deposit in the General Subaccount, together with moneys available in the Excess Funds Subaccount and the Operating Reserve Subaccount, are insufficient to make the payments contemplated by clauses (v) through (vii) of Section 8.02(e), the Bond Trustee shall then draw from amounts on deposit in the Debt Service Reserve Subaccount, up to the amount of such shortfall in order to make the payments contemplated by such clauses (v) through (vii) of Section 8.02(e). In addition, if on any Payment Date funds on deposit in the General Subaccount are insufficient to make the allocation contemplated by clause (x) of Section 8.02(e), the Bond Trustee shall draw from amounts on deposit in the Excess Funds Subaccount to make such allocation. If on any Payment Date funds on deposit in the Collection Account are insufficient to make the transfers contemplated by clause (v), (vi) or (vii) of Section 8.02(e), the Bond Trustee will allocate the funds drawn pursuant to the first and second sentences of this paragraph among the Tranches pro rata as provided in Section 8.02(e).

(g) In the event bonds, notes or other obligations authorized by Section 2.17 are issued to refund in advance of maturity any Bonds, amounts may be withdrawn from the Operating Reserve Subaccount to pay or provide for the payment of such Bonds; provided, however, that immediately after such withdrawal, there shall remain on deposit in the Operating Reserve Subaccount an amount of moneys and Eligible Investments at least equal in the aggregate to the Required Operating Reserve Level then applicable to the Bonds.

(h) Eligible Investments shall, for purposes of determining the amount on deposit in any Subaccount, be valued at par or maturity value.

Section 8.03. General Provisions Regarding the Collection Account.

(a) So long as no Default or Event of Default shall have occurred and be continuing, all or a portion of the funds in the Collection Account shall be invested in Eligible Investments and reinvested by the Bond Trustee at the written direction provided by or on behalf of the Bond Issuer, upon Issuer Order; provided, however, that (i) such Eligible Investments shall mature or be redeemable at the option of the holder on or prior to the Business Day next preceding the next Payment Date or, if applicable, special payment date pursuant to Section 2.08(c), and (ii) such Eligible Investment shall not be sold, liquidated or otherwise disposed of at a loss prior to the maturity or redemption date thereof. All income or other gain from investments of moneys deposited in the Collection Account shall be deposited by the Bond Trustee in the Collection Account, and any loss resulting from such investments shall be charged to the Collection Account. The Bond Issuer will not direct the Bond Trustee to make any investment of any funds or to sell any investment held in the Collection Account unless the security interest Granted and perfected in such Collection Account will continue to be perfected in such investment or the proceeds of such sale, in either case without any further action by any Person, and, in connection with any direction to the Bond Trustee to make any such investment or sale, if requested by the Bond Trustee, the Bond Issuer shall deliver to the Bond Trustee an Opinion of Counsel, reasonably acceptable to the Bond Trustee, to such effect. The Bond Trustee shall have no liability in respect of losses incurred as a result of the liquidation of any Eligible Investment prior to its stated maturity or date of redemption the failure of the Bond Issuer to provide timely written investment direction. The Bond Trustee shall have no obligation to invest or reinvest any amounts held hereunder in the absence of written investment direction pursuant to an Issuer Order. If the rating of the Eligible Institution, which may be the Bond Trustee's Corporate Trust Office, falls below the rating requirements set forth in clause (b) of the definition of Eligible Institution, the Bond Issuer shall, within one (1) month after notice of such rating change, cause the Collection Account to be transferred to an institution meeting the requirements set forth in clause (b) of the definition of "Eligible Institution."

(b) Subject to Section 6.01(c), the Bond Trustee shall not in any way be held liable by reason of any insufficiency in the Collection Account resulting from any loss on any Eligible Investment included therein except for losses attributable to the Bond Trustee's failure to make payments on such Eligible Investments issued by the Bond Trustee, in its commercial capacity as principal obligor and not as trustee, in accordance with their terms.

(c) If (i) the Bond Issuer shall have failed to give written investment directions for any funds on deposit in the Collection Account to the Bond Trustee by 11:00 am. Eastern Time (or such other time as may be agreed by the Bond Issuer and Bond Trustee) on any Business Day or (ii) a Default or Event of

Default shall have occurred and be continuing with respect to the Bonds but the Bonds shall not have been declared immediately due and payable pursuant to Section 5.02, then the Bond Trustee shall, to the fullest extent practicable, invest and reinvest funds in the Collection Account in one or more money market funds (described in clause (d) of the definition of "Eligible Investments") specified in the most recent investment directions delivered by the Bond Issuer to the Bond Trustee with respect to such type of Eligible Investments; provided, however, that such investments shall mature (i) on or before the Business Day preceding the next Payment Date or, if and when established, any special payment date pursuant to Section 2.08(c), and (ii) in the case of investments in the Excess Funds Subaccount after June 15, which mature on or before the Business Day preceding the next June 30 (or such earlier date(s) as the Servicer shall specify to the Bond Trustee in writing) to permit Excess Remittances to be paid pursuant to Section 3.03(c) of the Servicing Agreement; and provided further, however, that if the Bond Issuer has never delivered written investment directions to the Bond Trustee, the Bond Trustee shall not invest or reinvest such funds in any investments.

Section 8.04. Release of Collateral.

(a) So long as the Bond Issuer is not in default hereunder and no Default hereunder would occur as a result of such action, the Bond Issuer, through the Servicer, may collect, sell or otherwise dispose of written-off receivables, at any time and from time to time in the ordinary course of business, without any notice to, or release or consent by, the Bond Trustee or the Holders, but only as and to the extent permitted by the Basic Documents. All proceeds of such dispositions that are allocable to Charges shall become Collateral and be deposited to the General Subaccount pursuant to the Servicing Agreement. Without limiting the foregoing, the Bond Issuer, through the Servicer, may at any time and from time to time without any notice to, or release or consent by, the Bond Trustee or the Holders, sell or otherwise dispose of any Collateral which is part of a utility bill previously written-off as a defaulted or uncollectible account in accordance with the Servicing Agreement and the requirements of the immediately preceding sentence.

(b) The Bond Trustee may, and when required by the provisions of this Bond Indenture shall, execute instruments to release property from the Lien of this Bond Indenture, or convey the Bond Trustee's interest in the same, in a manner and under circumstances that are not inconsistent with the provisions of this Bond Indenture. No party relying upon an instrument executed by the Bond Trustee as provided in this Article VIII shall be bound to ascertain the Bond Trustee's authority, inquire into the satisfaction of any conditions precedent or see to the application of any moneys.

(c) The Bond Trustee shall, at such time as there are no Bonds Outstanding and all sums payable by the Bond Issuer to the Bond Trustee under this Bond Indenture have been paid, release any remaining portion of the Collateral that secured the Bonds from the Lien of this Bond Indenture and release to the Bond Issuer or any other Person entitled thereto any funds then on deposit in the Collection Account. The Bond Trustee shall release property from the Lien of this Bond Indenture pursuant to this Section 8.04(c) only upon receipt of an Issuer Request accompanied by an Officer's Certificate and an Opinion of Counsel.

Section 8.05. Opinion of Counsel.

The Bond Trustee shall receive at least seven (7) days' notice when requested by the Bond Issuer to take any action pursuant to Section 8.04(b), accompanied by copies of any instruments involved, and the Bond Trustee shall also require, as a condition to such action, an Opinion of Counsel, in form and substance reasonably satisfactory to the Bond Trustee, stating the legal effect of any such action, outlining the steps required to complete the same, and concluding that all conditions precedent to the taking of such action have been complied with and such action will not materially and adversely impair the security for the Bonds or the rights of the Bondholders in contravention of the provisions of this Bond Indenture; provided, however, that such Opinion of Counsel shall not be required to express an opinion as to the fair value of the Collateral. Counsel rendering any such opinion may rely, without independent investigation, on the accuracy and validity of any certificate or other instrument delivered to the Bond Trustee in connection with any such action.

Section 8.06. Reports by Independent Registered Accountants.

As of the Issuance Date, the Bond Issuer shall appoint a firm of Independent registered public accountants of recognized national reputation for purposes of preparing and delivering the reports or certificates of such accountants required by this Bond Indenture. Upon any resignation by such firm the Bond Issuer shall provide written notice thereof to the Bond Trustee and shall promptly appoint a successor thereto that shall also be a firm of Independent registered public accountants of recognized national reputation. If the Bond Issuer shall fail to appoint a successor to a firm of Independent registered public accountants that has resigned within fifteen (15) days after such resignation, the Bond Trustee shall promptly notify the Bond Issuer of such failure in writing. If the Bond Issuer shall not have appointed a successor within ten (10) days thereafter the Bond Trustee shall promptly appoint a successor firm of Independent registered public accountants of recognized national reputation; provided, however, that the Bond Trustee shall have no liability with respect to such appointment if the Bond Trustee acted with due care with respect thereto. The fees of such Independent registered public accountants and its successor shall be payable by the Bond Issuer.

## ARTICLE IX
Supplemental Bond Indentures

Section 9.01. Supplemental Bond Indentures Without Consent of Bondholders.

(a) Without the consent of the Holders of any Bonds but with prior notice to the Rating Agencies, the Bond Issuer and the Bond Trustee, when authorized by an Issuer Order, at any time and from time to time, may enter into one or more indentures supplemental hereto, in form reasonably satisfactory to the Bond Trustee, for any of the following purposes:

(i) to correct or amplify the description of any property, including without limitation the Collateral, at any time subject to the Lien of this Bond Indenture, or better to assure, convey and confirm unto the Bond Trustee any property subject or required to be subjected to the Lien of this Bond Indenture, or to subject to the Lien of this Bond Indenture additional property;

(ii) to evidence the succession, in compliance with the applicable provisions hereof, of another person to the Bond Issuer, and the assumption by any such successor of the covenants of the Bond Issuer herein and in the Bonds contained;

(iii) to add to the covenants of the Bond Issuer, for the benefit of the Holders of the Bonds, or to surrender any right or power herein conferred upon the Bond Issuer;

(iv) to convey, transfer, assign, mortgage or pledge any property to or with the Bond Trustee;

(v) to cure any ambiguity, to correct or supplement any provision herein or in any supplemental bond indenture which may be inconsistent with any other provision herein or in any supplemental bond indenture or to make any other provisions with respect to matters or questions arising under this Bond Indenture or in any supplemental bond indenture; provided, however, that such action shall not adversely affect the interests of the Holders of the Bonds;

(vi) to evidence and provide for the acceptance of the appointment hereunder by a successor trustee with respect to the Bonds and to add to or change any of the provisions of this Bond Indenture as shall be necessary to facilitate the administration of the trusts hereunder by more than one trustee, pursuant to the requirements of Article VI; or

(vii) to modify, eliminate or add to the provisions of this Bond Indenture to such extent as shall be necessary to effect the qualification of this Bond Indenture under the Trust Indenture Act or under any similar federal statute hereafter enacted and to add to this Bond Indenture such other provisions as may be expressly required by the Trust Indenture Act.

(viii) to qualify the Bonds of any Tranche for listing on a securities exchange or registration with a Clearing Agency; or

(ix) to satisfy any Rating Agency requirements or criteria or to maintain, or improve upon, the existing ratings on the Bonds.

The Bond Trustee is hereby authorized to join in the execution of any such supplemental bond indenture and to make any further appropriate agreements and stipulations that may be therein contained.

(b) The Bond Issuer and the Bond Trustee, when authorized by an Issuer Order, may, also without the consent of any of the Holders of the Bonds, enter into an indenture or indentures supplemental hereto for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of, this Bond Indenture or of modifying in any manner the rights of the Holders of the Bonds under this Bond Indenture; provided, however, that (i) such action shall not, as evidenced by an Officer's Certificate, adversely affect in any material respect the interests of the Bondholders and (ii) the Rating Agency Condition shall have been satisfied with respect thereto.

Section 9.02. Supplemental Bond Indentures with Consent of Bondholders.

The Bond Issuer and the Bond Trustee, when authorized by an Issuer Order, also may, with prior notice to the Rating Agencies and with the consent of the Holders of not less than a majority of the Outstanding Amount of the Bonds of each Tranche to be affected, by Act of such Holders delivered to the Bond Issuer and the Bond Trustee, enter into an indenture or indentures supplemental hereto for the purpose of adding any provisions to, or changing in any manner or eliminating any of the provisions of, this Bond Indenture or of modifying in any manner the rights of the Holders of the Bonds under this Bond Indenture; provided, however, that no such supplemental bond indenture shall, without the consent of the Holder of each Outstanding Bond of each Tranche affected thereby:

(i) change the date of payment of any installment of principal of or interest on any Bond, or reduce the principal amount thereof or the interest rate thereon, change the provisions of this Bond Indenture relating to the application of collections on, or the proceeds of the sale of, the Collateral to payment of principal of or interest on the Bonds, or change any place of payment where, or the coin or currency in which, any Bond or the interest thereon is payable, or impair the right to institute suit for the enforcement of the provisions of this Bond Indenture requiring the application of funds available therefor, as provided in Article V, to the payment of any such amount due on the Bonds on or after the respective due dates thereof;

(ii) reduce the percentage of the Outstanding Amount of the Bonds or of a Tranche thereof, the consent of the Holders of which is required for any such supplemental bond indenture, or the consent of the Holders of which is required for any waiver of compliance with certain provisions of this Bond Indenture or certain defaults hereunder and their consequences provided for in this Bond Indenture;

(iii) modify or alter the provisions of the proviso to the definition of the term "Outstanding";

(iv) reduce the percentage of the Outstanding Amount of the Bonds required to direct the Bond Trustee to direct the Bond Issuer to sell or liquidate the Collateral pursuant to Section 5.04;

(v) modify any provision of this Section 9.02 except to increase any percentage specified herein or to provide that certain additional provisions of this Bond Indenture or the other Basic Documents cannot be modified or waived without the consent of the Holder of each Outstanding Bond affected thereby;

(vi) modify any of the provisions of this Bond Indenture in such manner as to affect the calculation of the amount of any payment of interest or principal due on any Bond on any Payment Date (including the calculation of any of the individual components of such calculation) or change the Expected Amortization Schedules, Expected Sinking Fund Schedule or Final Maturity Dates of any Tranche of Bonds;

(vii) decrease the Required Operating Reserve Level or the Required Debt Service Reserve Level;

(viii) modify the provisions of this Bond Indenture regarding the voting of the Bonds held by the Bond Issuer, the Servicer or any Affiliate of any of the foregoing Persons;

(ix) decrease the percentage of the aggregate principal amount of Bonds or affected Tranche required to amend the sections of this Bond Indenture which specify applicable percentages of the aggregate principal amount of the Bonds necessary to amend any Basic Document;

(x) cause a violation of Section 3.14; or

(xi) permit the creation of any Lien ranking prior to or on a parity with the Lien of this Bond Indenture with respect to any part of the Collateral, other than as contemplated by Section 2.17, or, except as otherwise permitted or contemplated herein, terminate the Lien of this Bond Indenture on any property at any time subject hereto or deprive the Holder of any Bond of the security provided by the Lien of this Bond Indenture.

The Bond Trustee may in its discretion determine whether or not any Bonds of a Tranche would be affected by any supplemental bond indenture and any such determination shall be conclusive upon the Holders of all Bonds of such Tranche, whether theretofore or thereafter authenticated and delivered hereunder. The Bond Trustee shall not be liable for any such determination made in good faith.

It shall not be necessary for any Act of Bondholders under this Section 9.02 to approve the particular form of any proposed supplemental bond indenture, but it shall be sufficient if such Act shall approve the substance thereof.

Promptly after the execution by the Bond Issuer and the Bond Trustee of any supplemental bond indenture pursuant to this Section 9.02, the Bond Issuer shall send or cause to be sent to the Rating Agencies and the Holders of the Bonds to which such amendment or supplemental bond indenture relates either a copy of such supplemental bond indenture or a notice setting forth in general terms the substance of such supplemental bond indenture. Any failure of the Bond Trustee to send such copy or notice, or any defect therein, shall not, however, in any way impair or affect the validity of any such supplemental bond indenture.

Section 9.03. Execution of Supplemental Bond Indentures.

In executing any supplemental bond indenture permitted by this Article IX or the modifications thereby of the trusts created by this Bond Indenture, the Bond Trustee shall be entitled to receive, and subject to Sections 6.01 and 6.02, shall be fully protected in relying upon, an Opinion of Counsel stating that the execution of such supplemental bond indenture is authorized or permitted by this Bond Indenture. The Bond Trustee may, but shall not be obligated to, enter into any such supplemental bond indenture that affects the Bond Trustee's own rights, duties, liabilities or immunities under this Bond Indenture or otherwise.

Any supplemental bond indenture shall be accompanied by an Opinion of Counsel to the effect that it does not adversely affect the exclusion of interest on the Bonds from gross income for federal income tax purposes.

Section 9.04. Effect of Supplemental Bond Indenture.

Upon the execution of any supplemental bond indenture pursuant to the provisions hereof, this Bond Indenture shall be and be deemed to be modified and amended in accordance therewith with respect to each Tranche of Bonds affected thereby, and the respective rights, limitations of rights, obligations, duties, liabilities and immunities under this Bond Indenture of the Bond Trustee, the Bond Issuer and the Holders of the Bonds shall thereafter be determined, exercised and enforced hereunder subject in all respects to such modifications and amendments, and all the terms and conditions of any such supplemental bond indenture shall be and be deemed to be part of the terms and conditions of this Bond Indenture for any and all purposes. If required by the Bond Trustee, Bonds may bear a notation in form approved by the Bond Trustee as to any matter provided for in such supplemental bond indenture. If the Bond Issuer or the Bond Trustee shall so determine, new Bonds so modified as to conform, in the opinion of the Bond Trustee and the Bond Issuer, to any such supplemental bond indenture may be prepared and executed by the Bond Issuer and authenticated and delivered by the Bond Trustee in exchange for Outstanding Bonds.

## ARTICLE X
Redemption of Bonds

Section 10.01. Redemption by Bond Issuer.

This Bond Indenture does not permit redemption of Bonds prior to maturity under any circumstances, except as required by Section 2.02(e) and as permitted by 2.02(f), and in each case pursuant to this Article X.

Section 10.02. Privilege of Redemption and Redemption Price.

Bonds of a Tranche subject to redemption prior to maturity shall be redeemable, upon notice as provided in this Article X, at the times and at the Redemption Prices specified in Section 2.02(e) and Section 2.02(f).

Section 10.03. Redemption at the Direction of the Bond Issuer.

In the case of any redemption of Bonds at the direction of the Bond Issuer, the Bond Issuer shall give written notice to the Bond Trustee of its direction so to redeem, of the redemption date, of the Tranche and of the principal amounts of the Bonds of each maturity of such Tranche and of the Bonds of each interest rate within a maturity to be redeemed (which Tranche, maturities and principal amounts thereof to be redeemed shall be determined by the Bond Issuer in its sole discretion, subject to any limitations with respect thereto contained in this Bond Indenture). Such notice shall be given at least 45 days prior to the redemption date or such shorter period as shall be acceptable to the Bond Trustee. In the event notice of redemption shall have been provided pursuant to Section 10.06, there shall be paid prior to the redemption date to the appropriate Paying Agent an amount in cash which, in addition to other moneys, if any, available therefor held by such Paying Agent, will be sufficient to redeem on the redemption date at the Redemption Price thereof, plus interest accrued and unpaid to the redemption date, all of the Bonds to be redeemed. The Bond Issuer shall promptly notify the Bond Trustee in writing of all such payments by it to a Paying Agent other than the Bond Trustee.

Section 10.04. Redemption Otherwise Than at the Bond Issuer's Direction.

Whenever by the terms of this Bond Indenture the Bond Trustee is required or authorized to redeem Bonds otherwise than at the direction of the Bond Issuer, the Bond Trustee shall (i) select the Bonds to be redeemed, (ii) give the notice of redemption for and on behalf of and at the expense of the Bond Issuer, and (iii) pay out of moneys available therefor the Redemption Price thereof, plus interest accrued and unpaid to the redemption date, to the appropriate Paying Agents in accordance with the terms of this Article X.

Section 10.05. Selection of Bonds to be Redeemed.

If fewer than all of the Bonds of like Tranche shall be called for prior redemption, the particular Bonds or portions of Bonds to be redeemed shall be selected by the Bond Trustee in such manner as the Bond Trustee in its discretion may deem fair and appropriate; provided, however, that for any Bond of a denomination of more than the Minimum Denomination, the portion of such Bond to be redeemed shall be in a principal amount equal to such Minimum Denomination, and that, in selecting portions of such Bonds for redemption, the Bond Trustee shall treat each such Bond as representing that number of Bonds of such Minimum Denomination which is obtained by dividing the principal amount of such Bond to be redeemed in part by the amount of such Minimum Denomination.

Section 10.06. Notice of Redemption.

(a) When the Bond Trustee shall receive notice from the Bond Issuer of its election or direction to redeem Bonds pursuant to Section 10.03, and when redemption of Bonds is authorized or required pursuant to Section 10.04, the Bond Trustee shall give notice, in the name of, on behalf of and at the expense of the Bond Issuer, of the redemption of such Bonds, which notice shall specify the Series, CUSIP number, if any, maturities and interest rates within maturities, if any, of the Bonds to be redeemed, the redemption date and the place or places where amounts due upon such redemption will be payable and, if fewer than all of the Bonds of any like Tranche, maturity and interest rate within maturities are to be redeemed, the letters and numbers or other distinguishing marks of such Bonds so to be redeemed, and, in the case of Bonds to be redeemed in part only, such notice shall also specify the respective portions of the principal amount thereof to be redeemed. Such notice shall further state that on such date there shall become due and payable upon each Bond to be redeemed the Redemption Price thereof, or the Redemption Price of the specified portions of the principal thereof in the case of Bonds to be redeemed in part only, together with interest accrued to the redemption date, and that from and after such date interest thereon shall cease to accrue and be payable, subject to Section 10.06(b) below. Such notice shall be mailed by the Bond Trustee, postage prepaid, not less than 30 days before the redemption date, to the Registered Holders of any Bonds or portions of Bonds which are to be redeemed, at their last addresses, if any, appearing upon the Bond Register, subject to Section 2.16(b), and also promptly shall be given to the Rating Agencies.

(b) Any notice of optional redemption of Bonds may state that it is conditional in whole or in part upon receipt by the Bond Trustee of moneys sufficient to pay the Redemption Price together with accrued interest to the redemption date, or upon the satisfaction of any other condition, or that it may be rescinded upon the occurrence of any other event, and any conditional notice so given may be rescinded if and to the extent any such other event occurs. Notice of such rescission, failure to fund the Redemption Price or satisfaction of such other condition shall be given by the Bond Trustee to affected Registered Holders of such Bonds as promptly as practicable upon the failure of such condition or the occurrence of such other event, in the same manner as the conditional notice of redemption was given.

(c) Failure of the Registered Holder of any Bond which is to be redeemed to receive any notice given pursuant to subsection (a) or (b) of this Section 10.06 shall not affect the sufficiency or validity of the proceedings contemplated thereby.

Section 10.07. Payment of Redeemed Bonds.

Notice having been given in the manner provided in Section 10.06, the Bonds or portions thereof so called for redemption shall become due and payable on the redemption date so designated at the Redemption Price, plus interest accrued and unpaid to the redemption date, and, if presentation and surrender thereof are required hereby, upon presentation and surrender thereof at the office specified in such notice, such Bonds or portions thereof shall be paid at the Redemption Price plus interest accrued and unpaid to the redemption date. If there shall be drawn for redemption less than all of a Bond, if presentation and surrender thereof are required hereby, the Bond Issuer shall execute and the Bond Trustee shall authenticate and the Paying Agent shall deliver, upon the surrender of such Bond, without charge to the owner thereof, for the unredeemed balance of the principal amount of the Bonds so surrendered, at the option of the owner thereof, Bonds of like Tranche, maturity and interest rate in any of the authorized denominations. If, on the redemption date, moneys for the redemption of all the Bonds or portions thereof of any like Tranche, maturity, or of like interest rate within a maturity, to be redeemed, together with interest to the redemption date, shall be held by the Paying Agents so as to be available therefor on said date and if notice of redemption shall have been given as aforesaid, then, from and after the redemption date interest on the Bonds or portions thereof of such Series, maturity and interest rate so called for redemption shall cease to accrue and become payable. If said moneys shall not be so available on the redemption date, such Bonds or portions thereof shall continue to bear interest until paid at the same rate as they would have borne had they not been called for redemption.

# ARTICLE XI
Miscellaneous

Section 11.01. Form of Documents Delivered to Bond Trustee.

In any case where several matters are required to be certified by, or covered by an opinion of, any specified Person, it is not necessary that all such matters be certified by, or covered by the opinion of, only one such Person, or that they be so certified or covered by only one document, but one such Person may certify or give an opinion with respect to some matters and one or more other such Persons as to other matters, and any such Person may certify or give an opinion as to such matters in one or several documents.

Any certificate or opinion of an Authorized Officer of the Bond Issuer may be based, insofar as it relates to legal matters, upon a certificate or opinion of, or representations by, counsel, unless such officer knows, or in the exercise of reasonable care should know, that the certificate or opinion or representations with respect to the matters upon which his or her certificate or opinion is based are erroneous. Any such certificate of an Authorized Officer or Opinion of Counsel may be based, insofar as it relates to factual matters, upon a certificate or opinion of, or representations by, an officer or officers of the Servicer, the Seller, the Bond Issuer or the Administrator, stating that the information with respect to such factual matters is in the possession of the Servicer, the Seller, the Bond Issuer or the Administrator, unless such counsel knows, or in the exercise of reasonable care should know, that the certificate or opinion or representations with respect to such matters are erroneous.

Whenever in this Bond Indenture, in connection with any application or certificate or report to the Bond Trustee, it is provided that the Bond Issuer shall deliver any document as a condition of the granting of such application, or as evidence of the Bond Issuer's compliance with any term hereof, it is intended that the truth and accuracy, at the time of the granting of such application or at the effective date of such certificate or report (as the case may be), of the facts and opinions stated in such document shall in such case be conditions precedent to the right of the Bond Issuer to have such application granted or to the sufficiency of such certificate or report. The foregoing shall not, however, be construed to affect the Bond Trustee's right to rely upon the truth and accuracy of any statement or opinion contained in any such document as provided in Article VI.

Where any Person is required to make, give or execute two or more applications, requests, consents, certificates, statements, opinions or other instruments under this Bond Indenture, they may, but need not, be consolidated and form one instrument.

Section 11.02. Notices.

(a) Unless otherwise specifically provided herein, all notices, directions, consents and waivers required under the terms and provisions of this Bond Indenture shall be in English and in writing, and any such notice, direction, consent or waiver may be given by United States mail, courier service, facsimile transmission or electronic mail (confirmed by telephone, United States mail or courier service in the case of notice by facsimile transmission or electronic mail) or any other customary means of communication, and any such notice, direction, consent or waiver shall be effective when delivered, or if mailed, three (3) days after deposit in the United States mail with proper postage for ordinary mail prepaid, if to the Bond Issuer, to:

Utility Debt Securitization Authority
c/o LIPA, as Administrator
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: ____@lipower.org

if to the Bond Trustee, to:

The Bank of New York Mellon
101 Barclay Street - Floor 7-W
New York, New York 10286
Attention: Frederic Belen
Telephone: (212) 815-2588
Telecopy: (732) 667-9205
Email: frederic.belen@bnymellon.com

if to the Rating Agencies, to:

Standard & Poor’s Ratings Services
55 Water Street
New York, New York 10041
Attention: Structured Credit Surveillance
Telephone: 212-438-8991
E-mail: servicer-report@standardandpoors.com

and

Moody’s Investors Service, Inc.
25th Floor, 7 World Trade Center, 250 Greenwich Street
New York, New York 10007
Attention: ABS/RMBS Monitoring Department
E-mail: ServicerReports@moodys.com

and

Fitch Ratings
33 Whitehall Street
New York, New York 10004
Attention: ABS Surveillance
Telephone: 212-908-0500
E-mail: surveillance-abs-other@fitchratings.com

or in each case at such other address as shall be designated to the Bond Issuer and the Bond Trustee.

Section 11.03. Effect of Headings and Table of Contents.

The Article and Section headings herein and the Table of Contents are for convenience only and shall not affect the construction hereof.

Section 11.04. Successors and Assigns.

All covenants and agreements in this Bond Indenture and the Bonds by the Bond Issuer shall bind its successors and assigns, whether so expressed or not. All agreements of the Bond Trustee in this Bond Indenture shall bind its successors.

Section 11.05. Severability.

In case any provision in this Bond Indenture or in the Bonds shall be invalid, illegal or unenforceable, the validity, legality, and enforceability of the remaining provisions shall not in any way be affected or impaired thereby.

Section 11.06. Benefits of Bond Indenture.

Nothing in this Bond Indenture or in the Bonds, express or implied, shall give to any Person, other than the parties hereto and their successors hereunder, and the Bondholders, and any other party secured hereunder, and any other Person with an ownership interest in any part of the Collateral, any benefit or any legal or equitable right, remedy or claim under this Bond Indenture.

Section 11.07. Legal Holidays.

In any case where the date on which any payment is due shall not be a Business Day, then (notwithstanding any other provision of the Bonds or this Bond Indenture) payment need not be made on such date, but may be made on the next succeeding Business Day with the same force and effect as if made on the date on which nominally due, and no interest shall accrue for the period from and after any such nominal date. In any case where the last date for performance of any act or the exercising of any right, as provided in this Bond Indenture, is not a Business Day, such act may be performed and such right may be exercised on the next succeeding Business Day, with the same force and effect as if done on the date on which nominally required.

Section 11.08. Governing Law.

THIS BOND INDENTURE SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REFERENCE TO ITS CONFLICT OF LAW PROVISIONS, AND THE OBLIGATIONS, RIGHTS AND REMEDIES OF THE PARTIES HEREUNDER SHALL BE DETERMINED IN ACCORDANCE WITH SUCH LAWS.

Section 11.09. Counterparts.

This Bond Indenture may be executed in any number of counterparts, each of which so executed shall be deemed to be an original, but all such counterparts shall together constitute but one and the same instrument.

Section 11.10. No Recourse to Trustees, Etc., and Shareholders, Etc.

No recourse may be taken, directly or indirectly, with respect to the obligations of the Bond Issuer or the Bond Trustee on the Bonds or under this Bond Indenture or any certificate or other writing delivered in connection herewith or therewith, against (i) any trustee, director, officer, employee, agent or attorney of the Bond Issuer or (ii) any shareholder, partner, owner, beneficiary, agent, officer, director or employee of the Bond Trustee. Each Bondholder by accepting a Bond specifically confirms the non-recourse nature of these obligations and waives and releases all such liability. These waivers and releases are part of the consideration for issuance of the Bonds.

Section 11.11. No Recourse to Bond Issuer, Authority or LIPA.

Notwithstanding any provision of this Bond Indenture or any supplemental bond indenture to the contrary, Bondholders and the Bond Trustee shall have no recourse to the credit or any assets of the Authority, LIPA or the Bond Issuer (other than, in the case of the Bond Issuer, the Collateral), but shall look only to the Collateral, with respect to any amounts due to the Bondholders hereunder and under the Bonds and to the Bond Trustee. Each Bondholder by accepting a Bond, and the Bond Trustee, specifically confirms the non-recourse nature of these obligations and waives and releases all such liability. These waivers and releases are part of the consideration for issuance of the Bonds.

Section 11.12. Inspection.

The Bond Issuer agrees that, on reasonable prior notice, it will permit any representative of the Bond Trustee, during the Bond Issuer's normal business hours, to examine all the books of account, records, reports, and other papers of the Bond Issuer, to make copies and extracts therefrom, to cause such books to be audited by Independent certified public accountants, and to discuss the Bond Issuer's affairs, finances and accounts with the Bond Trustee's officers, employees, and Independent certified public accountants, all at such reasonable times and as often as may be reasonably requested. The Bond Trustee shall and shall cause its representatives to hold in confidence all such information except to the extent disclosure may be required by law (and all reasonable applications for confidential treatment are unavailing) and except to the extent that the Bond Trustee may reasonably determine that such disclosure is consistent with its obligations hereunder. Notwithstanding anything herein to the contrary, the foregoing shall not be construed to prohibit (i) disclosure of any and all information that is or becomes publicly known, or information obtained by the Bond Trustee from sources other than the Bond Issuer, provided such parties are rightfully in possession of such information and do not have an obligation of confidentiality, (ii) disclosure of any and all information (A) if required to do so by any applicable LIPA Reform Act, law, rule or regulation, (B) pursuant to any subpoena, civil investigative demand or similar demand or regulatory authority exercising its proper jurisdiction, (C) in any preliminary or final official statement, or contract or other document pertaining to the transactions contemplated by this Bond Indenture or the other Basic Documents approved in advance by the Bond Issuer or (D) to any affiliate, independent or internal auditor, agent, employee or attorney of the Bond Trustee having a need to know the same, provided that such parties agree to be bound by the confidentiality provisions contained in this Section 11.12, or (iii) any other disclosure authorized by the Bond Issuer.

Section 11.13. Trustee Capacity.

Each of the Bondholders by accepting the Bonds shall be deemed to acknowledge and consent to The Bank of New York Mellon acting in the capacity of Bond Trustee.

Section 11.14. Waiver of Jury Trial.

EACH OF THE BOND ISSUER AND THE BOND TRUSTEE HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS BOND INDENTURE, THE BONDS OR THE TRANSACTIONS CONTEMPLATED HEREBY.

Section 11.15. Rule 17g-5 Compliance.

(a) The Bond Trustee agrees that any notice, report, request for satisfaction of the Rating Agency Condition, document or other information provided by the Bond Trustee to any Rating Agency under this Bond Indenture or any other Basic Document to which it is a party for the purpose of determining the initial credit rating of the Bonds or undertaking credit rating surveillance of the Bonds shall be provided, substantially concurrently, to the Servicer for posting on a password-protected website (the "17g-5 Website"). The Servicer shall be responsible for posting all of the information on the 17g-5 Website.

(b) The Bond Trustee will not be responsible for creating or maintaining the 17g-5 Website, posting any information to the 17g-5 Website or assuring that the 17g-5 Website complies with the requirements of this Bond Indenture, Rule 17g-5 or any other law or regulation. In no event shall the Bond Trustee be deemed to make any representation in respect of the content of the 17g-5 Website or compliance by the 17g-5 Website with this Bond Indenture, Rule 17g-5 or any other law or regulation. The Bond Trustee shall have no obligation to engage in or respond to any oral communications with respect to the transactions contemplated hereby, any transaction documents relating hereto or in any way relating to the Bonds or for the purposes of determining the initial credit rating of the Bonds or undertaking credit rating surveillance of the Bonds with any Rating Agency or any of its respective officers, directors or employees. The Bond Trustee shall not be responsible or liable for the dissemination of any identification numbers or passwords for the 17g-5 Website, including by the Servicer, the Rating Agencies, a nationally recognized statistical rating organization ("NRSRO"), any of their respective agents or any other party. Additionally, the Bond Trustee shall not be liable for the use of the information posted on the 17g-5 Website, whether by the Servicer, the Rating Agencies, an NRSRO or any other third party that may gain access to the 17g-5 Website or the information posted thereon.

[Balance of Page Intentionally Left Blank;
Signature Page Follows]

IN WITNESS WHEREOF, the Bond Issuer and the Bond Trustee have caused this Bond Indenture to be duly executed by their respective officers, thereunto duly authorized, all as of the day and year first above written.

UTILITY DEBT SECURITIZATION AUTHORITY,
as Bond Issuer,

By:________________________________________
Name: ____________
Title: Chief Financial Officer

THE BANK OF NEW YORK MELLON,
as Bond Trustee

By:________________________________________
Name: Joseph M. Lawlor
Title: Vice President

EXHIBIT A
FORM OF BOND

REGISTERED NO. [ ] $[ ]

UNLESS AND UNTIL IT IS EXCHANGED IN WHOLE OR IN PART FOR SECURITIES IN DEFINITIVE REGISTERED FORM, THIS SECURITY MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY THE CLEARING AGENCY TO THE NOMINEE OF THE CLEARING AGENCY OR BY A NOMINEE OF THE CLEARING AGENCY TO THE CLEARING AGENCY OR ANOTHER NOMINEE OF THE CLEARING AGENCY OR BY THE CLEARING AGENCY OR ANY SUCH NOMINEE TO A SUCCESSOR CLEARING AGENCY OR A NOMINEE OF SUCH SUCCESSOR CLEARING AGENCY. UNLESS THIS SECURITY IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY, A NEW YORK CORPORATION ("DTC"), TO THE ISSUER OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND ANY SECURITY ISSUED IS REGISTERED IN THE NAME OF CEDE & CO. OR IN SUCH OTHER NAME AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC (AND ANY PAYMENT IS MADE TO CEDE & CO. OR TO SUCH OTHER ENTITY AS IS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF DTC), ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL INASMUCH AS THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

THE PRINCIPAL OF THIS BOND WILL BE PAID IN INSTALLMENTS AS SET FORTH HEREIN. ACCORDINGLY, THE OUTSTANDING PRINCIPAL AMOUNT OF THIS BOND AT ANY TIME MAY BE LESS THAN THE AMOUNT SHOWN ON THE FACE HEREOF. THE HOLDER OF THIS BOND HAS NO RECOURSE TO THE BOND ISSUER HEREOF AND AGREES TO LOOK ONLY TO THE COLLATERAL, AS DESCRIBED IN THE BOND INDENTURE, FOR PAYMENT OF ANY AMOUNTS DUE HEREUNDER. ALL OBLIGATIONS OF THE BOND ISSUER OF THIS BOND UNDER THE TERMS OF THE BOND INDENTURE WILL BE RELEASED AND DISCHARGED UPON PAYMENT IN FULL HEREOF OR AS OTHERWISE PROVIDED IN THE BOND INDENTURE.

NEITHER THE FULL FAITH AND CREDIT NOR THE TAXING POWER OF THE STATE OF NEW YORK IS PLEDGED TO THE PAYMENT OF THE PRINCIPAL OF, OR INTEREST ON, THIS BOND.

RESTRUCTURING BONDS

Series 2022 __

TRANCHE [ - ] BOND

| Interest Rate | Final Maturity Date | Original Cusip |
|---|---|---|
| [ ]% | | |

Original Principal Amount:

Utility Debt Securitization Authority, a special purpose corporate municipal instrumentality, body corporate and politic, political subdivision and public benefit corporation of the State of New York (herein referred to as the "Bond Issuer"), for value received, hereby promises to pay to

[__________________________], or registered assigns, the Original Principal Amount shown above in semiannual installments on the Payment Dates and in the amounts specified in the Bond Indenture hereinafter mentioned or, if less, the amounts determined pursuant to Section 8.02 of the Bond Indenture, in each year, commencing on the date determined pursuant to Section 2.02 of the Bond Indenture and ending on or before the Final Maturity Date (if this Bond has a Final Maturity Date on and after December 15, 203_, subject to redemption prior to maturity as described below) and to pay interest on the principal amount of this Bond, at the Interest Rate shown above, on each June 15 and December 15, commencing on [June 15, 2023], or if any such day is not a Business Day, the next succeeding Business Day, and continuing until the earlier of the payment of the principal hereof or the Final Maturity Date (each a "Payment Date"). Interest on this Bond will accrue for each Payment Date from the most recent Payment Date on which interest has been paid to but excluding such Payment Date or, if no interest has yet been paid, from September __, 2022. Interest will be computed on the basis of a 360-day year of twelve 30-day months.

The principal of and interest on this Bond are payable in such coin or currency of the United States of America as at the time of payment is legal tender for payment of public and private debts. All payments made by the Bond Issuer with respect to this Bond shall be applied first to interest due and payable on this Bond as provided above and then to the unpaid principal of this Bond, all in the manner set forth in Section 8.02 of the Bond Indenture.

This Bond is one of a duly authorized issue of Bonds of the Bond Issuer, designated as its Restructuring Bonds, Series 2022 (herein called the "Bonds"), issuable in one or more Series and Tranches, and further designated as a Tranche [ - ] Bond (collectively with all other Tranche [ - ] Bonds of this Series, the "Tranche [ - ] Bonds" or the "Bonds of this Tranche"), all issued or to be issued under a Bond Indenture dated as of September __, 2022 (the "Bond Indenture"), between the Bond Issuer and The Bank of New York Mellon, as Bond Trustee (the "Bond Trustee," which term includes any successor trustee under the Bond Indenture), to which Bond Indenture and all indentures supplemental thereto reference is hereby made for a statement of the respective rights and obligations thereunder of the Bond Issuer, the Bond Trustee and the Holders of the Bonds. All terms used in this Bond that are defined in the Bond Indenture, as supplemented or amended, shall have the meanings assigned to them in the Bond Indenture, as supplemented or amended.

The Bonds of this Tranche and the other Series and Tranches of Bonds issued and to be issued by the Bond Issuer under the Bond Indenture are and will be equally and ratably secured by the Collateral, as provided in the Bond Indenture.

***Neither the full faith and credit nor the taxing power of the State of New York is pledged to the payment of the principal of, or interest on, this Bond.***

The principal of this Bond shall be payable on each Payment Date only to the extent that amounts in the Collection Account are available therefor, and only until the outstanding principal balance thereof on such Payment Date (after giving effect to all payments of principal, if any, made on such Payment Date) has been reduced to the principal balance specified in the Expected Amortization Schedule or Expected Sinking Fund Schedule, as applicable, which is included in Section 2.02 of the Bond Indenture, unless payable earlier either because an Event of Default shall have occurred and be continuing and the Bond Trustee or the Holders of Bonds representing not less than a majority of the Outstanding Amount of the Bonds have declared the Bonds to be immediately due and payable in accordance with Section 5.02 of the Bond Indenture (unless such declaration shall have been rescinded and annulled in accordance with Section 5.02 of the Bond Indenture) or, if this Bond is subject to optional redemption prior to maturity, because this Bond has been redeemed prior to maturity. However, actual principal payments may be made in lesser than expected amounts and at later than expected times as determined pursuant to

Section 8.02 of the Bond Indenture. The entire unpaid principal amount of this Bond shall be due and payable on the Final Maturity Date hereof. Notwithstanding the foregoing, the entire unpaid principal amount of the Bonds shall be due and payable, if not then previously paid, on the date on which an Event of Default shall have occurred and be continuing and the Bond Trustee or the Holders of the Bonds representing not less than a majority of the Outstanding Amount of the Bonds have declared the Bonds to be immediately due and payable in the manner provided in Section 5.02 of the Bond Indenture (unless such declaration shall have been rescinded and annulled in accordance with Section 5.02 of the Indenture). All principal payments on the Bonds of this Tranche shall be made pro rata to the Holders of the Bonds of this Tranche entitled thereto based on the respective principal amounts of the Bonds of this Tranche held by them.

Payments of interest on this Bond due and payable on each Payment Date, together with the installment of principal shall be made by check mailed first-class, postage prepaid, to the Person whose name appears as the Registered Holder of this Bond (or one or more Predecessor Bonds) on the Bond Register as of the close of business on the Record Date, except that (i) upon application to the Bond Trustee by any Holder owning Bonds in the principal amount of $10,000,000 or more not later than the applicable Record Date, payment will be made by wire transfer to an account maintained by such Holder and (ii) if this Bond is a Book-Entry Bond, payments will be made by wire transfer in immediately available funds to the account designated by the Holder of this Bond unless and as required by the operational rules and procedures of the Clearing Agency until such Bond is exchanged for Definitive Bonds (in which event payments shall be made as provided above), and except for the final installment of principal payable with respect to this Bond on a Payment Date which shall be payable as provided below. Such checks shall be mailed to the Person entitled thereto at the address of such Person as it appears on the Bond Register as of the applicable Record Date without requiring that this Bond be submitted for notation of payment. Any reduction in the principal amount of this Bond (or any one or more Predecessor Bonds) effected by any payments made on any Payment Date shall be binding upon all future Holders of this Bond and of any Bond issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not noted hereon. If funds are expected to be available, as provided in the Bond Indenture, for payment in full of the then remaining unpaid principal amount of this Bond on a Payment Date, then the Bond Trustee, in the name of and on behalf of the Bond Issuer, will notify the Person who was the Registered Holder hereof as of the Record Date preceding such Payment Date by notice mailed no later than five days prior to such final Payment Date and shall specify that such final installment will be payable only upon presentation and surrender of this Bond and shall specify the place where this Bond may be presented and surrendered for payment of such installment.

The Bond Issuer shall pay interest on overdue installments of interest at the Bond Interest Rate to the extent lawful.

If this Bond is part of Tranche __ through Tranche __ of the Bonds it shall be subject to redemption from time to time prior to maturity from Sinking Fund Payments at a Redemption Price of 100% of the principal amount of such Tranche of the Bonds to be redeemed. Unless an Event of Default shall have occurred and be continuing and the unpaid principal amount of all Bonds and accrued interest thereon has been declared to be due and payable, on each Payment Date, the Bond Trustee shall redeem such Tranche of the Bonds prior to maturity and pay to the Registered Holders amounts payable pursuant to Section 8.02(e) as a Sinking Fund Payment until the Outstanding Amount of such Tranche of the Bonds has been reduced to zero; provided, however, that any payment that reduces the Outstanding Amount to zero shall be applied as a payment of a maturity of such Tranche of the Bonds and not as a redemption prior to maturity; provided further, however, that no Sinking Fund Payment shall be made prior to the first Scheduled Sinking Fund Redemption Date specified in the Expected Sinking Fund Schedule included in Section 2.02 of the Bond Indenture and on any Payment Date in an amount that reduces the Outstanding Amount of such Tranche of the Bonds below the Minimum Remaining

Outstanding Amount specified in the Expected Sinking Fund Schedule included in Section 2.02 of the Bond Indenture; and provided further, however, that any Bonds of such Tranche of the Bonds presented to the Bond Trustee for cancellation on or before forty-five (45) days prior to a Payment Date shall reduce the amount to be redeemed on such Payment Date by a like principal amount.

If this Bond has a Final Maturity Date on or after December 15, 203_, it shall be subject to optional redemption by the Bond Issuer in whole or in part, in any order, from time to time on any Business Day on and after December 15, 20__, upon payment of the Redemption Price of 100% of the principal amount of the Bonds to be redeemed, together with accrued interest to the redemption date.

Notice of redemption of Bonds shall be given as provided by Section 10.06 of the Bond Indenture not less than 30 days before the redemption date to the Registered Holders of the Bonds to be redeemed, at their last addresses, if any, appearing on the Bond Register; provided, however, that if this Bond is a Book-Entry Bond, such notice shall be given to the Clearing Agency. Failure of the Registered Holder of any Bond which is to be redeemed to receive any notice of redemption shall not affect the sufficiency or validity of the proceedings for the redemption thereof.

Any notice of optional redemption of Bonds may state that it is conditional in whole or in part upon receipt by the Bond Trustee of moneys sufficient to pay the Redemption Price together with accrued interest to the redemption date, or upon the satisfaction of any other condition, or that it may be rescinded upon the occurrence of any other event, and any conditional notice so given may be rescinded if and to the extent any such other event occurs. Notice of such rescission, failure to fund the Redemption Price or satisfaction of such other condition shall be given by the Bond Trustee to affected Registered Holders of such Bonds as promptly as practicable upon the failure of such condition or the occurrence of such other event, in the same manner as the conditional notice of redemption was given.

As provided in the Bond Indenture and subject to certain limitations set forth therein, the transfer of this Bond may be registered on the Bond Register upon surrender of this Bond for registration of transfer at the office or agency designated by the Bond Issuer pursuant to the Bond Indenture, duly endorsed by, or accompanied by (a) a written instrument of transfer in form satisfactory to the Bond Trustee duly executed by the Holder hereof or his attorney duly authorized in writing, with such signature guaranteed by an institution which is a member of one of the following recognized Signature Guaranty Programs: (i) The Securities Transfer Agent Medallion Program (STAMP); (ii) The New York Stock Exchange Medallion Program (MSP); (iii) The Stock Exchange Medallion Program (SEMP); or (iv) in such other guarantee program acceptable to the Bond Trustee, and (b) such other documents as the Bond Trustee may require, and thereupon one or more new Bonds of this Tranche of Minimum Denominations and in the same aggregate principal amount will be issued to the designated transferee or transferees. No service charge will be charged for any registration of transfer or exchange of this Bond, but the transferor may be required to pay a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any such registration of transfer or exchange.

Prior to the due presentment for registration of transfer of this Bond, the Bond Issuer, the Bond Trustee and any agent of the Bond Issuer or the Bond Trustee may treat the Person in whose name this Bond is registered (as of the day of determination) as the owner hereof for the purpose of receiving payments of principal of and interest on this Bond and for all other purposes whatsoever, whether or not this Bond be overdue, and neither the Bond Issuer, the Bond Trustee nor any such agent shall be affected by notice to the contrary.

The Bond Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Bond Issuer and the rights of the Holders of the Bonds under the Bond Indenture at any time by the Bond Issuer with the consent of the Holders of Bonds representing a majority of the Outstanding Amount of all Bonds at the time Outstanding of each Tranche to be affected. The Bond Indenture also contains provisions permitting the Holders of Bonds representing specified percentages of the Outstanding Amount of the Bonds, on behalf of the Holders of all the Bonds, to waive compliance by the Bond Issuer with certain provisions of the Bond Indenture and certain past defaults under the Bond Indenture and their consequences. Any such consent or waiver by the Holder of this Bond (or any one of more Predecessor Bonds) shall be conclusive and binding upon such Holder and upon all future Holders of this Bond and of any Bond issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof whether or not notation of such consent or waiver is made upon this Bond. The Bond Indenture also permits the Bond Trustee to amend or waive certain terms and conditions set forth in the Bond Indenture without the consent of Holders of the Bonds issued thereunder.

The Bond Indenture contains provisions for defeasance at any time of the indebtedness of the Bond Issuer on this Bond upon compliance by the Bond Issuer with certain conditions set forth in the Bond Indenture.

The term "Bond Issuer" as used in this Bond includes any successor to the Bond Issuer under the Bond Indenture.

The Bonds are issuable only in registered form in Minimum Denominations as provided in the Bond Indenture, subject to certain limitations therein set forth.

This Bond and the Bond Indenture shall be construed in accordance with the laws of the State of New York, without reference to its conflict of law provisions, and the obligations, rights and remedies of the parties hereunder and thereunder shall be determined in accordance with such laws.

No reference herein to the Bond Indenture and no provision of this Bond or of the Bond Indenture shall alter or impair the obligation of the Bond Issuer, which is absolute and unconditional, to pay the principal of and interest on this Bond at the times, place, and rate, and in the coin or currency herein prescribed.

The Holder of this Bond by acceptance hereof agrees to be bound by the terms of the Bond Indenture. Further, the Holder of this Bond by acceptance hereof agrees that, notwithstanding any provision of the Bond Indenture to the contrary, the Holder shall have no recourse against the Bond Issuer, but shall look only to the Collateral, with respect to any amounts due to the Holder under this Bond.

Subject to and in accordance with the terms of the Bond Indenture and pursuant to Section 9(a) of the LIPA Reform Act, the State of New York has pledged and agreed with the Bond Issuer and the Holders of the Bonds (the "State Pledge"), as follows:

> "The state pledges to and agrees with the holders of restructuring bonds, any assignee, and all financing entities that the state will not in any way take or permit any action that limits, alters or impairs the value of restructuring property or, except as required by the adjustment mechanism described in the restructuring cost financing order, reduce, alter or impair transition charges that are imposed, collected and remitted for the benefit of the owners of restructuring bonds, any assignee, and all financing entities, until any principal, interest and redemption premium in respect of restructuring bonds, all ongoing financing costs and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid or performed in full."

It is hereby certified, recited and declared that all acts, conditions and things required to have happened, to exist and to have been performed precedent to and in the issuance of this Bond and the series of which it is one have happened, do exist and have been performed in regular and due time, form and manner as required by law; that this Bond and the series of which it is one do not exceed any constitutional or statutory or charter limitation of indebtedness; and that provision has been made for the payment of the principal of and interest on this Bond and the series of which it is one as provided in the Bond Indenture.

Unless the certificate of authentication hereon has been executed by the Bond Trustee whose name appears in the Bond Trustee's Certificate of Authentication below by manual signature, this Bond shall not be entitled to any benefit under the Bond Indenture, or be valid or obligatory for any purpose.

[Signature Page Follows]

IN WITNESS WHEREOF, the Bond Issuer has caused this instrument to be signed, manually or in facsimile, by its Authorized Officer.

Date: September __, 2022

UTILITY DEBT SECURITIZATION AUTHORITY

By:___________________________
Authorized Officer

BOND TRUSTEE’S CERTIFICATE OF AUTHENTICATION

Dated: September __, 2022

This is one of the Bonds described in the within-mentioned Bond Indenture.

THE BANK OF NEW YORK MELLON,
as Bond Trustee

By:___________________________
Authorized Officer

ABBREVIATIONS

The following abbreviations, when used in the inscription of the face of this Restructuring Bond, shall be construed as though they were written out in full according to applicable laws or regulations.

| | |
|---|---|
| TEN COM | as tenants in common |
| TEN ENT | as tenants by the entireties |
| JT TEN | as joint tenants with right of survivorship and not as tenants in common |
| UNIF GIFT MIN ACT | ____________________ Custodian ______________________<br>(Custodian) (minor)<br>Under Uniform Gifts to Minor Act (________________________)<br>(State) |

Additional abbreviations may also be used though not in the above list.

ASSIGNMENT

Social Security or taxpayer I.D. or other identifying number of assignee:_____________________

FOR VALUE RECEIVED, the undersigned hereby sells, assigns and transfers unto ___________
_____________________________________________________________________________
_____________________________________________________________________________

(name and address of assignee)

the within Bond and all rights thereunder, and hereby irrevocably constitutes and appoints attorney, to transfer said Bond on the books kept for registration thereof, with full power of substitution in the premises.

Dated:_________________

________________________________
________________________________

Signature Guaranteed:

_____________________________________________________________________________
_____________________________________________________________________________

* NOTE: The signature to this assignment must correspond with the name of the registered owner as it appears on the face of the within Bond in every particular, without alteration, enlargement or any change whatsoever.

* NOTE: Signature(s) must be guaranteed by an institution which is a member of one of the following recognized Signature Guaranty Programs: (i) The Securities Transfer Agent Medallion Program (STAMP), (ii) The New York Stock Exchange Medallion Program (MSP), (iii) the Stock Exchange Medallion Program (SEMP) or (iv) such other guarantee program acceptable to the Indenture Trustee.

**Attachment 4**

# SALE AGREEMENT

# RESTRUCTURING PROPERTY PURCHASE AND SALE AGREEMENT

between

UTILITY DEBT SECURITIZATION AUTHORITY,

as Bond Issuer

and

LONG ISLAND POWER AUTHORITY

as Seller

Dated as of September 29, 2022

TABLE OF CONTENTS

Page

This RESTRUCTURING PROPERTY PURCHASE AND SALE AGREEMENT, dated as of September 29, 2022 is between Utility Debt Securitization Authority, a special purpose corporate municipal instrumentality, body corporate and politic, political subdivision and public benefit corporation of the State of New York (the "Bond Issuer"), and the Long Island Power Authority, a corporate municipal instrumentality, body corporate and politic and a political subdivision of the State of New York (together with its successors in interest to the extent permitted hereunder, the "Seller").

RECITALS

WHEREAS, the Bond Issuer desires to purchase the Restructuring Property (as defined herein) created pursuant to the Statute and the Financing Order (each as defined herein); and

WHEREAS, the Seller is willing to sell the Restructuring Property to the Bond Issuer.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties hereto agree as follows:

## ARTICLE I. DEFINTIONS

Section 1.01. Definitions. Whenever used in this Agreement, the following words and phrases shall have the following meanings:

"Adjustment Notice" has the meaning specified in Appendix A of the Servicing Agreement.

"Administration Agreement" means the Administration Agreement, dated as of September 29, 2022, between Long Island Lighting Company, d/b/a LIPA, as Administrator, and the Bond Issuer, as amended and supplemented from time to time.

"Agreement" means this Restructuring Property Purchase and Sale Agreement, as amended and supplemented from time to time.

"Authority" means the Long Island Power Authority and any successor thereto.

"Authorized Officer" means the chief executive officer, the president, any vice president, the treasurer or any assistant treasurer of the Seller.

"Authority Regulations" has the meaning specified in Appendix A of the Servicing Agreement.

"Back-Up Security Interest" has the meaning specified in Section 2.01.

"Basic Documents" means, collectively, this Agreement, the Bond Indenture, the Servicing Agreement, the Administration Agreement, the Continuing Disclosure Agreement and the Bond Purchase Agreement.

"Bonds" means the Bonds issued under the Bond Indenture.

"Bondholder" or "Holder" means the Person in whose name a Bond is registered on the Bond Register.

"Bond Indenture" means the Bond Indenture, dated as of September 29, 2022, between the Bond Issuer and the Bond Trustee, as amended and supplemented from time to time.

"Bond Issuer" has the meaning set forth in the preamble of this Agreement.

"Bond Purchase Agreement" means the Bond Purchase Agreement, dated as of September 16, 2022, as amended on September 20, 2022, among the Bond Issuer and the underwriters named therein.

"Bond Register" has the meaning specified in Section 2.05 of the Bond Indenture.

"Bond Trustee" means the Person acting as trustee under the Bond Indenture.

"Business Day" means any day other than a Saturday, a Sunday or a day on which banking institutions or trust companies in New York, New York are authorized or obligated by law, regulation or executive order to remain closed.

"Charge" has the meaning specified in the Financing Order, as the same may be adjusted from time to time as provided in the Financing Order.

"Charge Collections" has the meaning specified in Appendix A of the Servicing Agreement.

"Closing Date" means the date of the issuance of the Bonds.

"Collateral" has the meaning specified in the Granting Clause of the Bond Indenture.

"Collection Account" has the meaning specified in Section 8.02(a) of the Bond Indenture.

"Continuing Disclosure Agreement" means the Continuing Disclosure Agreement, dated as of September 29, 2022, between the Issuer and the Servicer.

"Corporate Trust Office" has the meaning specified in Section 1.01 of the Bond Indenture.

"Customers" means consumers as defined in the Statute.

"Financing Cost" has the meaning specified in Section 1.01 of the Bond Indenture.

"Financing Order" means the Restructuring Cost Financing Order No. 6 of the Authority adopted on May 18, 2022.

"Fitch" means Fitch Ratings or its successor.

"Grant" means mortgage, pledge, collaterally assign and grant a Lien upon and a security interest in. A Grant of any agreement or instrument shall include all rights, powers and options (but none of the obligations) of the Granting Person thereunder, the immediate and continuing right to claim for, collect, receive and give receipts for payments in respect of and all other monies payable thereunder, to give and receive notices and other communications, to make waivers or other agreements, to exercise all rights and options, to bring proceedings in the name of the Granting Person or otherwise, and generally to do and receive anything that the Granting Person is or may be entitled to do or receive thereunder with respect thereto.

"Indemnified Person" has the meaning specified in Section 5.01(g).

"Issuance Advice Letter" means the initial Issuance Advice Letter, dated September 21, 2022, filed with the Authority and the Bond Issuer by the Servicer pursuant to Section 3.5 of the Statute.

"Lien" means a security interest, lien, mortgage, charge, pledge, claim or encumbrance of any kind.

"Losses" has the meaning specified in Section 5.01(d).

"Moody's" means Moody's Investors Service, Inc. or its successor.

"Officer's Certificate" means a certificate signed by any Authorized Officer of the Seller.

"Ongoing Financing Costs" has the meaning specified in the Financing Order.

"Operating Expenses" has the meaning specified in Section 1.01 of the Bond Indenture.

"Opinion of Counsel" means one or more written opinions of counsel who may be an employee of or counsel to the party providing such opinion of counsel, which counsel shall be reasonably acceptable to the party receiving such opinion of counsel.

"Outstanding Amount" has the meaning specified in Section 1.01 of the Bond Indenture.

"Person" means any individual, corporation, limited liability company, estate, partnership, joint venture, association, joint stock company, trust (including any beneficiary thereof), unincorporated organization or government or any agency or political subdivision thereof.

"Rating Agencies" means, collectively, S&P, Moody's and Fitch.

"Required Reserve Level" has the meaning specified in Section 1.01 of the Bond Indenture.

"Reserve Subaccount" has the meaning specified in Section 1.01 of the Bond Indenture.

"Restructuring Costs" has the meaning specified in the final Financing Order.

"Restructuring Property" means the restructuring property that is created simultaneous with the sale of such property by the Seller to the Bond Issuer and continues to exist pursuant to and in accordance with the Financing Order and Section 7 of the Statute.

"Seller" has the meaning set forth in the preamble of this Agreement.

"Servicer Default" means an event specified in Section 6.01 of the Servicing Agreement.

"Servicing Agreement" means the Restructuring Property Servicing Agreement, dated as of September 29, 2022, between the Long Island Lighting Company, as Servicer, and the Bond Issuer, as amended and supplemented from time to time.

"S&P" means Standard & Poor's Ratings Services, a division of McGraw Hill Financial, Inc., or its successor.

"Statute" means Part B of Chapter 173 of the State of New York Laws of 2013, as amended to the date hereof.

"UCC" means, unless the context otherwise requires, the Uniform Commercial Code, as in effect in the relevant jurisdiction, as amended from time to time.

"Upfront Financing Costs" has the meaning specified in the Financing Order.

Section 1.02. Rules of Construction. Unless the context otherwise requires:

(a) a term has the meaning assigned to it;

(b) all terms defined in this Agreement shall have the defined meanings when used in any certificate or other document made or delivered pursuant hereto unless otherwise defined therein.

(c) an accounting term not otherwise defined has the meaning assigned to it in accordance with generally accepted accounting principles as in effect from time to time;

(d) "or" is not exclusive; "including" means including without limitation;

(e) words in the singular include the plural and words in the plural include the singular;

(f) words of the masculine gender shall mean and include correlative words of the feminine and neuter genders;

(g) words importing persons shall include firms, associations, partnerships (including limited partnerships), trusts, corporations and other legal entities, including public bodies, as well as natural persons, and shall include successors and assigns;

(h) each time of day shall be local time in The City of New York, New York, except as otherwise specified herein;

(i) each reference to Bonds includes portions thereof in authorized denominations;

(j) the words "herein," "hereof," "hereunder" and other words of similar import refer to this Bond Indenture as a whole and not to any particular Article, Section or other subdivision;

(k) all references in this Agreement to designated "Articles," "Sections" and other subdivisions are to the designated Articles, Sections and other subdivisions of this Agreement; and

(l) except as otherwise specified herein, UCC terms shall have the meanings given to such terms in the UCC.

ARTICLE II. CONVEYANCE OF RESTRUCTURING PROPERTY

Section 2.01. Conveyance of Restructuring Property. In consideration of the Bond Issuer's delivery to or upon the order of the Seller of an amount equal to the net proceeds of the sale of the Bonds as set forth in Section B of the Issuance Advice Letter (such amount representing the proceeds of the Bonds net of the Upfront Financing Costs as set forth in Section B of the Issuance Advice Letter), the Seller does hereby irrevocably sell, transfer, assign, set over and otherwise convey to the Bond Issuer, WITHOUT RECOURSE OR WARRANTY, except as specifically set forth herein, all right, title and interest of the Seller in and to the Restructuring Property (such sale, transfer, assignment, setting over and conveyance of the Restructuring Property includes, to the fullest extent permitted by the Statute, the assignment of all revenues, collections, claims, payments, money or proceeds of or arising from the Charge pursuant to the Financing Order) and copies of all books and records related thereto. Such sale, transfer, assignment, setting over and conveyance is hereby expressly stated to be a sale and, pursuant to Section 7.3 of the Statute and the Financing Order, shall be treated as an absolute transfer of all of the Seller's right, title and interest in (as in a true sale), and not as a pledge or other financing of, the Restructuring Property, other than for accounting and federal, state and local income and franchise tax purposes. If such sale, transfer, assignment, setting over and conveyance is held by any court of competent jurisdiction not to be a true sale as provided in Section 7.3 of the Statute and the Financing Order, then such sale, transfer, assignment, setting over and conveyance shall be treated as the creation of a security interest in the Restructuring Property and, without prejudice to its position that it has absolutely transferred all of its right, title and interest in and to the Restructuring Property to the Bond Issuer, the Seller hereby Grants to the Bond Issuer a security interest in the Restructuring Property (including, to the fullest extent permitted by the Statute, the assignment of all revenues, collections, claims, payments, money or proceeds of or arising from the Charge pursuant to the Financing Order) to secure a payment obligation incurred by the Seller in respect of the amount paid by the Bond Issuer to the Seller pursuant to this Agreement (the "Back-Up Security Interest"). A UCC-1 financing statement will be filed in order to perfect the Back-Up Security Interest.

ARTICLE III. REPRESENTATIONS AND WARRANTIES OF SELLER

Subject to Section 3.09 hereof, the Seller makes the following representations and warranties, as of the Closing Date, on which the Bond Issuer has relied in acquiring the Restructuring Property.

Section 3.01. Organization and Good Standing. The Seller is duly organized and validly existing as a corporate municipal instrumentality, body corporate and politic and a political subdivision of the State of New York, in good standing under the laws of the State of New York, with the requisite power and authority to own its properties as such properties are currently owned and to conduct its business as such business is now conducted by it, and has the requisite power and authority to own the Restructuring Property.

Section 3.02. Due Qualification. The Seller is duly qualified to do business, and has obtained all necessary licenses and approvals, in all jurisdictions in which the ownership or lease of property or the conduct of its business shall require such qualifications, licenses or approvals (except where the failure to so qualify or obtain such licenses and approvals would not be reasonably likely to have a material adverse effect on the Seller's business, operations, assets, revenues or properties).

Section 3.03. Power and Authority. The Seller has the requisite power and authority to execute and deliver this Agreement and to carry out its terms; and the execution, delivery and performance of this Agreement have been duly authorized by all necessary action on the part of the Seller.

Section 3.04. Binding Obligation. This Agreement constitutes a legal, valid and binding obligation of the Seller enforceable against it in accordance with its terms, subject to applicable insolvency, reorganization, moratorium, fraudulent transfer and other laws relating to or affecting creditors' or secured parties' rights generally from time to time in effect and to general principles of equity (including concepts of materiality, reasonableness, good faith and fair dealing), regardless of whether considered in a proceeding in equity or at law.

Section 3.05. No Violation. The sale of the Restructuring Property and the consummation of the transactions contemplated by the Statute and this Agreement and the fulfillment of the terms hereof and thereof do not: (i) conflict with or result in any breach of any of the terms and provisions of, nor constitute (with or without notice or lapse of time) a default under, the organizational documents of the Seller or any material indenture, agreement or other instrument to which the Seller is a party or by which it is bound; (ii) result in the creation or imposition of any Lien upon any of the Seller's properties pursuant to the terms of any such indenture, agreement or other instrument (other than any Lien that may be Granted under the Basic Documents); or (iii) violate any existing law or any existing order, rule or regulation applicable to the Seller of any federal or state court or regulatory body, administrative agency or other governmental instrumentality having jurisdiction over the Seller or its properties.

Section 3.06. No Proceedings. There are no proceedings or investigations pending and, to the Seller's knowledge, there are no proceedings or investigations threatened, before any federal or state court, regulatory body, administrative agency or other governmental instrumentality having jurisdiction over the Seller or its properties involving or relating to the Seller or the Bond Issuer or, to the Seller's knowledge, any other Person: (i) asserting the invalidity of this Agreement, the Statute or the Financing Order, (ii) seeking to prevent the consummation of the transactions contemplated by this Agreement or the other Basic Documents, (iii) seeking any determination or ruling that might materially and adversely affect the performance by the Seller of its obligations under, or the validity or enforceability of, this Agreement, any of the other Basic Documents or the Bonds, or the validity of the Statute or the Financing Order or (iv) seeking to adversely affect the federal or state income tax classification of the Bonds as debt.

Section 3.07. Approvals. No approval, authorization, consent, order or other action of, or filing with, any federal or state court, regulatory body, administrative agency or other governmental instrumentality is required in connection with the execution and delivery by the Seller of this Agreement, the performance by the Seller of the transactions contemplated hereby or the fulfillment by the Seller of the terms hereof, except for those that have been obtained, waived or made and are in full force and effect.

Section 3.08. The Restructuring Property.

(a) Title. It is the intention of the parties hereto that the transfer and assignment herein contemplated constitute a sale of the Restructuring Property from the Seller to the Bond Issuer and that no interest in, or title to, the Restructuring Property shall be part of the Seller's estate in the event of the filing of a bankruptcy petition by or against the Seller under any bankruptcy law. No portion of the Restructuring Property has been sold, transferred, assigned or pledged by the Seller to any Person other than the Bond Issuer. On the Closing Date, immediately upon the sale hereunder, the Seller has transferred, sold and conveyed the Restructuring Property to the Bond Issuer, free and clear of all Liens, except for any Lien that may be Granted under the Basic Documents, and pursuant to Section 7.3 of the Statute and the Financing Order, such transfer shall be treated as an absolute transfer of all of the Seller's right, title and interest (as in a true sale), and not as a pledge or other financing of, the Restructuring Property.

(b) Transfer Filings. On the Closing Date, immediately upon the sale hereunder, the Restructuring Property has been validly transferred and sold to the Bond Issuer, the Bond Issuer shall own all such Restructuring Property free and clear of all Liens (except for any Lien that may be Granted under the Basic Documents) and all filings to be made by the Seller (including filings with the Authority under the Statute and the Financing Order) necessary in any jurisdiction to give the Bond Issuer a valid, perfected ownership interest (subject to any Lien that may be Granted under the Basic Documents) in, and for the Grant by the Bond Issuer to the Bond Trustee of a valid, first priority perfected security interest (except for any Lien that may be Granted under the Basic Documents) in, the Restructuring Property have been made. No further action is required to maintain such ownership interest or the Bond Trustee's perfected security interest (in each case, subject to any Lien that may be Granted under the Basic Documents). Filings have also been made to the extent required in any jurisdiction to perfect the Back-Up Security Interest Granted by the Seller to the Bond Issuer (subject to any Lien that may be Granted under the Basic Documents).

(c) Financing Order and Issuance Advice Letter; Other Approvals. On the Closing Date, under the laws of the State of New York and the United States in effect on the Closing Date, (i) the Financing Order pursuant to which the Restructuring Property has been created is in full force and effect; (ii) the Bondholders are entitled to the protections of the Statute, and the Financing Order is not revocable by the Authority; (iii) the State of New York may not take or permit any action that impairs the value of the Restructuring Property or, except as required by the adjustment mechanism described in the Financing Order, reduce, alter or impair Charges that are imposed, charged, collected or remitted for the benefit of the Bondholders in a manner that would substantially impair the rights of the Bondholders, absent a demonstration by the State of New York that an impairment is a reasonable exercise of its sovereign power and of a character reasonable and appropriate to the public purpose justifying such action, until the Bonds, together with interest thereon, and all other Ongoing Financing Costs are paid and performed in full; (iv) the process by which the Financing Order was adopted and approved, and the Financing Order and Issuance Advice Letter themselves, comply with all applicable laws, rules and regulations; (v) the Issuance Advice Letter has been filed in accordance with the Financing Order; and (vi) no other approval, authorization, consent, order, registration or other action of, or filing with, any court, Federal or state regulatory body, administrative agency or other governmental instrumentality is required in connection with the creation or sale of the Restructuring Property, except those that have been obtained, waived or made and are in full force and effect.

(d) Assumptions. On the Closing Date, based upon the information available to the Seller on the Closing Date, the assumptions used in calculating the initial Charge are reasonable and are made in good faith. Notwithstanding the foregoing, the Seller makes no representation or warranty that the assumptions used in calculating such Charge will in fact be realized.

(e) Creation of Restructuring Property. Upon the sale by the Seller to the Bond Issuer of all of the Seller's right, title and interest in the Restructuring Property (i) there will arise and constitute an existing present property right and interest of the Bond Issuer in such Restructuring Property which shall continue to exist until such time as the Bonds, together with interest thereon, and all other approved Financing Costs are paid in full; (ii) the creation of the Seller's Restructuring Property is confirmed and is simultaneous with the sale by the Seller to the Bond Issuer of such Restructuring Property; (iii) the Restructuring Property includes the right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Charge, as adjusted from time to time pursuant to the Financing Order, and all rights to obtain adjustments to the Charge pursuant to the Financing Order; and (iv) the owner of the Restructuring Property is legally entitled to collect payments in respect of the Charge in the aggregate sufficient to pay the interest on and principal of the Bonds, to pay the fees and expenses incurred by or allocable to the Bond Issuer in connection with servicing the Bonds, and to replenish the Reserve Subaccount to the Required Reserve Level until the Bonds, together with interest thereon, and all other approved Financing Costs are paid in full. Notwithstanding the foregoing, the Seller makes no representation or warranty that any amounts actually collected in respect of the Charge will in fact be sufficient to meet payment obligations with respect to the Bonds.

(f) Official Statement. The information under the heading "The Seller" in the Preliminary Official Statement relating to the Bonds, dated August 25, 2022, as supplemented on September 9, 2022, as of its date and at all times subsequent thereto up to the Applicable Time (as defined in the Bond Purchase Agreement), does not, and in the Official Statement relating to the Bonds, dated September 16, 2022 as of its date and at all times subsequent thereto up to the Closing Date, will not, contain an untrue statement of a material fact and will not omit to state a material fact necessary to make the statements therein, in light of the circumstances under which they were made, not misleading.

Section 3.09. Limitations on Representations and Warranties. Without prejudice to any of the other rights of the parties, the Seller will not be in breach of any representation or warranty as a result of a change in law by means of a legislative enactment, constitutional amendment or voter initiative or referendum. Notwithstanding anything to the contrary in this Agreement, the

Seller makes no representation or warranty that any amounts actually collected in respect of the Charge will in fact be sufficient to meet payment obligations with respect to the Bonds or that the assumptions used in calculating the Charge will in fact be realized nor shall the Seller be obligated to reduce, or accept a reduction of, any rates or charges to which it would otherwise be entitled in respect of services rendered or to be rendered to Customers in order to permit the payment of the Charge.

## ARTICLE IV. COVENANTS OF THE SELLER

Section 4.01. Existence. So long as any of the Bonds are outstanding, except as provided under Section 5.02, the Seller (a) will keep in full force and effect its existence, rights and franchises as a corporate municipal instrumentality, body corporate and politic and a political subdivision of the State of New York, and (b) will obtain and preserve its qualification to do business, in each case to the extent that in each such jurisdiction such existence or qualification is or shall be necessary to protect the validity and enforceability of this Agreement, the other Basic Documents to which the Seller is a party and each other instrument or agreement to which the Seller is a party necessary or appropriate to the proper administration of this Agreement and the transactions contemplated hereby.

Section 4.02. No Liens. Except for the conveyances hereunder or the Back-Up Security Interest, the Seller will not sell, pledge, assign or transfer, or Grant, create, or incur any Lien on, any of the Restructuring Property, or any interest therein, and the Seller shall defend the right, title and interest of the Bond Issuer and the Bond Trustee in, to and under the Restructuring Property against all claims of third parties claiming through or under the Seller. The Long Island Power Authority, in its capacity as Seller, will not at any time assert any Lien against, or with respect to, any of the Restructuring Property.

Section 4.03. Delivery of Collections. If the Seller receives any payments in respect of the Charge or the proceeds thereof when it is not acting as the Servicer, the Seller agrees to pay to the Servicer all payments received by it in respect thereof as soon as practicable after receipt thereof by it.

Section 4.04. Notice of Liens. The Seller shall notify the Bond Issuer and the Bond Trustee promptly after becoming aware of any Lien Granted on any of the Restructuring Property, other than the conveyances hereunder, any Lien under the Basic Documents or for the benefit of the Bond Issuer.

Section 4.05. Compliance with Law. The Seller hereby agrees to comply with its organizational and governing documents and all laws, treaties, rules, regulations and determinations of any governmental instrumentality applicable to it, except to the extent that failure to so comply would not adversely affect the Bond Issuer’s or the Bond Trustee’s interests in the Restructuring Property or under any of the other Basic Documents to which the Seller is party or the Seller’s performance of its obligations hereunder or under any of the other Basic Documents to which it is party.

Section 4.06. Covenants Related to Bonds and Restructuring Property.

(a) So long as any of the Bonds are outstanding, the Seller shall treat the Bonds as debt of the Bond Issuer and not of the Seller, except for financial, accounting or tax reporting purposes.

(b) So long as any of the Bonds are outstanding, the Seller shall indicate in its financial statements that it is not the owner of the Restructuring Property and shall disclose the effects of all transactions between the Seller and the Bond Issuer in accordance with generally accepted accounting principles.

(c) So long as any of the Bonds are outstanding, the Seller shall not own or purchase any Bonds.

(d) The Seller agrees that, upon the transfer and sale by the Seller of the Restructuring Property to the Bond Issuer pursuant to this Agreement, (i) to the fullest extent permitted by law, including the applicable Authority Regulations, the Bond Issuer shall have all of the rights originally held by the Seller with respect to the Restructuring Property, including the right (subject to the terms of the Servicing Agreement) to exercise any and all rights and remedies to collect any amounts payable by any Customer in respect of the Restructuring Property, notwithstanding any objection or direction to the contrary by the Seller and (ii) any payment by any Customer to the Bond Issuer shall discharge such Customer's obligations in respect of the Restructuring Property to the extent of such payment, notwithstanding any objection or direction to the contrary by the Seller.

(e) So long as any of the Bonds are outstanding, (i) the Seller shall not make any statement or reference in respect of the Restructuring Property that is inconsistent with the ownership thereof by the Bond Issuer (other than for financial accounting or tax reporting purposes), and (ii) the Seller shall not take any action in respect of the Restructuring Property except as otherwise contemplated by the Basic Documents.

Section 4.07. Protection of Title. The Seller shall execute and file such filings, including filings with the Authority pursuant to the Statute and UCC filings, and cause to be executed and filed such filings, all in such manner and in such places as may be required by law fully to preserve, maintain and protect the ownership interest of the Bond Issuer, and the security interest of the Bond Trustee, in the Restructuring Property and the Back-Up Security Interest, including all filings required under the Statute and the applicable UCC relating to the transfer of the ownership interest in the Restructuring Property by the Seller to the Bond Issuer, the Granting of a security interest in the Restructuring Property by the Bond Issuer to the Bond Trustee, and the Back-Up Security Interest, and the continued perfection of such ownership interest, security interest and the Back-Up Security Interest. The Seller shall deliver (or cause to be delivered) to the Bond Trustee (with copies to the Bond Issuer) file-stamped copies of, or filing receipts for, any document filed as provided above, as soon as available following such filing. The Seller shall institute any action or proceeding necessary to compel performance by the Authority or the State of New York of any of their obligations or duties under the Statute or the Financing Order, and the Seller agrees to take such legal or administrative actions, including defending against or instituting and pursuing legal actions and appearing or testifying at hearings or similar proceedings, as may be reasonably necessary (i) to protect the Bond Issuer, the Bond Trustee, the Bondholders, and any of their respective affiliates, officials, directors, employees, and agents from claims, state actions or other actions or proceedings of third parties which, if successfully pursued, would result in a breach of any representation set forth in Article III or (ii) to block or overturn any attempts to cause a repeal of, modification of or supplement to the Statute, the Financing Order, the Issuance Advice Letter, any other Adjustment Notice, or the rights of Bondholders by executive action, legislative enactment or constitutional amendment that would be adverse to the Bond Issuer, the Bond Trustee or the Bondholders. If the Servicer performs its obligations under Section 3.10 of the Servicing Agreement in all respects, such performance shall be deemed to constitute performance of the Seller's obligations pursuant to clause (ii) of the immediately preceding sentence. In such event, the Seller agrees to assist the Servicer as reasonably necessary to perform its obligations under Section 3.10 of the Servicing Agreement in all respects. The costs of any such actions or proceedings shall be payable from Charge Collections as an Operating Expense in accordance with the priorities set forth in Section 8.02(e) of the Bond Indenture. The Seller's obligations pursuant to this Section 4.07 shall survive and continue notwithstanding the fact that the payment of Operating Expenses pursuant to Section 8.02(e) of the Bond Indenture may be delayed (it being understood that the Seller may be required to advance its own funds to satisfy its obligations hereunder).

Section 4.08. Non-Petition Covenant. Notwithstanding any prior termination of this Agreement or the Bond Indenture, but subject to the right of a court of competent jurisdiction to order the sequestration and payment of revenues arising with respect to the Restructuring Property notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to any person or entity pursuant to Section 7.1(d) of the Statute, the Seller solely in its capacity as a creditor of the Bond Issuer shall not, prior to the date which is one year and one day after the termination of the Bond Indenture, petition or otherwise invoke or cause the Bond Issuer to invoke the process of any court or government authority for the purpose of commencing or sustaining an involuntary case against the Bond Issuer under any Federal or state bankruptcy, insolvency or similar law, appointing a receiver, liquidator, assignee, trustee, custodian, sequestrator or other similar official of the Bond Issuer or any substantial part of the property of the Bond Issuer, or, to the fullest extent permitted by law, ordering the winding up or liquidation of the affairs of the Bond Issuer.

Section 4.09. Taxes. So long as any of the Bonds are outstanding, the Seller shall, and shall cause each of its subsidiaries to, pay all material taxes, assessments and governmental charges imposed upon it or any of its properties or assets or with respect to any of its franchises, business, income or property before any penalty accrues thereon if the failure to pay any such taxes, assessments and governmental charges would, after any applicable grace periods, notices or other similar requirements, result in a Lien on the Restructuring Property; provided that no such tax need be paid if the Seller or one of its subsidiaries is contesting the same in good faith by appropriate proceedings promptly instituted and diligently conducted and if the Seller or such subsidiary has established appropriate reserves as shall be required in conformity with generally accepted accounting principles.

Section 4.10. Additional Sales of Restructuring Property. So long as any of the Bonds are outstanding, the Seller shall not sell any "restructuring property" (as defined in the Statute) to secure another issuance of restructuring bonds (as defined in the Statute) if it would cause the then existing ratings on the Bonds from the Rating Agencies to be downgraded, withdrawn or suspended.

Section 4.11. Tax Exempt Bonds. The Seller covenants that it shall comply with the tax certificates to be executed and delivered by it in connection with the issuance of the Bonds and with letters of instruction, if any, delivered by bond counsel in connection with the issuance of the Bonds, as such tax certificates and letters may be amended from time to time. Notwithstanding anything else in this Agreement to the contrary, the covenants of this Section 4.11 shall survive the payment, redemption or defeasance of the Bonds and the termination of this Agreement.

## ARTICLE V. THE SELLER

Section 5.01. Liability of Seller: Indemnities.

(a) The Seller shall be liable in accordance herewith only to the extent of the obligations specifically undertaken by the Seller under this Agreement.

(b) The Seller shall indemnify the Bond Issuer, the Bond Trustee and, the Bondholders for, and defend and hold harmless each such Person from and against, any and all taxes (other than taxes imposed on Bondholders solely as a result of their ownership of Bonds) that may at any time be imposed on or asserted against any such Person under existing law as of the Closing Date as a result of the sale of the Restructuring Property to the Bond Issuer, including any sales, gross receipts, general corporation, tangible personal property, privilege or license taxes; provided, however, that the Bondholders shall be entitled to enforce their rights against the Seller under this Section 5.01(b) solely through a cause of action brought for their benefit by the Bond Trustee.

(c) The Seller shall indemnify the Bond Issuer, the Bond Trustee, and the Bondholders for, and defend and hold harmless each such Person from and against, any and all taxes that may be imposed on or asserted against any such Person under existing law as of the Closing Date as a result of the issuance and sale by the Bond Issuer of the Bonds or the other transactions contemplated herein, including any sales, gross receipts, general corporation, tangible personal property, privilege or license taxes; provided, however, that the Bondholders shall be entitled to enforce their rights against the Seller under this Section 5.01(c) solely through a cause of action brought for their benefit by the Bond Trustee. The Seller shall be reimbursed for any payments under this Section 5.01(c) from Charge Collections as an Operating Expense in accordance with the priorities set forth in Section 8.02(e) of the Bond Indenture.

(d) The Seller shall indemnify the Bond Issuer, the trustees, officers, employees and agents of the Bond Issuer, and the Bondholders for, and defend and hold harmless each such Person from and against, any and all liabilities, obligations, losses, actions, suits, claims, damages, payments, costs or expenses of any kind whatsoever (collectively, “Losses”) that may be imposed on, incurred by or asserted against each such Person as a result of (i) the Seller’s willful misconduct or negligence in the performance of its duties or observance of its covenants under this Agreement, or (ii) the Seller’s breach in any material respect of any of its representations and warranties contained in this Agreement, except in the case of both clauses (i) and (ii) to the extent of Losses either resulting from the willful misconduct or negligence of such indemnified person or resulting from a breach of a representation and warranty made by such indemnified person in any of the Basic Documents that gives rise to the Seller's breach; provided, however, that the Bondholders shall be entitled to enforce their rights against the Seller under this indemnification solely through a cause of action brought for their benefit by the Bond Trustee;

(e) Indemnification under Sections 5.01(b), 5.01(c), 5.01(d) and 5.01(g) shall include reasonable fees and out-of-pocket expenses of investigation and litigation (including reasonable attorneys' fees and expenses), except as otherwise provided in this Agreement.

(f) Without prejudice to any of the other rights of the parties, the Seller will not be in breach of any representation or warranty as a result of a change in law by means of a legislative enactment or constitutional amendment. Notwithstanding anything to the contrary in this Agreement, the Seller makes no representation or warranty that any amounts actually collected in respect of the Charge will in fact be sufficient to meet payment obligations with respect to the Bonds and, hence, the Bond Issuer's allocable portion of the Certificates or that the assumptions used in calculating the Charge will in fact be realized nor shall the Seller be obligated to reduce, or accept a reduction of, any rates or charges to which it would otherwise be entitled in respect of services rendered or to be rendered to customers in order to permit the payment of the Charge.

(g) The Seller shall indemnify and hold harmless the Bond Trustee and any of its affiliates, officials, officers, directors, employees and agents (each an "Indemnified Person") against any and all Losses incurred by any of such Indemnified Persons as a result of (i) the Seller's willful misconduct or negligence in the performance of its duties or observance of its covenants under this Agreement or (ii) the Seller's breach in any material respect of any of its representations and warranties contained in this Agreement, except in the case of both clauses (i) and (ii) to the extent of Losses either resulting from the willful misconduct or negligence of such Indemnified Person or resulting from a breach of a representation or warranty made by such Indemnified Person in any of the Basic Documents that gives rise to the Seller's breach. The Seller shall not be required to indemnify an Indemnified Person for any amount paid or payable by such Indemnified Person in the settlement of any action, proceeding or investigation without the written consent of the Seller, which consent shall not be unreasonably withheld. The obligations of the Seller under this Section 5.01(g) shall survive the resignation or removal of the foregoing trustees and the termination of the Basic Documents. Promptly after receipt by an Indemnified Person of notice of its involvement in any action, proceeding or investigation, such Indemnified Person shall, if a claim for indemnification in respect thereof is to be made against the Seller under this Section 5.01(g), notify the Seller in writing of such involvement. Failure by an Indemnified Person to so notify the Seller shall relieve the Seller from the obligation to indemnify and hold harmless such Indemnified Person under this Section 5.01(g) only to the extent that the Seller suffers actual prejudice as a result of such failure. With respect to any action, proceeding or investigation brought by a third party for which indemnification may be sought under this Section 5.01(g), the Seller shall be entitled to assume the defense of any such action, proceeding or investigation. Upon assumption by the Seller of the defense of any such action, proceeding or investigation, the Indemnified Person shall have the right to participate in such action or proceeding and to retain its own counsel. The Seller shall be entitled to appoint counsel of the Seller's choice at the Seller's expense to represent the Indemnified Person in any action, proceeding or investigation for which a claim of indemnification is made against the Seller under this Section 5.01(g) (in which case the Seller shall not thereafter be responsible for the fees and expenses of any separate counsel retained by the Indemnified Person except as set forth below); provided, however, that such counsel shall be reasonably satisfactory to the Indemnified Person. Notwithstanding the Seller's election to appoint counsel to represent the Indemnified Person in an action, proceeding or investigation, the Indemnified Person shall have the right to employ separate counsel (including local counsel), and the Seller shall bear the reasonable fees, costs and expenses of such separate counsel if (i) the use of counsel chosen by the Seller to represent the Indemnified Person would present such counsel with a conflict of interest, (ii) the actual or potential defendants in, or targets of, any such action include both the Indemnified Person and the Seller and the Indemnified Person shall have reasonably concluded that there may be legal defenses available to it that are different from or additional to those available to the Seller, (iii) the Seller shall not have employed counsel reasonably satisfactory to the Indemnified Person to represent the Indemnified Person within a reasonable time after notice of the institution of such action or (iv) the Seller shall authorize the Indemnified Person to employ separate counsel at the expense of the Seller. Notwithstanding the foregoing, the Seller shall not be obligated to pay for the fees, costs and expenses of more than one separate counsel for the Indemnified Persons other than local counsel. The Seller will not, without the prior written consent of the Indemnified Person, settle or compromise or consent to the entry of any judgment with respect to any pending or threatened claim, action, suit or proceeding in respect of which indemnification may be sought under this Section 5.01(g) (whether or not the Indemnified Person is an actual or potential party to such claim or action) unless such settlement, compromise or consent includes an unconditional release of the Indemnified Person from all liability arising out of such claim, action, suit or proceeding.

(h) The remedies of the Bond Issuer and the Bondholders provided in this Agreement are each such Person's sole and exclusive remedies against the Seller for breach of its representations and warranties in this Agreement.

Section 5.02. Merger or Consolidation of, or Assumption of the Obligations of, Seller. Any Person (a) into which the Seller may be merged or consolidated, (b) that may result from any merger or consolidation to which the Seller shall be a party or (c) that may succeed to the properties and assets of the Seller substantially as a whole, which Person in any of the foregoing cases executes an agreement of assumption to perform every obligation of the Seller hereunder, shall be the successor to the Seller under this Agreement without further act on the part of any of the parties to this Agreement; provided, however, that (i) if the Seller is the Servicer, no Servicer Default, and no event which, after notice or lapse of time, or both, would become a Servicer Default shall have occurred and be continuing, (ii) the Seller shall have delivered to the Bond Issuer and the Bond Trustee an Officers' Certificate stating that such consolidation, merger or succession and such agreement of assumption comply with this Section and that all conditions precedent, if any, provided for in this Agreement relating to such transaction have been complied with, (iii) the Seller shall have delivered to the Bond Issuer and the Bond Trustee an Opinion of Counsel either (A) stating that, in the opinion of such counsel, such consolidation, merger or succession and such agreement of assumption comply with this Section and that all conditions precedent provided for in this Agreement relating to such transaction have been complied with and (B) either (1) all filings to be made by the Seller, including filings with the Authority pursuant to the Statute and under the applicable UCC, have been executed and filed that are necessary to fully preserve and protect the interests of the Bond Issuer and the Bond Trustee in the Restructuring Property and reciting the details of such filings, or (2) no such action shall be necessary to preserve and protect such interests and (iv) the Rating Agencies shall have received prior written notice of such transaction from the Seller. When any Person acquires the properties and assets of the Seller substantially as a whole and becomes the successor to the Seller in accordance with the terms of this Section 5.02, then upon satisfaction of all of the other conditions of this Section 5.02, the Seller shall automatically and without further notice be released from all of its obligations hereunder.

Section 5.03. Limitation on Liability of Seller and Others. The Seller and any director, officer, employee or agent of the Seller may rely in good faith on the advice of counsel or on any document of any kind, prima facie properly executed and submitted by any Person, respecting any matters arising hereunder.

## ARTICLE VI. MISCELLANEOUS PROVISIONS

Section 6.01. Amendment. This Agreement may be amended by the Seller and the Bond Issuer, with (a) ten Business Days' prior written notice given to the Rating Agencies, (b) the prior written consent of the Bond Trustee, and (c) if any amendment would adversely affect in any material respect the interests of any Bondholder, the prior written consent of a majority of the Outstanding Amount of the Bonds affected thereby.

It shall not be necessary for the consent of Bondholders pursuant to this Section to approve the particular form of any proposed amendment or consent, but it shall be sufficient if such consent shall approve the substance thereof.

Prior to the execution of any amendment to this Agreement, the Bond Trustee shall be entitled to receive and rely upon an Opinion of Counsel stating that the execution of such amendment is authorized or permitted by this Agreement and all conditions precedent have been satisfied. The Bond Trustee may, but shall not be obligated to, enter into any such amendment which affects the Bond Trustee's own rights, duties or immunities under this Agreement or otherwise.

The Bond Issuer shall provide a copy of any amendment to this Agreement to the Bond Trustee and the Rating Agencies promptly after the execution thereof.

Section 6.02. Notices. Unless otherwise specifically provided herein, all notices, directions, consents and waivers required under the terms and provisions of this Agreement shall be in English and in writing, and any such notice, direction, consent or waiver may be given by United States mail, courier service, facsimile transmission or electronic mail (confirmed by telephone, United States mail or courier service in the case of notice by facsimile transmission or electronic mail) or any other customary means of communication, and any such notice, direction, consent or waiver shall be effective when delivered, or if mailed, three days after deposit in the United States mail with proper postage for ordinary mail prepaid:

(a) if to the Seller, to:

Long Island Power Authority
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive Officer and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(b) if to the Bond Issuer, to:

Utility Debt Securitization Authority
c/o LIPA, as Administrator
333 Earle Ovington Boulevard
Uniondale, New York 11553
Attention: Chief Executive Officer and Interim Chief Financial Officer
Telephone: (516) 222-7700
Telecopy: (516) 222-9137
Email: tfalcone@lipower.org

(c) if to the Bond Trustee, to:

The Bank of New York Mellon
385 Rifle Camp Road – 3rd Floor
Woodland Park, NJ 07424
Attention: Frederic Belen
Telephone: (973) 247-4395
Telecopy: (732) 667-9205
Email: frederic.belen@bnymellon.com

(d) if to Moody's, to:

Moody's Investors Service, Inc.
[25th Floor, 7 World Trade Center, 250 Greenwich Street
New York, New York 10007
Attention: ABS/RMBS Monitoring Department
Email: ServicerReports@moodys.com
Facsimile: (212) 553-0573
Telephone: (212) 553-3686]

(e) if to S&P, to:

Standard & Poor's Rating Services
[55 Water Street
New York, NY 10041
Attention: Structured Credit Surveillance
Telephone: (212) 438-8991
E-mail: servicer-reports@standardandpoors.com]

(f) if to Fitch, to:

Fitch Ratings
[33 Whitehall Street
New York, New York 10004
Attention: ABS Surveillance
Email: surveillance-abs-other@fitchratings.com
Telephone: (212) 908-0500]

(g) as to each of the foregoing, at such other address as shall be designated by written notice to the other parties.

Section 6.03. Assignment. Notwithstanding anything to the contrary contained herein, except as provided in Section 5.02 and Section 6.09, this Agreement may not be assigned by the Seller.

Section 6.04. Limitations on Rights of Third Parties. The provisions of this Agreement are solely for the benefit of the Seller, the Bond Issuer, the Bondholders, the Bond Trustee and the other Persons expressly referred to herein, and such Persons shall have the right to enforce the relevant provisions of this Agreement, except that the Bondholders shall be entitled to enforce their rights against the Seller under this Agreement solely through a cause of action brought for their benefit by the Bond Trustee. Nothing in this Agreement, whether express or implied, shall be construed to give to any other Person any legal or equitable right, remedy or claim in the Restructuring Property or under or in respect of this Agreement or any covenants, conditions or provisions contained herein.

Section 6.05. Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

Section 6.06. Separate Counterparts. This Agreement may be executed by the parties hereto in separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute but one and the same instrument.

Section 6.07. Headings. The headings of the various Articles and Sections herein are for convenience of reference only and shall not define or limit any of the terms or provisions hereof.

Section 6.08. Governing Law. This Agreement shall be construed in accordance with the laws of the State of New York, without reference to its conflict of law provisions, and the obligations, rights and remedies of the parties hereunder shall be determined in accordance with such laws.

Section 6.09. Collateral Assignment to Bond Trustee. The Seller hereby acknowledges and consents to the Grant of a security interest and collateral assignment by the Bond Issuer to the Bond Trustee pursuant to the Bond Indenture for the benefit of the Bondholders and the Bond

Trustee of all right, title and interest of the Bond Issuer in, to and under the Restructuring Property and the proceeds thereof and all other Collateral (including, without limitation all of the Bond Issuer's rights hereunder).

Section 6.10. Rule 17g-5 Compliance. The Seller and Bond Issuer agree that any notice, report, document or other information provided by the Seller or Bond Issuer to any Rating Agency under this Agreement or any other Basic Document to which it is a party, for the purpose of determining the initial credit rating of the Bonds or undertaking credit rating surveillance of the Bonds with any Rating Agency, shall be provided, substantially concurrently, to the Servicer for posting on the 17g-5 Website.

[SIGNATURE PAGE FOLLOWS.]

IN WITNESS WHEREOF, the parties hereto have caused this Restructuring Property Purchase and Sale Agreement to be duly executed by their respective officers as of the day and year first above written.

UTILITY DEBT SECURITIZATION AUTHORITY,
as Bond Issuer

By: ____________________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

LONG ISLAND POWER AUTHORITY,
as Seller

By: ____________________________________
Name:
Title: Chief Executive Officer and Interim Chief Financial Officer

# ISSUANCE ADVICE LETTER

**AUGUST 23, 2022**

**THE OKLAHOMA CORPORATION COMMISSION**
**Attn: Chair**
**Jim Thorpe Office Building,**
**2101 N. Lincoln Boulevard**
**Oklahoma City, Oklahoma 73105**

**SUBJECT: ISSUANCE ADVICE LETTER FOR RATEPAYER-BACKED BONDS**

Pursuant to the Final Financing Order issued on the 25th day of January, 2022 in Cause No. PUD 202100079 before the Oklahoma Corporation Commission, *Application of Oklahoma Natural Gas Company, a Division of One Gas, Inc. for a Financing Order Approving Securitization of Costs Arising from the February 2021 Winter Weather Event Pursuant to the "February 2021 Regulated Utility Consumer Protection Act"* (the "Financing Order"), OKLAHOMA NATURAL GAS COMPANY (the "Utility" or the "Applicant") and THE OKLAHOMA DEVELOPMENT FINANCE AUTHORITY ("ODFA" or the "Authority") jointly submit, this Issuance Advice Letter to report certain terms and information related to the RATEPAYER-BACKED BONDS (OKLAHOMA NATURAL GAS COMPANY) SERIES 2022 (FEDERALLY TAXABLE), Tranches A-1, A-2 and A-3. Any capitalized terms not defined in this letter shall have the meanings ascribed to them in the Financing Order or the February 2021 Regulated Utility Consumer Protection Act, 74 Okla. Stat. §§ 9071-9081 (the "Act").

## PURPOSE

This filing includes the following information:

(1) Calculation of total principal amount of Bonds issued;

(2) The final terms and structure of the ratepayer-backed bonds, including a description of any credit enhancement, the final estimated bond issuance costs and the final estimates of ongoing financing costs for the first year following issuance;

(3) A calculation of projected customer savings relative to conventional methods of financing resulting from the issuance of the Bonds; and

(4) The initial WESCR Charges.

## 1. PRINCIPAL AMOUNT OF BONDS ISSUED (AUTHORIZED AMOUNT)

The total amount of qualified costs, carrying costs and issuance costs being financed (the "Authorized Amount") is presented in Attachment 1.

## 2. DESCRIPTION OF FINAL TERMS OF BONDS

Set forth below is a summary of the final terms of the Bond Issuance.

Ratepayer-Backed Bond Title and Series: RATEPAYER-BACKED BONDS (OKLAHOMA NATURAL GAS COMPANY) SERIES 2022 (FEDERALLY TAXABLE)
Trustee: BOKF, NA
Closing Date: August 25, 2022
Bond Ratings: Moody's Aaa(sf); Fitch AAAsf
Amount Issued (Authorized Amount): $1,354,200,000
Ratepayer-Backed Bond Issuance Costs: See Attachment 1, Schedule B.
Ratepayer-Backed Bond Ongoing Financing Costs: See Attachment 2, Schedule B.

| Tranche | Coupon Rate | Scheduled Final Maturity | Legal Final Maturity |
|---|---|---|---|
| A-1 | 3.877% | 5/1/2032 | 5/1/2037 |
| A-2 | 4.380% | 11/1/2040 | 11/1/2045 |
| A-3 | 4.714% | 5/1/2047 | 5/1/2052 |

| | |
|---|---|
| Effective Annual Weighted Average Interest Rate of the Ratepayer-Backed Bonds: | 4.523 % |
| Weighted Average Life of Series: | 14.66 years |
| Call provisions (including premium, if any): | None. |
| Expected Sinking Fund Schedule: | Attachment 2, Schedule A |
| Payments to Bondholders: | Semiannually Beginning May 1, 2023, and each May 1 and November 1 thereafter through the last Legal Final Maturity Date |

## 3. CALCULATION OF PROJECTED SAVINGS

The weighted average interest rate of the ratepayer-backed bonds (excluding costs of issuance and ongoing financing costs) is less than ONG's 8.88% cost of capital, accordingly, the proposed structuring, expected pricing, and financing costs of the ratepayer-backed bonds are reasonably expected to result in substantial revenue requirement savings as compared to conventional methods of financing. The net present value of the savings, which will avoid or mitigate rate impacts as compared to conventional methods of financing the qualified costs, is estimated to be $845 million (see Attachment 2, Schedule C), based on an effective annual weighted average interest rate of 4.523% for the ratepayer-backed bonds.

## 4. INITIAL WESCR CHARGE

Table I below shows the current assumptions for each of the variables used in the calculation of the initial WESCR Charges.

**TABLE I**

**Input Values For Initial WESCR Charges**

| Applicable Period: | From: 8/25/22<br>To: 5/1/23 | From: 5/1/23<br>To: 11/1/23 |
|---|---|---|
| Forecasted customer count for each WESCR Customer Class for the applicable period: * | | |
| Tariffs 101 & 101-V Rate Choice A | 204,907 | 200,693 |
| Tariffs101 & 101-V Rate Choice B | 605,397 | 607,159 |
| Tariffs 200 SCI & 200 SCI-V | 47,034 | 46,598 |
| Tariff 200 LCI | 27,423 | 27,398 |
| Tariff 291S | 83 | 87 |
| Tariff 601S | 2 | 2 |
| Tariff 705 | 10 | 10 |
| Ratepayer-back bond debt service for the applicable period: | $68,268,062 | $45,463,452 |
| Charge-off rate for each WESCR Customer Class: | | |
| Tariffs 101 & 101-V Rate Choice A | 0.32% | 0.32% |
| Tariffs101 & 101-V Rate Choice B | 0.32% | 0.32% |
| Tariffs 200 SCI & 200 SCI-V | 0.16% | 0.16% |
| Tariff 200 LCI | 0.16% | 0.16% |
| Tariff 291S | 0.00% | 0.00% |
| Tariff 601S | 0.00% | 0.00% |
| Tariff 705 | 0.00% | 0.00% |
| Estimated Charge off Amount: | $200,250 | $150,188 |
| Forecasted annual ongoing financing costs (See Attachment 2, Schedule B): | $788,250 | $591,188 |
| Current Ratepayer-Backed Bond outstanding balance: | $1,354,200,000 | $1,326,382,018 |
| Target Ratepayer-Backed Bond outstanding balance as of next bond payment: | $1,326,382,018 | $1,309,976,933 |
| Total Periodic Billing Requirement for applicable period: | $69,256,562 | $46,204,828 |

** Reflects adjustments due to factors including the collection curve and charge-off assumptions.*

Based on the foregoing, the initial WESCR Charges calculated for each WESCR Customer Class are detailed in Attachment 3

**EFFECTIVE DATE**

In accordance with the Financing Order, the WESCR Charges shall become effective beginning on the first day of the first billing cycle of the next revenue month following the date of issuance of the ratepayer-backed bonds.

**AUTHORIZED OFFICER**

The undersigned are officers of Applicant and Authority, respectively, and authorized to deliver this Issuance Advice Letter on behalf of Applicant and Authority.

Respectfully submitted,

THE OKLAHOMA DEVELOPMENT
FINANCE AUTHORITY

By: ______________________________
Name: Michael Davis
Title: President

OKLAHOMA NATURAL GAS COMPANY, a
Division of ONE Gas, Inc.

By: ______________________________
Name: ______________________________
Title: ______________________________

cc: Director of the Public Utility Division, Oklahoma Corporation Commission

**AUTHORIZED OFFICER**

The undersigned are officers of Applicant and Authority, respectively, and authorized to deliver this Issuance Advice Letter on behalf of Applicant and Authority.

Respectfully submitted,

THE OKLAHOMA DEVELOPMENT
FINANCE AUTHORITY

By: ______________________
Name: ______________________
Title: ______________________

OKLAHOMA NATURAL GAS COMPANY, a
Division of ONE Gas, Inc.

By: Caron A. Lawhorn
Name: Caron A. Lawhorn
Title: Senior Vice President and Chief Financial Officer

cc: Director of the Public Utility Division, Oklahoma Corporation Commission

ONE GAS
BLS
LEGAL APPROVED

*Signature Page to Issuance Advice Letter*

**ATTACHMENT 1**
**SCHEDULE A**
**CALCULATION OF AUTHORIZED AMOUNT**

| | | |
|---|---|---|
| A. | Qualified costs authorized in Cause No. PUD 202100079 (including any adjustment to carrying costs) | $1,337,849,589 |
| B. | Estimated bond issuance costs (Attachment 1, Schedule B) | $16,350,411 |
| **TOTAL AUTHORIZED AMOUNT** | | $1,354,200,000 |

# ATTACHMENT 1
# SCHEDULE B
# ISSUANCE COSTS

| | **Issuance Costs** |
|---|---|
| Underwriters' Fees and Expenses | $5,568,729.71 |
| Underwriters' Counsel Legal Fees and Expenses | $150,000.00 |
| ODFA Financing Acceptance Fee | $100,000.00 |
| Council of Bond Oversight Fee | $146,650.00 |
| Bond Counsel Fees | $214,723.00 |
| Rating Agency Fees and Related Expenses | $945,000.00 |
| Printing - Estimated | $5,000.00 |
| Trustee's/Trustee Counsel's Fees and Expenses | $20,000.00 |
| ODFA Legal Fees | $50,000.00 |
| ODFA and Oklahoma Corporation Commission Financial Advisor Fees | $410,000.00 |
| Counsel to ODFA and Oklahoma Corporation Commission Financial Advisor | $175,000.00 |
| Oklahoma Corporation Commission Counsel – Contracted through Financial Advisor | $50,000.00 |
| Special Counsel | $685,000.00 |
| Disclosure Counsel | $260,000.00 |
| State of Oklahoma Attorney General Fee | $146,650.00 |
| Bond Link | $23,325.00 |
| Rule 17g-5 Website | $4,000.00 |
| Internet Roadshow - Estimate | $7,500.00 |
| Miscellaneous Expenses | $50,000.00 |
| Rounding Amount/Contingency | $67,833.29 |
| | |
| **Total Non-Utility External Issuance Costs** | **$9,079,411.00** |
| | |
| | |
| Utility's Counsel Legal Fees and Expenses | $250,000.00 |
| Utility's Non-legal Securitization Proceeding Costs and Expenses | $250,000.00 |
| **Total ONG Issuance Costs** | **$500,000.00** |
| | |
| **Total Estimated Issuance Costs & Rounding Amount** | **$9,579,411.00** |
| | |
| **Debt Service Reserve Subaccount (DSRS)** | **$6,771,000.00** |
| | |
| **Total** | **$16,350,411.00** |

**Note: Any difference between the Estimated Issuance Costs financed for, and the actual Issuance Costs incurred by, the ODFA and (except as capped) the Utility will be resolved, if estimates are more or less than actual, through the WESCR Mechanism or pursuant to the Financing Order issued in this proceeding, as applicable.**

# ATTACHMENT 2
# SCHEDULE A
# RATEPAYER-BACKED BOND FUNDING REQUIREMENT INFORMATION
# EXPECTED SINKING FUND SCHEDULE

| SERIES 2022, TRANCHE A-1 | | | | |
|---|---|---|---|---|
| **Payment Date** | **Principal Balance** | **Interest** | **Principal** | **Total Payment** |
| 8/25/22 | $375,000,000.00 | | | |
| 5/1/23 | $347,182,017.71 | $9,934,812.50 | $27,817,982.29 | $37,752,794.79 |
| 11/1/23 | $330,776,933.22 | $6,730,123.41 | $16,405,084.49 | $23,135,207.90 |
| 5/1/24 | $314,052,810.85 | $6,412,110.85 | $16,724,122.37 | $23,136,233.22 |
| 11/1/24 | $297,003,446.11 | $6,087,913.74 | $17,049,364.74 | $23,137,278.48 |
| 5/1/25 | $279,622,513.85 | $5,757,411.80 | $17,380,932.26 | $23,138,344.06 |
| 11/1/25 | $261,903,565.91 | $5,420,482.43 | $17,718,947.94 | $23,139,430.37 |
| 5/1/26 | $243,840,028.73 | $5,077,000.63 | $18,063,537.18 | $23,140,537.81 |
| 11/1/26 | $225,425,200.90 | $4,726,838.96 | $18,414,827.83 | $23,141,666.79 |
| 5/1/27 | $206,652,250.72 | $4,369,867.52 | $18,772,950.18 | $23,142,817.70 |
| 11/1/27 | $187,514,213.59 | $4,005,953.88 | $19,138,037.13 | $23,143,991.01 |
| 5/1/28 | $168,003,989.48 | $3,634,963.03 | $19,510,224.11 | $23,145,187.14 |
| 11/1/28 | $148,114,340.28 | $3,256,757.34 | $19,889,649.20 | $23,146,406.54 |
| 5/1/29 | $127,837,887.14 | $2,871,196.49 | $20,276,453.14 | $23,147,649.63 |
| 11/1/29 | $107,167,107.67 | $2,478,137.44 | $20,670,779.47 | $23,148,916.91 |
| 5/1/30 | $86,094,333.21 | $2,077,434.38 | $21,072,774.46 | $23,150,208.84 |
| 11/1/30 | $64,611,745.98 | $1,668,938.65 | $21,482,587.23 | $23,151,525.88 |
| 5/1/31 | $42,711,376.13 | $1,252,498.70 | $21,900,369.85 | $23,152,868.55 |
| 11/1/31 | $20,385,098.84 | $827,960.03 | $22,326,277.29 | $23,154,237.32 |
| 5/1/32 | - | $395,165.14 | $20,385,098.84 | $20,780,263.98 |
| 11/1/32 | - | - | - | - |

| SERIES 2022, TRANCHE A-2 | | | | |
|---|---|---|---|---|
| **Payment Date** | **Principal Balance** | **Interest** | **Principal** | **Total Payment** |
| 8/25/22 | $450,000,000.00 | | | |
| 5/1/23 | $450,000,000.00 | $13,468,500.00 | - | $13,468,500.00 |
| 11/1/23 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/24 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/24 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/25 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/25 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/26 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/26 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/27 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/27 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/28 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/28 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/29 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/29 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/30 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/30 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/31 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 11/1/31 | $450,000,000.00 | $9,855,000.00 | - | $9,855,000.00 |
| 5/1/32 | $447,624,631.27 | $9,855,000.00 | $2,375,368.73 | $12,230,368.73 |
| 11/1/32 | $424,415,555.45 | $9,802,979.42 | $23,209,075.82 | $33,012,055.24 |
| 5/1/33 | $400,696,750.31 | $9,294,700.66 | $23,718,805.14 | $33,013,505.80 |

| | | | | |
|---|---|---|---|---|
| 11/1/33 | $376,457,020.91 | $8,775,258.83 | $24,239,729.40 | $33,014,988.23 |
| 5/1/34 | $351,684,926.45 | $8,244,408.76 | $24,772,094.46 | $33,016,503.22 |
| 11/1/34 | $326,368,774.87 | $7,701,899.89 | $25,316,151.58 | $33,018,051.47 |
| 5/1/35 | $300,496,617.31 | $7,147,476.17 | $25,872,157.56 | $33,019,633.73 |
| 11/1/35 | $274,056,242.49 | $6,580,875.92 | $26,440,374.82 | $33,021,250.74 |
| 5/1/36 | $247,035,170.93 | $6,001,831.71 | $27,021,071.56 | $33,022,903.27 |
| 11/1/36 | $219,420,649.10 | $5,410,070.24 | $27,614,521.83 | $33,024,592.07 |
| 5/1/37 | $191,199,643.32 | $4,805,312.22 | $28,221,005.78 | $33,026,318.00 |
| 11/1/37 | $162,358,833.71 | $4,187,272.19 | $28,840,809.61 | $33,028,081.80 |
| 5/1/38 | $132,884,607.82 | $3,555,658.46 | $29,474,225.89 | $33,029,884.35 |
| 11/1/38 | $102,763,054.24 | $2,910,172.91 | $30,121,553.58 | $33,031,726.49 |
| 5/1/39 | $71,979,956.04 | $2,250,510.89 | $30,783,098.20 | $33,033,609.09 |
| 11/1/39 | $40,520,784.04 | $1,576,361.04 | $31,459,172.00 | $33,035,533.04 |
| 5/1/40 | $8,370,689.98 | $887,405.17 | $32,150,094.06 | $33,037,499.23 |
| 11/1/40 | - | $183,318.11 | $8,370,689.98 | $8,554,008.09 |
| 5/1/41 | - | - | - | - |

| **SERIES 2022, TRANCHE A-3** | | | | |
|---|---|---|---|---|
| **Payment Date** | **Principal Balance** | **Interest** | **Principal** | **Total Payment** |
| 8/25/22 | $529,200,000.00 | | | |
| 5/1/23 | $529,200,000.00 | $17,046,766.80 | - | $17,046,766.80 |
| 11/1/23 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/24 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/24 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/25 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/25 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/26 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/26 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/27 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/27 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/28 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/28 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/29 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/29 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/30 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/30 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/31 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/31 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/32 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/32 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/33 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/33 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/34 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/34 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/35 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/35 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/36 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/36 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/37 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/37 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/38 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/38 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/39 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |

| | | | | |
|---|---|---|---|---|
| 11/1/39 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 5/1/40 | $529,200,000.00 | $12,473,244.00 | - | $12,473,244.00 |
| 11/1/40 | $504,714,499.48 | $12,473,244.00 | $24,485,500.52 | $36,958,744.52 |
| 5/1/41 | $471,095,814.11 | $11,896,120.75 | $33,618,685.37 | $45,514,806.12 |
| 11/1/41 | $436,682,635.16 | $11,103,728.34 | $34,413,178.95 | $45,516,907.29 |
| 5/1/42 | $401,456,186.76 | $10,292,609.71 | $35,226,448.40 | $45,519,058.11 |
| 11/1/42 | $365,397,249.31 | $9,462,322.32 | $36,058,937.45 | $45,521,259.77 |
| 5/1/43 | $328,486,149.02 | $8,612,413.17 | $36,911,100.29 | $45,523,513.46 |
| 11/1/43 | $290,702,747.16 | $7,742,418.53 | $37,783,401.86 | $45,525,820.39 |
| 5/1/44 | $252,026,429.06 | $6,851,863.75 | $38,676,318.10 | $45,528,181.85 |
| 11/1/44 | $212,436,092.86 | $5,940,262.93 | $39,590,336.20 | $45,530,599.13 |
| 5/1/45 | $171,910,138.05 | $5,007,118.71 | $40,525,954.81 | $45,533,073.52 |
| 11/1/45 | $130,426,453.60 | $4,051,921.95 | $41,483,684.45 | $45,535,606.40 |
| 5/1/46 | $87,962,405.99 | $3,074,151.51 | $42,464,047.61 | $45,538,199.12 |
| 11/1/46 | $44,494,826.77 | $2,073,273.91 | $43,467,579.22 | $45,540,853.13 |
| 5/1/47 | - | $1,048,743.07 | $44,494,826.77 | $45,543,569.84 |
| 11/1/47 | - | - | - | - |

**ATTACHMENT 2**
**SCHEDULE B**
**ESTIMATED ONGOING FINANCING COSTS**

| | **Itemized Annual Ongoing Financing Costs** |
|---|---|
| ODFA Administration Fees ^ | $186,775 |
| ODFA Legal Fees and Expenses^ | $75,000 |
| ODFA Accounting Fees^ | $75,000 |
| Trustee's/Trustee's Counsel Fees and Expenses ^ | $7,500 |
| Rating Agency Fees and Related Expenses^ | $32,000 |
| Rule 17g-5 Website ^ | $4,000 |
| Miscellaneous ^ | $50,000 |
| **Total Non-Utility External Annual Ongoing Financing Costs** | $430,275 |
| | |
| Ongoing Servicer Fees (Utility as Servicer) | $677,100 |
| Accounting Costs (External)^ | $75,000 |
| **Total (Utility as Servicer) Estimated Annual Ongoing Financing Costs** | $752,100 |
| **Ongoing Servicer Fees as % of original principal amount** | 0.056% |
| | |
| | |
| Ongoing Servicer Fees (Third-Party as Servicer - 0.60% of principal) | $8,125,200 |
| Other External Ongoing Fees (total of lines marked with a ^ mark above) | $430,275 |
| Total (Third-Party as Servicer) Estimated Ongoing Financing Costs | $8,555,475 |

**Note: The amounts shown for each category of ongoing financing costs on this attachment are the expected costs for the first year of the ratepayer-backed bonds. WESCR Charges will be adjusted at least semi-annually to reflect the actual ongoing financing costs through the true-up process described in the Financing Order, except that the servicing fee is fixed as long as the Utility (or any affiliate) is Servicer.**

**ATTACHMENT 2**
**SCHEDULE C**
**BENEFITS VERSUS CONVENTIONAL FINANCING**

| | Conventional Financing | Ratepayer-Backed Bond Financing | Savings/(Cost) of Ratepayer-Backed Bond Financing |
|---|---|---|---|
| Present Value | $2,229.3 million | $1,384.5 million | $844.8 million |

The present value discount factor shall be the rate needed to discount future debt service payments on the Bonds to the net proceeds of Bonds, including accrued interest, DSRS and any contingency retained by the trustee.

# ATTACHMENT 3

## INITIAL ALLOCATION OF COSTS TO WESCR CUSTOMER CLASSES

| (1)<br><br>WESCR Customer Classes | (2)<br>WESCR Charge[1]<br>(% of base rate revenues) | (3)<br>WESCR Charge[1,2]<br>From: 8/25/22<br>To: 5/1/23 | (4)<br>Estimated WESCR Charge[1,2]<br>From: 5/1/23<br>To: 11/1/23 |
|---|---|---|---|
| Tariffs 101 & 101-V Rate Choice A | 13.84% | $6.33 | $5.27 |
| Tariff s101 & 101-V Rate Choice B | 64.82% | $10.04 | $8.16 |
| Tariffs 200 SCI & 200 SCI-V | 6.30% | $12.61 | $10.38 |
| Tariff 200 LCI | 14.61% | $50.17 | $40.93 |
| Tariff 291S | 0.37% | $422.16 | $327.51 |
| Tariff 601S | 0.01% | $472.20 | $385.04 |
| Tariff 705 | 0.05% | $492.35 | $391.57 |
| Total | 100.00% | | |

| (1)<br><br>WESCR Customer Classes | (2)<br><br>Threshold Customer Numbers [3] |
|---|---|
| | |
| Tariffs 101 & 101-V Rate Choice A | 204,907 |
| Tariff s101 & 101-V Rate Choice B | 605,397 |
| Tariffs 200 SCI & 200 SCI-V | 47,034 |
| Tariff 200 LCI | 27,423 |
| Tariff 291S | 83 |
| Tariff 601S | 2 |
| Tariff 705 | 10 |

[1] Determined in accordance with the WESCR Mechanism Tariff at Appendix B of the Financing Order.

[2] See calculations in attached workpapers (ONG Initial WESCR Charge).

[3] These are the average customer accounts upon which WESCR Charges have been calculated. A 10% change in these customer counts will trigger a re-allocation per the WESCR Mechanism Tariff at Appendix B of the Financing Order.

**Attachment 3 - Issuance Advice Letter**

| (1) WESCR Customer Classes | (2) WESCR Charge Allocations | (3) Initial WESCR Charge [1,2] | (3) 5/1/2023 WESCR Charge Estimate [1,2] |
|---|---|---|---|
| Tariffs 101 & 101-V Rate Choice A | 13.84% | $6.33 | $5.27 |
| Tariff s101 & 101-V Rate Choice B | 64.82% | $10.04 | $8.16 |
| Tariffs 200 SCI & 200 SCI-V | 6.30% | $12.61 | $10.38 |
| Tariff 200 LCI | 14.61% | $50.17 | $40.93 |
| Tariff 291S | 0.37% | $422.16 | $327.51 |
| Tariff 601S | 0.01% | $472.20 | $385.04 |
| Tariff 705 | 0.05% | $492.35 | $391.57 |
| | | | |
| Total | 100.00% | | |

| (1) WESCR Customer Classes | (2) Threshold Customer Numbers [3] | (3) Threshold Customer Numbers [3] |
|---|---|---|
| | | |
| Tariffs 101 & 101-V Rate Choice A | 206,467 | 202,220 |
| Tariff s101 & 101-V Rate Choice B | 605,397 | 611,782 |
| Tariffs 200 SCI & 200 SCI-V | 47,191 | 46,754 |
| Tariff 200 LCI | 27,514 | 27,489 |
| Tariff 291S | 83 | 87 |
| Tariff 601S | 2 | 2 |
| Tariff 705 | 10 | 10 |

[1] Determined in accordance with the WESCR Mechanism Tariff at Appendix B of the Financing Order.

[2] See calculations in attached workpapers (ONG Initial WESCR Charge).

[3] These are the average customer counts upon which WESCR Charges have been calculated. A 10% change in these customer counts will trigger a re-allocation per the WESCR Mechanism Tariff at Appendix B of the Financing Order.

**ONG - Initial Securitization Charges Calculation**

| | September-22 | October-22 | November-22 | December-22 | January-23 | February-23 | March-23 | April-23 | | $69,256,562 | Agrees to Issuance Advice Letter | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ONG Total Tariff 101 & 101V Rate Choice A | | 208,639 | 210,001 | 210,886 | 206,381 | 206,498 | 206,584 | 206,239 | Avg Customers | | | | |
| Less Feb 2021 VFP | | (1,551) | (1,551) | (1,551) | (1,551) | (1,551) | (1,551) | (1,551) | | **# of Charges Collected** | **Allocation %** | **Allocation $** | **Initial Rate** |
| Net | 69,029 | 207,088 | 208,450 | 209,335 | 204,830 | 204,947 | 205,033 | 204,688 | 206,467 | **1,513,404** | **13.84%** | **$9,585,108** | **$6.33** |
| | | | | | | | | | | | | | |
| ONG Total Tariff 101 & 101V Rate Choice B | | 606,226 | 609,222 | 611,667 | 617,419 | 618,837 | 620,612 | 620,330 | | | | | |
| Less Feb 2021 VFP | | (4,505) | (4,505) | (4,505) | (4,505) | (4,505) | (4,505) | (4,505) | | | | | |
| Net | 200,574 | 601,721 | 604,717 | 607,162 | 612,914 | 614,332 | 616,107 | 615,825 | 610,280 | **4,473,350** | **64.82%** | **$44,892,103** | **$10.04** |
| | | | | | | | | | | | | | |
| ONG Total Tariff 200SCI & 200SCIV | | 46,334 | 46,813 | 47,169 | 48,007 | 48,227 | 48,358 | 48,083 | | | | | |
| Less Feb 2021 VFP | | (344) | (344) | (344) | (344) | (344) | (344) | (344) | | | | | |
| Net | 15,330 | 45,990 | 46,469 | 46,825 | 47,663 | 47,883 | 48,014 | 47,739 | 47,191 | **345,911** | **6.30%** | **$4,363,163** | **$12.61** |
| | | | | | | | | | | | | | |
| ONG Total Tariff 200LCI | | 26,993 | 27,274 | 27,662 | 27,545 | 27,662 | 27,777 | 27,769 | | | | | |
| Net | 8,998 | 26,993 | 27,274 | 27,662 | 27,545 | 27,662 | 27,777 | 27,769 | 27,514 | **201,680** | **14.61%** | **$10,118,384** | **$50.17** |
| | | | | | | | | | | | | | |
| ONG Total Tariff 291S | 27 | 81 | 81 | 81 | 84 | 84 | 84 | 85 | 83 | **607** | **0.37%** | **$256,249** | **$422.16** |
| ONG Total Tariff 601S | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | **15** | **0.01%** | **$6,926** | **$472.20** |
| ONG Total Tariff 705 | 3 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | **70** | **0.05%** | **$34,628** | **$492.35** |
| | | | | | | | | | | | **100.0000%** | | |

**ONG - 5/1/2023 Securitization Charges Calculation ESTIMATE**

| | May-23 | June-23 | July-23 | August-23 | September-23 | October-23 | | 46,204,828 | Agrees to Issuance Advice Letter | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ONG Total Tariff 101 & 101V Rate Choice A | 205,626 | 204,497 | 203,773 | 202,825 | 202,825 | 202,825 | Avg Customers | | | | |
| Less Feb 2021 VFP | (1,508) | (1,508) | (1,508) | (1,508) | (1,508) | (1,508) | | # of Charges Collected | Allocation % | Allocation $ | Initial Rate |
| Net | 204,118 | 202,989 | 202,265 | 201,317 | 201,317 | 201,317 | 202,220 | 1,213,323 | 13.84% | $6,394,748 | $5.27 |
| | | | | | | | | | | | |
| ONG Total Tariff 101 & 101V Rate Choice B | 619,226 | 616,649 | 615,383 | 615,560 | 615,560 | 615,560 | | | | | |
| Less Feb 2021 VFP | (4,541) | (4,541) | (4,541) | (4,541) | (4,541) | (4,541) | | | | | |
| Net | 614,685 | 612,108 | 610,842 | 611,019 | 611,019 | 611,019 | 611,782 | 3,670,691 | 64.82% | $29,949,970 | $8.16 |
| | | | | | | | | | | | |
| ONG Total Tariff 200SCI & 200SCIV | 47,830 | 47,322 | 46,936 | 46,846 | 46,846 | 46,846 | | | | | |
| Less Feb 2021 VFP | (351) | (351) | (351) | (351) | (351) | (351) | | | | | |
| Net | 47,479 | 46,971 | 46,585 | 46,495 | 46,495 | 46,495 | 46,754 | 280,521 | 6.30% | $2,910,904 | $10.38 |
| | | | | | | | | | | | |
| ONG Total Tariff 200LCI | 27,685 | 27,512 | 27,430 | 27,436 | 27,436 | 27,436 | | | | | |
| Net | 27,685 | 27,512 | 27,430 | 27,436 | 27,436 | 27,436 | 27,489 | 164,935 | 14.61% | $6,750,525 | $40.93 |
| | | | | | | | | | | | |
| ONG Total Tariff 291S | 87 | 87 | 87 | 87 | 87 | 87 | 87 | 522 | 0.37% | $170,958 | $327.51 |
| ONG Total Tariff 601S | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 12 | 0.01% | $4,620 | $385.04 |
| ONG Total Tariff 705 | 9 | 10 | 10 | 10 | 10 | 10 | 10 | 59 | 0.05% | $23,102 | $391.57 |
| | | | | | | | | | 100.0000% | | |

## ATTACHMENT 4

## UTILITY CERTIFICATION

THE OKLAHOMA CORPORATION COMMISSION
ATTN: Chair
Jim Thorpe Office Building
2101 N. Lincoln Boulevard
Oklahoma City, Oklahoma 73105

Pursuant to the Final Financing Order issued on the 25th day of January, 2022 in Cause No. PUD 202100079 before the Oklahoma Corporation Commission, *Application of Oklahoma Natural Gas Company, a Division of One Gas, Inc. for a Financing Order Approving Securitization of Costs Arising from the February 2021 Winter Weather Event Pursuant to the "February 2021 Regulated Utility Consumer Protection Act"* (the "Financing Order"), THE OKLAHOMA NATURAL GAS COMPANY (the "Utility" or the "Applicant") certifies that the calculation of the WESCR Charges included in the Issuance Advice Letter were calculated in accordance with Financing Order. If the Commission determines that the calculation of the WESCR Charges contained any mathematical error, such error will be corrected upon the next implementation of the true-up and reconciliation process.

Any capitalized terms not defined in this certification shall have the meanings ascribed to them in the Financing Order or the February 2021 Regulated Utility Consumer Protection Act, 74 Okla. Stat. §§ 9071-9081.

Respectfully submitted,

OKLAHOMA NATURAL GAS COMPANY, a
Division of ONE Gas, Inc.

By: Caron A. Lawhorn
Name: Caron A. Lawhorn
Title: Senior Vice President and Chief Financial Officer

cc: Director of the Public Utility Division, Oklahoma Corporation Commission

ONE GAS
BKS
LEGAL APPROVED

*Signature Page to Utility Certification*

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

November 5, 2021

**Advice 6390-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**<u>Subject:</u>** **Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission (CPUC) Decision (D.) 21-06-030 (the Financing Order), Pacific Gas and Electric Company (PG&E) hereby transmits for submission, within one day after the pricing date of this series of Wildfire Hardening Recovery Bonds, the initial Fixed Recovery Charges for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series 2021-A, Tranche(s) A-1, A-2 and A-3 (Recovery Bonds).

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto is the Finance Team's pre-issuance approval letter dated November 4, 2021.

## Purpose

This submission establishes initial Fixed Recovery Charges for rate schedules for Consumers. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner (Special Purpose Entity or SPE), including the Billing Commencement Date. Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Upfront Financing Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In the Financing Order, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the rate design methodology and Fixed Recovery Charge cash flow formula found reasonable by the Commission in the Financing Order to establish initial Fixed Recovery Charges for a series of Recovery Bonds. Using this methodology and formula approved by the Commission in the Financing Order, this submission establishes the initial Fixed Recovery Charges.

## Issuance Information

The Financing Order requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2021-A
Recovery Property Owner (SPE): PG&E Recovery Funding LLC
Bond Trustee: The Bank of New York Mellon Trust Company, N.A.
Closing Date: 11/12/2021
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued (Authorized Amount): $860,399,000.00 (See Table 1 below)

Upfront Financing Costs: $10,351,000.00 (See Table 2 below)
Upfront Financing Costs as a Percent of Principal Amount Issued: 1.2%
Coupon Rate(s): See Exhibit 1
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): See Exhibit 1
Legal Maturity Date(s): See Exhibit 1
Payment Dates (semi-annually): January 15 and July 15
Annual Servicing Fee as a percent of the issuance amount: 0.05%
Annual Administration Fee: $75,000
Overcollateralization amount for the series, if any: None

FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: December 1, 2021
First Payment Period: Closing Date through and including First Payment Date
Second Payment Period: Day following First Payment Date through and including Second Payment Date

**<u>Securitized Amount</u>**

The following table sets for the computation of the final Securitized Amount (i.e., the principal amount of the Recovery Bonds).

| **Table 1: Securitized Amount** | |
|---|---|
| Initial AB 1054 CapEx Amount:<br>• 2020<br>• 2021 | $609,155,000<br>$240,893,000 |
| Upfront Financing Costs (See Table 2 below) | $10,351,000 |
| Total Securitized Amount | $860,399,000 |

PG&E has determined that the Community Wildfire Safety Program (CWSP) system hardening costs to be recovered through the issuance of Recovery Bonds described herein do not exceed 115 percent of the Commission-approved per-mile costs set forth in D.20-12-005 at page 119.

**Upfront Financing Costs**

The following table includes actual or estimated (as noted) Upfront Financing Costs to be incurred in connection with the issuance of the Recovery Bonds:

| **Table 2: Upfront Financing Costs** | |
|---|---|
| Underwriters' Fees and Expenses | $3,441,596 |
| Legal Fees and Expenses | $3,523,734 |
| Rating Agency Fees | $989,459 |
| Accounting Fees and Expenses | $125,000 |
| Company's Advisory Fee | $255,000 |
| Servicer Set-up Costs | $3,000 |
| SEC Registration Fees | $94,135 |
| Section 1904 Fees | $436,200 |
| Printing / EDGARizing Expenses | $40,000 |
| Trustee / Trustee Counsel Fee and Expenses | $52,000 |
| Original Issue Discount | $28,104 |
| Commission's Costs and Expenses | $1,219,500 |
| Miscellaneous | $143,272 |
| | |
| **Total** | **$10,351,000** |
| **Note 1:** Section 1904 Fees computed in accordance with Decision 21-06-030 | |

**True-Up Mechanism**

Changes to the Fixed Recovery Charges will be requested through the submission of Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters in accordance with the Financing Order. Annually before each FRC Annual Adjustment Date (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of Recovery Bonds), semi-annually, if required by the servicer, and more frequent as required by the servicer, the servicer will submit Routine True-Up Mechanism Advice Letters in the form of Attachment 3 to the Financing Order to ensure that Fixed Recovery Charges collections are sufficient to make all scheduled payments of bond principal, interest, and other Ongoing Financing Costs on a timely basis during each of the two payment periods and, in the case of semi-annual Routine True-Up Mechanism Advice Letter, to replenish any draws upon the capital subaccount. The first payment period means the period commencing on the Closing Date and ending (and including) the first Payment Date following the Closing Date (the "First Payment Period"); the second payment period means the period commencing on the day following the first Payment Date and ending (and including) the next Payment Date (the "Second Payment Period"). The servicer may also submit Non-Routine True-Up Mechanism Advice Letters in the form of Attachment 4 to the Financing Order.

**Ongoing Financing Costs**

The following table includes estimated Ongoing Financing Costs for the First and Second Payment periods following Closing Date to be recovered through Fixed Recovery Charges in accordance with the Financing Order.

| TABLE 3: Estimated Ongoing Financing Costs | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $272,460 | $215,100 |
| Administration Fee | $47,500 | $37,500 |
| Accounting Fees and Expenses | $37,500 | $37,500 |
| Legal Fees and Expenses | $17,500 | $17,500 |
| Rating Agency Surveillance Fees | $20,000 | $20,000 |
| Trustee Fees and Expenses | $2,100 | $2,100 |
| Independent Director Fees | $1,500 | $1,500 |
| Printing / EDGARizing Expenses | $5,000 | $5,000 |
| Return on Equity | $62,659 | $49,467 |
| Miscellaneous Fees and Expenses | $5,000 | $5,000 |
| | | |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$471,219** | **$390,667** |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of initial principal amount) | $3,269,516 | $2,581,197 |
| **TOTAL ONGOING FINANCING COSTS (Third Party as Servicer)** | **$3,468,275** | **$2,756,764** |

**Fixed Recovery Charges**

Table 4 below shows the inputs and current assumptions for each of the variables used in calculating the Fixed Recovery Charges:

| TABLE 4: Input Values For Fixed Recovery Charges | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Allocation Factors for each Customer Class (see Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Projected kWh sales for each Customer Class for payment period (See Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Percent of Consumers' revenue written off | 0.34% | 0.34% |
| Average Days Sales Outstanding | 55 | 55 |
| Ongoing Financing Costs for the applicable payment period (See Table 3 above) | $471,219 | $390,667 |
| Recovery Bond Principal | $18,365,684.46 | $13,530,457.77 |
| Recovery Bond Interest | $13,356,181.30 | $9,759,398.13 |
| Periodic Payment Requirement (See Exhibit 2) | $32,193,084.39 | $23,680,523.24 |
| Periodic Billing Requirement (See Exhibit 3) | $32,193,084.39 | $23,680,523.24 |

Table 5 shows the initial Fixed Recovery Charges for each FRC Consumer Class:

| TABLE 5: Fixed Recovery Charges (cent per kWh) | |
|---|---|
| **FRC Consumer Class** | **WHC*** |
| **Bundled Service** | |
| Residential | 0.106 |
| Residential – CARE | - |
| Residential – Non-CARE | 0.141 |
| Small Commercial | 0.145 |
| Medium Commercial | 0.115 |
| Medium Commercial – A/B-10T | 0.080 |
| Medium Commercial – A/B-10P | 0.109 |
| Medium Commercial – A/B-10S | 0.120 |
| E/B-19 | 0.103 |
| E/B-19T | 0.080 |
| E/B-19P | 0.092 |
| E/B-19S | 0.102 |
| Streetlight | 0.123 |
| Standby | 0.076 |
| Standby – STOU T | 0.072 |
| Standby – STOU P | 0.288 |
| Standby – STOU S | 0.146 |
| Agriculture | 0.128 |
| E/B-20 | 0.074 |
| E/B-20 T | 0.055 |
| E/B-20 P | 0.084 |
| E/B-20 S | 0.093 |
| Average Bundled Rate | 0.106 |
| **Direct Access/Community Choice Aggregation (DA/CCA)** | |
| Residential | 0.106 |
| Residential – CARE | - |

| | |
|---|---|
| Residential – Non-CARE | 0.141 |
| Small Commercial | 0.145 |
| Medium Commercial | 0.115 |
| Medium Commercial – A/B-10T | 0.080 |
| Medium Commercial – A/B-10P | 0.109 |
| Medium Commercial – A/B-10S | 0.120 |
| E/B-19 | 0.103 |
| E/B-19T | 0.080 |
| E/B-19P | 0.092 |
| E/B-19S | 0.102 |
| Streetlight | 0.123 |
| Standby | 0.076 |
| Standby – STOU T | 0.072 |
| Standby – STOU P | 0.288 |
| Standby – STOU S | 0.146 |
| Agriculture | 0.128 |
| E/B-20 | 0.074 |
| E/B-20 T | 0.055 |
| E/B-20 P | 0.084 |
| E/B-20 S | 0.093 |
| Average DA/CCA Rate | 0.106 |

**Class average rates are calculated by dividing total revenues expected to be collected by the WHC by total forecasted system sales for the class for the rate effective period.*

**Recovery Property**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charges set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charges set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 2, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charges, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charges under the True-Up Mechanism.

These Fixed Recovery Charges, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 2 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Proposed Tariff Changes**

PG&E will submit all tariff sheets reflecting the revised Fixed Recovery Charges shown in Table 5 in the consolidated revenue requirement and rate change advice letter for a rate effective date of December 1, 2021.

**Description of Exhibits**

Exhibit 1 presents the debt service schedule for the Recovery Bonds, including expected principal amortization, scheduled final payment dates and final maturity dates, interest rates, and aggregate scheduled debt service per payment date.

Exhibit 2 presents the Periodic Payment Requirements related to the Recovery Bonds for the two payment periods following the Closing Date.

Exhibit 3 presents the Fixed Recovery Charges calculations.

**Effective Date**

In accordance with the Financing Order, unless before noon on the fourth business day after pricing the Commission Staff rejects this Issuance Advice Letter for failure to adhere to the terms of the Financing Order, the Issuance Advice Letter and the Fixed Recovery Charges established by this Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charges will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes. Further all Upfront Financing Costs and all Ongoing Financing Costs for the life of the Recovery Bonds shall be recoverable as provided in the Financing Order.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.21-02-020. Address changes should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: https://www.pge.com/tariffs/advice-letters.page.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

**Attachments**

Attachment 1: Exhibits 1-3
Attachment 2: Pre-Issuance Approval Letter

cc: Service List A.21-02-020

California Public Utilities Commission

# ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (U 39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Stuart Rubio
Phone #: (415) 973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: SHR8@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6390-E

Tier Designation: 1

Subject of AL: Issuance Advice Letter Submission for Recovery Bonds

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-06-030

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: N/A

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

| | |
|---|---|
| CPUC, Energy Division<br>Attention: Tariff Unit<br>505 Van Ness Avenue<br>San Francisco, CA 94102<br>Email: EDTariffUnit@cpuc.ca.gov | Name: Sidney Bob Dietz II, c/o Megan Lawson<br>Title: Director, Regulatory Relations<br>Utility Name: Pacific Gas and Electric Company<br>Address: 77 Beale Street, Mail Code B13U<br>City: San Francisco, CA 94177<br>State: California Zip: 94177<br>Telephone (xxx) xxx-xxxx: (415)973-2093<br>Facsimile (xxx) xxx-xxxx: (415)973-3582<br>Email: PGETariffs@pge.com |
| | Name:<br>Title:<br>Utility Name:<br>Address:<br>City:<br>State: District of Columbia Zip:<br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: |

Clear Form

Advice 6390-E
November 5, 2021

# Attachment 1

# Exhibits 1-3

**Exhibit 1**
**Recovery Bond Terms and Debt Service Schedule**

| Tranche | Expected Weighted Average Life | Principal Amount Offered | Scheduled Final Payment Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|---|
| A-1 | 4.99 | $266,127,000 | 7/15/2031 | 7/15/2033 | 1.460% |
| A-2 | 11.99 | $160,309,000 | 1/15/2036 | 1/15/2038 | 2.280% |
| A-3 | 19.93 | $433,963,000 | 7/15/2046 | 7/15/2048 | 2.822% |
| | | $860,399,000 | | | |

**Tranche A-1**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/12/2021 | $266,127,000 | | | |
| 7/15/2022 | $247,761,316 | $18,365,684 | $2,622,682 | $20,988,366 |
| 1/15/2023 | $234,230,858 | $13,530,458 | $1,808,658 | $15,339,115 |
| 7/15/2023 | $220,592,427 | $13,638,431 | $1,709,885 | $15,348,316 |
| 1/15/2024 | $206,845,161 | $13,747,265 | $1,610,325 | $15,357,590 |
| 7/15/2024 | $192,988,193 | $13,856,969 | $1,509,970 | $15,366,938 |
| 1/15/2025 | $179,020,645 | $13,967,547 | $1,408,814 | $15,376,361 |
| 7/15/2025 | $164,941,637 | $14,079,008 | $1,306,851 | $15,385,859 |
| 1/15/2026 | $150,750,278 | $14,191,359 | $1,204,074 | $15,395,433 |
| 7/15/2026 | $136,445,673 | $14,304,606 | $1,100,477 | $15,405,083 |
| 1/15/2027 | $122,026,916 | $14,418,757 | $996,053 | $15,414,810 |
| 7/15/2027 | $107,493,098 | $14,533,818 | $890,796 | $15,424,615 |
| 1/15/2028 | $92,843,300 | $14,649,798 | $784,700 | $15,434,498 |
| 7/15/2028 | $78,076,596 | $14,766,704 | $677,756 | $15,444,460 |
| 1/15/2029 | $63,192,054 | $14,884,542 | $569,959 | $15,454,501 |
| 7/15/2029 | $48,188,734 | $15,003,320 | $461,302 | $15,464,622 |
| 1/15/2030 | $33,065,687 | $15,123,047 | $351,778 | $15,474,825 |
| 7/15/2030 | $17,821,958 | $15,243,729 | $241,380 | $15,485,108 |
| 1/15/2031 | $2,456,584 | $15,365,374 | $130,100 | $15,495,474 |
| 7/15/2031 | $0 | $2,456,584 | $17,933 | $2,474,517 |

**Exhibit 1**
**Tranche A-2**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/12/2021 | $160,309,000 | | | |
| 7/15/2022 | $160,309,000 | $0 | $2,467,156 | $2,467,156 |
| 1/15/2023 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2023 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2024 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2024 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2025 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2025 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2026 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2026 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2027 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2027 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2028 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2028 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2029 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2029 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2030 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2030 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 1/15/2031 | $160,309,000 | $0 | $1,827,523 | $1,827,523 |
| 7/15/2031 | $147,277,594 | $13,031,406 | $1,827,523 | $14,858,928 |
| 1/15/2032 | $131,599,225 | $15,678,370 | $1,678,965 | $17,357,334 |
| 7/15/2032 | $115,715,390 | $15,883,835 | $1,500,231 | $17,384,066 |
| 1/15/2033 | $99,623,398 | $16,091,992 | $1,319,155 | $17,411,148 |
| 7/15/2033 | $83,320,520 | $16,302,878 | $1,135,707 | $17,438,585 |
| 1/15/2034 | $66,803,993 | $16,516,527 | $949,854 | $17,466,381 |
| 7/15/2034 | $50,071,017 | $16,732,976 | $761,566 | $17,494,542 |
| 1/15/2035 | $33,118,755 | $16,952,262 | $570,810 | $17,523,071 |
| 7/15/2035 | $15,944,334 | $17,174,421 | $377,554 | $17,551,975 |
| 1/15/2036 | $0 | $15,944,334 | $181,765 | $16,126,099 |

**Exhibit 1**
**Tranche A-3**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/12/2021 | $433,963,000 | | | |
| 7/15/2022 | $433,963,000 | $0 | $8,266,344 | $8,266,344 |
| 1/15/2023 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2023 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2024 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2024 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2025 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2025 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2026 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2026 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2027 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2027 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2028 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2028 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2029 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2029 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2030 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2030 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2031 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2031 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2032 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2032 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2033 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2033 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2034 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2034 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2035 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 7/15/2035 | $433,963,000 | $0 | $6,123,218 | $6,123,218 |
| 1/15/2036 | $432,507,842 | $1,455,158 | $6,123,218 | $7,578,376 |
| 7/15/2036 | $414,877,222 | $17,630,619 | $6,102,686 | $23,733,305 |
| 1/15/2037 | $396,977,913 | $17,899,310 | $5,853,918 | $23,753,227 |
| 7/15/2037 | $378,805,817 | $18,172,095 | $5,601,358 | $23,773,454 |
| 1/15/2038 | $360,356,779 | $18,449,038 | $5,344,950 | $23,793,988 |
| 7/15/2038 | $341,626,578 | $18,730,201 | $5,084,634 | $23,814,835 |
| 1/15/2039 | $322,610,929 | $19,015,650 | $4,820,351 | $23,836,001 |
| 7/15/2039 | $303,305,481 | $19,305,448 | $4,552,040 | $23,857,488 |
| 1/15/2040 | $283,705,817 | $19,599,663 | $4,279,640 | $23,879,303 |
| 7/15/2040 | $263,807,455 | $19,898,362 | $4,003,089 | $23,901,451 |
| 1/15/2041 | $243,605,842 | $20,201,613 | $3,722,323 | $23,923,936 |
| 7/15/2041 | $223,096,357 | $20,509,486 | $3,437,278 | $23,946,764 |
| 1/15/2042 | $202,274,307 | $20,822,050 | $3,147,890 | $23,969,940 |
| 7/15/2042 | $181,134,928 | $21,139,378 | $2,854,090 | $23,993,469 |
| 1/15/2043 | $159,673,386 | $21,461,542 | $2,555,814 | $24,017,356 |
| 7/15/2043 | $137,884,770 | $21,788,616 | $2,252,991 | $24,041,608 |
| 1/15/2044 | $115,764,095 | $22,120,675 | $1,945,554 | $24,066,229 |
| 7/15/2044 | $93,306,301 | $22,457,794 | $1,633,431 | $24,091,225 |
| 1/15/2045 | $70,506,251 | $22,800,051 | $1,316,552 | $24,116,603 |
| 7/15/2045 | $47,358,727 | $23,147,523 | $994,843 | $24,142,367 |
| 1/15/2046 | $23,858,436 | $23,500,292 | $668,232 | $24,168,523 |
| 7/15/2046 | $0 | $23,858,436 | $336,643 | $24,195,078 |

**Exhibit 2**
**Periodic Payment Requirements**

The total amount payable to the owner of the Recovery Property, or its assignee(s), pursuant to this issuance advice letter is a $860,399,000 principal amount, plus interest on such principal amount, plus Ongoing Financing Costs, to be obtained from Fixed Recovery Charges calculated in accordance with the Decision.

The Fixed Recovery Charges shall be adjusted from time to time, at least annually, via the Routine True-Up Mechanism Advice Letter and Non-Routine True-Up Mechanism Advice Letter in accordance with the Decision.

The following amounts are scheduled to be paid by the Bond Trustee from Fixed Recovery Charges it has received during the two Payment Periods following the Closing Date. These payment amounts include principal plus interest and plus other Ongoing Financing Costs.

| Payment Period | Recovery Bond Payments (See Exhibit 1) | Ongoing Financing Costs (see Table 3) | Periodic Payment Requirement |
|---|---|---|---|
| **First Payment Period** | $31,721,865.76 | $471,218.63 | $32,193,084.39 |
| **Second Payment Period** | $23,289,855.90 | $390,667.34 | $23,680,523.24 |

**Exhibit 3**
**Fixed Recovery Charges Calculations**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) = (F) x (B) / (C) |
|---|---|---|---|---|---|---|
| FRC Consumer Class | WHFRC Allocation Factors for Effective Period[1] | WHFRC Sales Factors for Effective Period[1] | Highest Periodic Billing Requirement ($) | Forecasted Billed and Collected Sales for Highest Periodic Requirement (MWh) | System Average WHFRC (¢/kWh) | New WHFRC (¢/kWh) |
| Residential - CARE [2] | 0.0% | 0.0% | 32,193,084 | 0 | 0.116 | - |
| Residential - Non-CARI | 36.9% | 30.6% | 32,193,084 | 8,930,776 | 0.116 | 0.141 |
| Small Commercial | 13.5% | 10.8% | 32,193,084 | 2,982,896 | 0.116 | 0.145 |
| A/B-10T | 0.002% | 0.003% | 32,193,084 | 1,030 | 0.116 | 0.080 |
| A/B-10P | 0.1% | 0.1% | 32,193,084 | 24,305 | 0.116 | 0.109 |
| A/B-10S | 11.1% | 10.8% | 32,193,084 | 2,995,495 | 0.116 | 0.120 |
| E/B-19T | 0.03% | 0.04% | 32,193,084 | 13,688 | 0.116 | 0.080 |
| E/B-19P | 1.2% | 1.5% | 32,193,084 | 436,981 | 0.116 | 0.092 |
| E/B-19S | 15.2% | 17.4% | 32,193,084 | 4,814,610 | 0.116 | 0.102 |
| Streetlight | 0.3% | 0.3% | 32,193,084 | 98,795 | 0.116 | 0.123 |
| Standby - STOU T | 0.3% | 0.4% | 32,193,084 | 134,114 | 0.116 | 0.072 |
| Standby - STOU P | 0.1% | 0.02% | 32,193,084 | 6,298 | 0.116 | 0.288 |
| Standby - STOU S | 0.01% | 0.01% | 32,193,084 | 2,574 | 0.116 | 0.146 |
| Agriculture | 8.6% | 7.8% | 32,193,084 | 1,568,412 | 0.116 | 0.128 |
| E/B-20T | 3.7% | 8.0% | 32,193,084 | 2,270,668 | 0.116 | 0.055 |
| E/B-20P | 6.4% | 8.9% | 32,193,084 | 2,515,717 | 0.116 | 0.084 |
| E/B-20S | 2.6% | 3.3% | 32,193,084 | 926,166 | 0.116 | 0.093 |

[1] Effective Period is 12/1/2021 through 2/28/2023 and is defined as the time period in which these Wildfire Hardening Fixed Recovery Charges will be collected in rates.

[2] CARE customers are exempt from paying the fixed recovery charge.

# Attachment 2

# Pre-Issuance Approval Letter

STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 4, 2021

**Via Electronic Mail**

Margaret K. Becker
Vice President and Treasurer
Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000
San Francisco, CA 94177
MKBd@pge.com .

**Subject: Pre-Issuance Approval Letter for PG&E Senior Secured Recovery Bonds Series 2021-A, Tranches A-1 through A-3 (Recovery Bonds)**

Dear Ms. Becker,

Pursuant to Ordering Paragraph 4 of California Public Utilities Commission (CPUC) Decision D.21-06-030 (the Decision), the Commission Finance Team, consisting of Edward Randolph, Arocles Aguilar, and their designated representatives, provides this letter evidencing the Finance Team's pre-issuance review and approval of Pacific Gas and Electric Company's (PG&E's) issuance of recovery bonds authorized by the Decision, the terms of which are set forth in the Draft Issuance Advice Letter for the Senior Secured Recovery Bonds, Series 2021-A, Tranches A-1 through A-3 (Recovery Bonds), attached hereto as Exhibit A (the Draft Issuance Advice Letter). As set forth below, the Finance Team confirms it has completed its pre-issuance review of and approves the material terms of the Recovery Bonds as presented in the Draft Issuance Advice Letter.

In accordance with the Decision, the final terms and structure of the Recovery Bonds, including the recovery of the upfront financing costs and all ongoing financing costs for the life of the Recovery Bonds, as well as the initial fixed recovery charges, are to be approved through the Issuance Advice Letter process as provided in the Decision.

**FINANCE TEAM REVIEW AND APPROVAL**

## I. COMMISSION AUTHORITY FOR APPROVING STRUCTURE AND TERMS FOR RECOVERY BONDS

On February 24, 2021, PG&E submitted an application under California Public Utilities Code Section 850 et seq.[1] seeking the Commission's approval of a proposed financing order for PG&E's issuance of Recovery Bonds to finance fire risk mitigation capital expenditures and related costs and expenses. Specifically, PG&E requested authority to issue Recovery Bonds for approximately $1.2 billion, along with upfront financing costs.

The Commission reviewed PG&E's request, considered comments filed by stakeholders who were parties to the docket (A.21-02-020), issued a financing order, and granted PG&E's request to allow PG&E to submit an Issuance Advice Letter when final terms and structure for the Recovery Bonds have been established.[2] The Issuance Advice Letter is to include the critical details and final terms of the proposed Recovery Bonds and set forth the cost allocation, rate design methodology, and Fixed Recovery Charge cash flow formula authorized by the Commission to establish initial Fixed Recovery Charges for a series of Recovery Bonds.

## II. ESTABLISHMENT OF A FINANCE TEAM

The Decision provides for, among other tools, "employing the review and approval of the Finance Team … [to] reduce, to the maximum extent possible, the rates to Consumers on a present value basis,"[3] which is consistent with the statutory mandate that "[t]he recovery of recovery costs through the designation of the fixed recovery charges and any associated fixed recovery tax amounts, and the issuance of recovery bonds in connection with the fixed recovery charges, would reduce, to the maximum extent possible, the rates on a present value basis that consumers within the electrical corporation's service territory would pay as compared to the use of traditional utility financing mechanisms, which shall be calculated using the electrical corporation's corporate debt and equity in the ratio approved by the Commission at the time of the financing order."[4]

Ordering Paragraph 4 of the Decision provides that:

> The Finance Team's pre-issuance review and approval of the material terms and structure of a series of Recovery Bonds shall be evidenced by an approval letter from the Finance Team to Pacific Gas and Electric

---

[1] On July 12, 2019, Governor Newsom signed into law Assembly Bill (AB) No. 1054, which amended Division 1, Part 1, Chapter 4, Article 5.8, commencing with § 850 of the Public Utilities Code. Public Utilities Code Article 5.8 was later amended by AB 1513 and AB 913 and authorizes the issuance of Recovery Bonds.

[2] Decision Ordering ¶ 1.

[3] Decision Findings of Fact ¶ 3.

[4] Public Utilities Code § 850.1(a)(1)(A)(ii)(III).

> Company (PG&E) delivered on or before the date of the pricing of the relevant Recovery Bonds. PG&E shall be required to include such a draft approval letter as an attachment to the Issuance Advice Letter relating to such series of Recovery Bonds, or as a supplement to such Issuance Advice Letter. Such approval letter from the Finance Team to PG&E shall be a condition precedent to the issuance of such a series of Recovery Bonds.

Consistent with the Decision, the Commission established a Finance Team consisting of the Commission's Director of Energy Division, Edward Randolph (who also serves as the Deputy Executive Director for Energy and Climate Policy), the Commission's General Counsel, Arocles Aguilar, and additional designated representatives from Commission Staff. The Finance Team also included Ducera Partners LLC, as Financial Advisor, and Paul, Weiss, Rifkind, Wharton & Garrison LLP, as the Finance Team Legal Advisor.

## III. PG&E'S ACTIVITIES

In accordance with the Financing Order, PG&E undertook a number of activities in arranging for the issuance of the Recovery Bonds. In addition to the specific activities discussed in the following section, PG&E has represented that it has undertaken the following activities:

- Responded to all Finance Team inquiries and comments and incorporated Finance Team input.
- Registered the Recovery Bonds with the Securities and Exchange Commission to facilitate greater liquidity, identified the bonds as not "asset-backed securities" as such term is defined by the SEC in governing regulations Item 1101 of Regulation AB and marketed the Recovery Bonds to ABS and corporate bond investors.
- After receiving the advice of the underwriters, selected, applied for and received preliminary Aaa(sf)/AAA(sf) ratings from two of the major rating agencies with final Aaa(sf)/AAA(sf) ratings as a condition of closing.
- Provided preliminary prospectus by e-mail to prospective investors.
- Allowed sufficient time for investors to review the preliminary prospectus and to ask questions regarding the transaction.
- Arranged for the issuance of rating agency pre-sale reports during the marketing period.
- During the period that the Recovery Bonds were marketed, PG&E held frequent market update discussions with the underwriting team to discuss market conditions and develop strategy for pricing.

- Had multiple conversations with all members of the underwriting team before and during the marketing phase in which PG&E stressed the requirements of the Financing Order.
- Conducted roadshow meetings with investors to provide information on the offering.
- Provided potential investors with access to an internet roadshow for viewing at investors' convenience.
- Adapted the Recovery Bond offering to market conditions and investor demand at the time of marketing. Variables impacting the final structure of the transaction were evaluated including the tranche structure, term, length of weighted average lives, issuance size, amortization schedules, credit protections and maturity of the Recovery Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order.
- With consideration to input from and the approval of the Finance Team and underwriters (and each of their respective counsels), finalized documentation in accordance with established standards for transactions of this sort and the terms of the Financing Order.

## IV. FINANCE TEAM REVIEW

The Finance Team met periodically with PG&E representatives, via teleconference, from June 2021 through November 2021, to address subjects such as: (1) the underwriter and syndication group size, selection process, participants, allocations, and economics, which involved a Request for Proposal (RFP) process, obtaining a broad view of transaction structure alternatives from potential underwriters and proposals from a broad set of traditional and diverse banks; (2) the structure of the Recovery Bonds, including considerations reviewed or proposed during the RFP process and recommendations from PG&E and its lead underwriters, including on parameters to drive the greatest level of investor interest and resulting savings to ratepayers; (3) the Recovery Bonds' credit rating agency applications, supporting materials and preliminary AAA/Aaa results; (4) the underwriters' preparation, proposed marketing, marketing materials, and proposed syndication of the Recovery Bonds; (5) the proposed pricing approach of the Recovery Bonds and certifications to be provided by PG&E and the lead underwriters (with ongoing review and involvement in the pricing process); (6) all associated Recovery Bond costs (including Upfront Financing Costs and other Financing Costs), servicing and administrative fees and associated crediting as well as a comparison of such costs relative to other issuances, (7) maturities, weighted average lives and alternative structures, (8) reporting templates, (9) the amount of PG&E's equity contribution to the related SPE, (10) overcollateralization and other credit enhancements and (11) the initial calculation of the related Fixed Recovery Charges. The Finance Team also met both with PG&E and without PG&E to evaluate PG&E's proposals and to conduct due diligence, including reviewing the validity of PG&E's assumptions, evaluating potential modifications, and developing recommended paths forward. In accordance with the Decision, the Finance Team's review included the following:

**1. Recovery Bonds Structure**

Pursuant to the Decision, the Finance Team was provided the right to review all material terms of the recovery bonds and other items the Finance Team determined were appropriate to perform its reviewing role.[5] With the benefit of preliminary structures proposed by potential underwriters in the RFP process, the Finance Team considered and made inquiries about PG&E's proposed structure, proposed structuring parameters and proposed alternatives. The Finance Team discussed parameters to maximize potential net present value savings and available transaction alternatives and provided comments and input, which were incorporated into the recovery bond structure. After conducting its review, the Finance Team accepted the proposed transaction structure, including three tranches of Recovery Bonds, a maturity profile that did not exceed the average useful life of the amounts securitized,[6] and structural elements designed to appeal to the broadest range of investors possible. The proposed transaction structure was found to be appropriate subject to modification, if required, as part of the marketing process to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the rates that would be paid using traditional utility financing mechanisms.

**2. Recovery Bonds Lead Advisor and Underwriters**

Pursuant to the Decision, the Finance Team was provided the right to oversee the process of selecting underwriters for the Recovery Bonds.[7] Accordingly, the Finance Team engaged in several meetings with PG&E to inquire about PG&E's RFP and the responses received. The Finance Team requested PG&E obtain supplemental proposals from a select group of underwriters, including more detailed views around structuring, marketing and pricing from such prospective underwriters. As part of this supplemental process, the Finance Team requested PG&E obtain potential underwriters views of various important elements of the process, including optimal structure (tranches, term, size), features by issuance, marketing (including investors by tranche), how the underwriters would tell the story, views of relevant pricing of comparable deals, proposed fees and costs, anticipated investor concerns and how they would be addressed, as well as views of optimal timing of the marketing process and optimal syndication strategies.

Through the underwriter selection process, the Finance Team encouraged broad participation in the RFP process, assessed all prospective underwriter views on recovery bond structures to assist in achieving optimal execution, including reviewing proposed term sheets, views on

---

[5] Decision, Ordering ¶ 3.

[6] Order paragraph 5 requires approval of the scheduled final payment date of the latest maturing tranche of the Recovery Bonds.

[7] Decision, Ordering ¶ 3.

key components of the structure, additional structural elements such as green bond certifications, proposed investor lists, the proposed cost structure, proposed underwriting and advisory fees, and views on pricing to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms. This informed the choice of underwriters to lead the transaction while ensuring that optimal deal factors were incorporated into the transaction. Based on information provided by PG&E, the Finance Team approved the selection of underwriters.

The underwriter group was expanded with additional traditional and diverse banks to supplement the underwriter group's experience and to include experience with transactions marketed to both ABS and corporate investors.

Underwriter economics were reviewed with PG&E, including review of comparable issuances and the role and scope of this process. Such fees were determined shortly ahead of marketing, as determined by PG&E to be appropriate, including encouraging the ongoing support from its underwriters.

### 3. Credit Rating Agency Review

Pursuant to the Decision, the Finance Team was directed to review the credit rating agency applications associated with the Recovery Bonds.[8] PG&E provided the Finance Team with access to all information provided to the rating agencies, including previewing information with the Finance Team. All aspects of the process, including confidential information shared with the rating agencies and all related disclosures were also made available to the Finance Team. The Finance Team reviewed the credit rating process, related materials, call notes, and the approach to presentations and the application for credit ratings. With the Finance Team's input on certain information shared with credit ratings, PG&E applied for and received preliminary "triple-A" ratings from two of the major rating agencies with final ratings of Aaa(sf)(Moody's)/AAA(sf)(S&P) expected to be confirmed at closing.

PG&E also reviewed potential green bond certification options with the Finance Team, including potential certification providers, the associated costs and potential benefits of obtaining such a certification. The Finance Team approved the green bond certification, which was obtained to further broaden potential investors and resulting potential customer savings.

### 4. Preparation and Marketing of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review the underwriters' preparation and marketing of the proposed Recovery Bonds, including indicative pricing.[9] The Finance Team also had the right to review the marketing approach for the Recovery Bonds.[10]

---

[8] Decision, Ordering ¶ 3.

[9] Decision, Ordering ¶ 3.

[10] Decision, Ordering ¶ 3.

In meetings with PG&E, the Finance Team explored the risks and benefits of using an asset backed security (ABS) or corporate approach to marketing and structuring the Recovery Bonds. PG&E and its structuring advisor presented the proposed structure to the Finance Team and its proposal to market to both ABS and corporate investors. The Finance Team actively followed and commented on the evaluation of potential structures, including requesting the review of and evaluating alternative structures focusing on maximizing investor participation to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms.

After evaluation of a broad range of potential alternatives, PG&E ultimately selected, with the Finance Team's concurrence, a proposed alternative that was anticipated to produce the greatest amount of investor interest, highest present value savings and, lowest weighted average interest rate on the Recovery Bonds relative to traditional utility financing mechanisms. Having conducted its review and provided input and comments on the proposed structuring and marketing of the Recovery Bonds, the Finance Team approved the approach to register the Recovery Bonds with the Securities and Exchange Commission on a Form SF-1 to facilitate greater liquidity and identify the Recovery Bonds as not "asset-backed securities" as such term is defined by the SEC in governing regulations Item 1101 of Regulation AB.

With the opportunity to provide comment by the Finance Team, PG&E developed and implemented a marketing and structuring plan to incentivize underwriters to market the Recovery Bonds to their customers and to reach out to a broad base of potential investors, including both corporate and ABS investors and investors who have not previously purchased this type of security. PG&E informed investors early about securitization, through a non-deal road show and the underwriters agreed to use all forms of marketing available to them to distribute the offering, including educating their sales force and providing potential investors with access to individual, small group, and/or internet roadshows to conduct their due diligence on the investment.

Pursuant to the Decision, the Finance Team reviewed and provided input on certifications provided by PG&E and the lead underwriters, necessary to further align interests and ensure the statutory objective was achieved.

The Finance Team was apprised that PG&E held frequent market update discussions with the underwriting team to develop recommendations for pricing. PG&E and the Finance Team met with the underwriting team before and during the marketing phase. The Finance Team's Financial Advisor engaged with the underwriters on key elements of the marketing, pricing, and syndication process including participating in market updates, pricing discussions, and road show meetings, using such information to inform the Finance Team's review and feedback on the structure and marketing process. This process included participating in pricing discussions, review of subscriptions, and modifications available, focused on meeting the statutory objective.

### 5. Transaction Fees and Costs

Pursuant to the Decision, the Finance Team had the right to review all transaction fees and costs for the Recovery Bonds, including upfront financing costs and ongoing financing costs.[11] That review included reviewing each of the upfront and ongoing fees, such as an annual servicing fee to PG&E, third party servicing fees and administrative fees.[12]

The Finance Team asked questions and provided input on the fees and costs for the Recovery Bonds, including a review of pricing comparisons. The Finance Team provided feedback on various aspects of the fees and costs for the Recovery Bonds and required modifications to the structure to achieve incremental savings for the benefit of ratepayers. As determined in the Financing Order, the transaction also included a credit enhancement for the Recovery Bonds in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount of the Recovery Bonds. The rate of return on this amount, tied to the cost of the securitization, was also determined in the Financing Order, and reviewed by the Finance Team.

### 6. Collateral and Credit Enhancements

Pursuant to the Decision, the Finance Team was directed to determine whether over-collateralization and other additional credit enhancements would be required for the transaction.[13] In response to the Finance Team's inquiries and input, PG&E confirmed no additional enhancements would be required in order to obtain the highest possible credit rating and achieve the statutory objective.

### 7. Sale of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review and approve the sale of the Recovery Bonds in a negotiated offering through one or more underwriters.[14]

The Finance Team worked with PG&E and the underwriters (and each of their respective counsels) to finalize documentation in accordance with established standards for transactions of this sort and the terms of the Decision. The Finance Team was apprised of developments in the marketing process including the road show process and results, the level of interest from investors, questions raised throughout the process and pricing implications.

## V. CONCLUSION

The Finance Team has completed its pre-issuance review and approves the material terms of the Recovery Bonds in the Draft Issuance Advice Letter in accordance with the Decision (pending review of ultimately proposed final pricing levels). Based on the materials that the Finance Team has received and reviewed, the Finance Team is satisfied that the issuance of the Recovery Bonds as proposed would reduce, to the maximum extent possible, consumer

---

[11] Decision, Ordering ¶ 3.

[12] Decision, Ordering ¶ 3, Conclusion of Law ¶ 3.

[13] Decision, Ordering ¶ 3.

[14] Decision, Ordering ¶ 3.

rates on a present value basis as compared to the use of traditional utility financing mechanisms.

Arocles Aguilar

Arocles Aguilar
General Counsel
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Edward Randolph

Edward Randolph
Deputy Executive Director for
Energy and Climate Policy/
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

# EXHIBIT A

# Draft Issuance Advice Letter

Pacific Gas and Electric Company®

SidneyBobDietzII
Director
RegulatoryRelations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

Month XX, 2021

**Advice 3XXX-G/5XXX-E**
(Pacific Gas and Electric Company ID U 39 E/G/M)

Public Utilities Commission of the State of California

**Subject:** **Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission (CPUC) Decision (D.) 21-06-030 (the Financing Order), Pacific Gas and Electric Company (PG&E) hereby transmits for submission, within one day after the pricing date of this series of Wildfire Hardening Recovery Bonds, the initial Fixed Recovery Charges for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series 2021-A, Tranche(s) A-1, A-2 and A-3 (Recovery Bonds).

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto is the Finance Team's pre-issuance approval letter dated November , 2021.

## Purpose

This submission establishes initial Fixed Recovery Charges for rate schedules for Consumers. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner (Special Purpose Entity or SPE), including the Billing Commencement Date. Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Upfront Financing Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In the Financing Order, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the rate design methodology and Fixed Recovery Charge cash flow formula found reasonable by the Commission in the Financing Order to establish initial Fixed Recovery Charges for a series of Recovery Bonds. Using this methodology and formula approved by the Commission in the Financing Order, this submission establishes the initial Fixed Recovery Charges.

**Issuance Information**

The Financing Order requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2021-A
Recovery Property Owner (SPE): PG&E Recovery Funding LLC
Bond Trustee: The Bank of New York Mellon Trust Company, N.A.
Closing Date: __/__/2021
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued (Authorized Amount): $860,399,000.00 (See Table 1 below)

Upfront Financing Costs: $10,351,000.00 (See Table 2 below)
Upfront Financing Costs as a Percent of Principal Amount Issued: 1.2%
Coupon Rate(s): See Exhibit 1
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): See Exhibit 1
Legal Maturity Date(s): See Exhibit 1
Payment Dates (semi-annually): January 15 and July 15
Annual Servicing Fee as a percent of the issuance amount: 0.05%
Annual Administration Fee: $75,000
Overcollateralization amount for the series, if any: None

FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: December 1, 2021
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**Securitized Amount**

The following table sets for the computation of the final Securitized Amount (i.e., the principal amount of the Recovery Bonds).

| Table 1: Securitized Amount | |
|---|---|
| Initial AB 1054 CapEx Amount:<br>• 2020<br>• 2021 | $609,155,000<br>$240,893,000 |
| Upfront Financing Costs (See Table 2 below) | $10,351,000 |
| Total Securitized Amount | $860,399,000 |

PG&E has determined that the Community Wildfire Safety Program (CWSP) system hardening costs to be recovered through the issuance of Recovery Bonds described herein do not exceed 115 percent of the Commission-approved per-mile costs set forth in D.20-12-005 at page 119.

## Upfront Financing Costs

The following table includes actual or estimated (as noted) Upfront Financing Costs to be incurred in connection with the issuance of the Recovery Bonds:

| Table 2: Upfront Financing Costs | |
|---|---|
| Underwriters' Fees and Expenses | $3,441,596 |
| Legal Fees and Expenses | $3,523,734 |
| Rating Agency Fees | $989,459 |
| Accounting Fees and Expenses | $125,000 |
| Company's Advisory Fee | $255,000 |
| Servicer Set-up Costs | $3,000 |
| SEC Registration Fees | $94,135 |
| Section 1904 Fees | $436,200 |
| Printing / EDGARizing Expenses | $40,000 |
| Trustee / Trustee Counsel Fee and Expenses | $52,000 |
| Original Issue Discount | TBD upon pricing |
| Commission's Costs and Expenses | $1,219,500 |
| Miscellaneous | $171,376 |
| | |
| **Total** | **$10,351,000.00** |
| **Note 1:** Section 1904 Fees computed in accordance with Decision 21-06-030 | |

**True-Up Mechanism**

Changes to the Fixed Recovery Charges will be requested through the submission of Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters in accordance with the Financing Order. Annually before each FRC Annual Adjustment Date (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of Recovery Bonds), semi-annually, if required by the servicer, and more frequent as required by the servicer, the servicer will submit Routine True-Up Mechanism Advice Letters in the form of Attachment 3 to the Financing Order to ensure that Fixed Recovery Charges collections are sufficient to make all scheduled payments of bond principal, interest, and other Ongoing Financing Costs on a timely basis during each of the two payment periods and, in the case of semi-annual Routine True-Up Mechanism Advice Letter, to replenish any draws upon the capital subaccount. The first payment period means the period commencing on the Closing Date and ending (and including) the first Payment Date following the Closing Date (the "First Payment Period"); the second payment period means the period commencing on the day following the first Payment Date and ending (and including) the next Payment Date (the "Second Payment Period"). The servicer may also submit Non-Routine True-Up Mechanism Advice Letters in the form of Attachment 4 to the Financing Order.

**Ongoing Financing Costs**

The following table includes estimated Ongoing Financing Costs for the First and Second Payment periods following Closing Date to be recovered through Fixed Recovery Charges in accordance with the Financing Order.

**TABLE 3: Estimated Ongoing Financing Costs**

| | First Payment Period | Second Payment Period |
|---|---|---|
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $277,240 | $215,100 |
| Administration Fee | $48,333 | $37,500 |
| Accounting Fees and Expenses | $37,500 | $37,500 |
| Legal Fees and Expenses | $17,500 | $17,500 |
| Rating Agency Surveillance Fees | $20,000 | $20,000 |
| Trustee Fees and Expenses | $2,100 | $2,100 |
| Independent Director Fees | $1,500 | $1,500 |
| Printing / EDGARizing Expenses | $5,000 | $5,000 |
| Return on Equity | $69,818 | $54,169 |
| Miscellaneous Fees and Expenses | $5,000 | $5,000 |

| | | |
|---|---|---|
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$483,991** | **$395,369** |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of initial principal amount) | $3,326,876 | $2,581,197 |
| **TOTAL ONGOING FINANCING COSTS (Third Party as Servicer)** | **$3,533,627** | **$2,761,466** |

## Fixed Recovery Charges

Table 4 below shows the inputs and current assumptions for each of the variables used in calculating the Fixed Recovery Charges:

| TABLE 4: Input Values For Fixed Recovery Charges | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Allocation Factors for each Customer Class (see Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Projected kWh sales for each Customer Class for payment period (See Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Percent of Consumers' revenue written off | 0.301% | 0.301% |
| Average Days Sales Outstanding | 55 | 55 |
| Ongoing Financing Costs for the applicable payment period (See Table 3 above) | $483,991 | $395,369 |
| Recovery Bond Principal | $18,365,684.46 | $13,530,457.77 |
| Recovery Bond Interest | $14,872,335.22 | $10,691,580.86 |
| Periodic Payment Requirement (See Exhibit 2) | $33,722,010.68 | $24,609,164.14 |
| Periodic Billing Requirement (See Exhibit 3) | $33,722,010.68 | $24,609,164.14 |

Table 5 shows the initial Fixed Recovery Charges for each FRC Consumer Class:

| TABLE 5: Fixed Recovery Charges (cent per kWh) | |
|---|---|
| **FRC Consumer Class** | **WHC*** |
| **Bundled Service** | |
| Residential | 0.110 |
| Residential – CARE | - |
| Residential – Non-CARE | 0.147 |
| Small Commercial | 0.151 |
| Medium Commercial | 0.124 |
| Medium Commercial – A/B-10T | 0.084 |
| Medium Commercial – A/B-10P | 0.114 |
| Medium Commercial – A/B-10S | 0.125 |
| E/B-19 | 0.105 |
| E/B-19T | 0.083 |
| E/B-19P | 0.095 |
| E/B-19S | 0.106 |
| Streetlight | 0.128 |
| Standby | 0.086 |
| Standby – STOU T | 0.075 |
| Standby – STOU P | 0.300 |
| Standby – STOU S | 0.152 |
| Agriculture | 0.134 |
| E/B-20 | 0.077 |
| E/B-20 T | 0.057 |

This document contains CONFIDENTIAL information described in Declaration Supporting Confidential Designation dated [November [●]], 2021.

Confidential document solely for use in connection with the AB1054 securitization; Exempt from Public Disclosure Under GO 66-D Preliminary draft subject to material change. This is intended for discussion purposes only and is not intended for broader distribution beyond the original recipients.

| | |
|---|---|
| E/B-20 P | 0.088 |
| E/B-20 S | 0.097 |
| Average Bundled Rate | 0.110 |
| **Direct Access/Community Choice Aggregation (DA/CCA)** | |
| Residential | 0.110 |
| Residential – CARE | - |
| Residential – Non-CARE | 0.147 |
| Small Commercial | 0.151 |
| Medium Commercial | 0.124 |
| Medium Commercial – A/B-10T | 0.084 |
| Medium Commercial – A/B-10P | 0.114 |
| Medium Commercial – A/B-10S | 0.125 |
| E/B-19 | 0.105 |
| E/B-19T | 0.083 |
| E/B-19P | 0.095 |
| E/B-19S | 0.106 |
| Streetlight | 0.128 |
| Standby | 0.086 |
| Standby – STOU T | 0.075 |
| Standby – STOU P | 0.300 |
| Standby – STOU S | 0.152 |
| Agriculture | 0.134 |
| E/B-20 | 0.077 |
| E/B-20 T | 0.057 |
| E/B-20 P | 0.088 |
| E/B-20 S | 0.097 |
| Average DA/CCA Rate | 0.110 |

*The balances in the Wildfire Hardening Fixed Recovery Charge Balancing Account (WHFRCBA) will be credited or recovered in rates in the same manner as other distribution charges, and will not be collected on a volumetric basis (cents per kWh) on some rate schedules. WHFRCBA balances will be credited or recovered from DL Consumers (as defined in the Financing Order) through the rates set forth in Electric Preliminary Statement Part JG, WHFRCBA.

## Recovery Property

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charges set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charges set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 2, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charges, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charges under the True-Up Mechanism.

These Fixed Recovery Charges, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 2 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Proposed Tariff Changes**

PG&E will submit all tariff sheets reflecting the revised Fixed Recovery Charges shown in Table 5 in the consolidated revenue requirement and rate change advice letter for rates effective in [date].

**Description of Exhibits**

Exhibit 1 presents the debt service schedule for the Recovery Bonds, including expected principal amortization, scheduled final payment dates and legal maturity dates, interest rates, and aggregate scheduled debt service per payment date.

Exhibit 2 presents the Periodic Payment Requirements related to the Recovery Bonds for the two payment periods following the Closing Date.

Exhibit 3 presents the Fixed Recovery Charges calculations.

**Effective Date**

In accordance with the Financing Order, unless before noon on the fourth business day after pricing the Commission Staff rejects this Issuance Advice Letter for failure to adhere to the terms of the Financing Order, the Issuance Advice Letter and the Fixed Recovery Charges established by this Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charges will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes. Further all Upfront Financing Costs and all Ongoing Financing Costs for the life of the Recovery Bonds shall be recoverable as provided in the Financing Order.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list **and the parties on the service list for A.21-02-020**. Address changes should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: https://www.pge.com/tariffs/advice-letters.page.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

Attachments

cc: Service List A.21-02-020

**PG&E Gas and Electric**
**Advice Submittal List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison
Schneider & Harris LLP Energy
Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
IGS Energy
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated
Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead
Electric Company
Western Manufactured Housing
Communities Association (WMA)
Yep Energy

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

November 21, 2022

**Advice 6769-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject:** **Issuance Advice Letter Submission for Wildfire Hardening Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 22-08-004 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Wildfire Hardening Recovery Bonds, the initial Fixed Recovery Charges for the series. This Issuance Advice Letter is for the Wildfire Hardening Senior Secured Recovery Bonds Series 2022-A, Tranche(s) A-1, A-2, and A-3 ("Wildfire Hardening Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 4 is the Finance Team's pre-issuance approval letter dated November 18, 2022.

## Purpose

This submission establishes initial Fixed Recovery Charges for rate schedules for Consumers. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"), including the Billing Commencement Date. Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Upfront Financing Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In D. 22-08-004, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Wildfire Hardening Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the rate design methodology and Fixed Recovery Charge cash flow formula (the "adjustment mechanism") found reasonable by the Commission in D. 22-08-004 to establish initial Fixed Recovery Charges for a series of Wildfire Hardening Recovery Bonds. Using this methodology and formula approved by the Commission in D. 22-08-004, this submission establishes the initial Fixed Recovery Charges.

**Issuance Information:**

Decision 22-08-004 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2022-A
Recovery Property Owner (SPE): PG&E Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: November 30, 2022
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued (Authorized Amount): $983,362,000
Upfront Financing Costs: $8,362,000
Upfront Financing Costs as a Percent of Principal Amount Issued: 0.85%
Coupon Rate(s): See Exhibit 1
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): See Exhibit 1
Legal Maturity Date(s): See Exhibit 1
Payment Dates (semi-annually): January 15 and July 15
Annual Servicing Fee as a percent of the issuance amount: .05%
Overcollateralization amount for the series, if any: None
FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: January 1, 2023
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following first Payment Date through and including second Payment Date

**Securitized Amount:**

The following table sets forth the computation of the final Authorized Amount (i.e., the principal amount of the Recovery Bonds).

| Table 1: Authorized Amount | |
|---|---|
| Second AB 1054 CapEx Amount: Approved in D.20-12-005 | $975,000,000 |
| Upfront Financing Costs (See Table 2 below) | $8,362,000 |
| Total Securitized Amount | $983,362,000 |

The amounts set forth in Table 1 are within the amounts approved as recovery costs in D. 22-08-004. PG&E has determined that Community Wildfire Safety Program (CWSP) system hardening costs approved in D.20-12-005 and to be recovered through issuance of the Wildfire Hardening Recovery Bonds described herein do not exceed 115 percent of the Commission-approved per-mile costs set forth in D.20-12-005 at page 119.

**Upfront Financing Costs:**

The following table includes actual or estimated (as noted) Upfront Financing Costs to be incurred in connection with the issuance of the Wildfire Hardening Recovery Bonds:

| **Table 2<br>Upfront Financing Costs** | |
|---|---|
| Underwriters' Fees and Expenses | $3,933,448 |
| Legal Fees and Expenses | 1,245,000 |
| Rating Agency Fees | 1,130,866 |
| Accounting Fees and Expenses | 125,000 |
| PG&E's Advisory Fee | 255,000 |
| Servicer Set-up Costs | 0 |
| SEC Registration Fees | 108,349 |
| Section 1904 Fees | 497,681 |
| Printing / EDGARizing Expenses | 150,000 |
| Trustee / Trustee Counsel Fee and Expenses | 41,500 |
| Original Issue Discount | 69,391 |
| Commission's Costs and Expenses | 745,000 |
| Miscellaneous | 60,765 |
| | |
| **Total** | **$8,362,000** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 22-08-004. | |

**True-Up Mechanism:**

Changes to the Fixed Recovery Charges will be requested through the submission of Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters in accordance with Decision 22-08-004. Annually before each FRC Annual Adjustment Date (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Wildfire Hardening Recovery Bonds), and if determined necessary by the servicer, semi-annually and more frequently, the servicer will submit Routine True-Up Mechanism Advice Letters in the form of Attachment 3 to the Financing Order to ensure that Fixed Recovery Charges collections be sufficient to make all scheduled payments of bond principal, interest, and other Ongoing Financing Costs on a timely basis during each of the two payment periods and, in the case of semi-annual Routine True-Up Mechanism Advice Letter, to replenish any draws upon the capital subaccount. The first payment period means the period commencing on the Closing Date and ending (and including) the first Payment Date following the Closing Date (the "First Payment Period"); the second payment period means the period commencing on the day following the first Payment Date following the adjustment date and ending on (and including) the next Payment Date (the "Second Payment Period"). The servicer may also submit Non-Routine True-Up Mechanism Advice Letters in the form of Attachment 4 to the Financing Order.

**Ongoing Financing Costs:**

The following table includes estimated Ongoing Financing Costs for the First and Second Payment periods following Closing Date to be recovered through Fixed Recovery Charges in accordance with the Financing Order.

| **Table 3: Estimated Ongoing Financing Costs** | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Servicing Fee (PG&E as Servicer) (0.05% of the initial principal amount of the Wildfire Hardening Recovery Bonds) | $307,301 | $245,841 |
| Administration Fee | 46,875 | 37,500 |
| Accounting Fees and Expenses | 31,250 | 31,250 |
| Legal Fees and Expenses | 17,500 | 17,500 |
| Rating Agency Surveillance Fees | 20,000 | 20,000 |
| Trustee Fees and Expenses | 7,725 | 7,725 |
| Independent Director Fees | 750 | 750 |
| Printing / EDGARizing Expenses | 5,000 | 5,000 |
| Return on Equity | 167,595 | 134,076 |
| Miscellaneous Fees and Expenses | 5,000 | 5,000 |
| | | |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$608,996** | **$504,642** |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of initial principal amount) | $3,687,608 | $2,950,086 |
| **TOTAL ONGOING FINANCING COSTS (Third Party as Servicer)** | **$3,989,303** | **$3,208,887** |

**Fixed Recovery Charges:**

Table 4 below shows the inputs and current assumptions for each of the variables used in calculating the Fixed Recovery Charges.

| Table 4: Input Values For Fixed Recovery Charges | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Allocation Factors for each Customer Class (see Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Projected kWh sales for each Customer Class for payment period (See Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Percent of Consumers' revenue written off | 0.34% | 0.34% |
| Average Days Sales Outstanding | 55 | 55 |
| Ongoing Financing Costs for the applicable payment period (See Table 3 above) | $608,996 | $504,642 |
| Wildfire Hardening Recovery Bond Principal | $11,195,480 | $9,276,743 |
| Wildfire Hardening Recovery Bond Interest | $33,014,783 | $26,129,421 |
| Periodic Payment Requirement (See Exhibit 2) | $44,819,260 | $35,910,806 |
| Periodic Billing Requirement (See Exhibit 3) | $44,819,260 | $35,910,806 |

Table 5 shows the initial Fixed Recovery Charges for each FRC Consumer Class. The Fixed Recovery Charge calculations are shown in Exhibit 3.

| Table 5: Fixed Recovery Charges (cent per kWh) | |
|---|---|
| **FRC Consumer Class** | **WHC*** |
| Residential | 0.148 |
| Residential – CARE | - |
| Residential – Non-CARE | 0.215 |
| Small Commercial | 0.219 |
| Medium Commercial | 0.182 |
| Medium Commercial – A/B-10T | 0.126 |
| Medium Commercial – A/B-10P | 0.172 |
| Medium Commercial – A/B-10S | 0.183 |
| E/B-19 | 0.154 |
| E/B-19T | 0.121 |
| E/B-19P | 0.147 |
| E/B-19S | 0.155 |
| Streetlight | 0.184 |
| Standby | 0.124 |
| Standby – STOU T | 0.113 |
| Standby – STOU P | 0.375 |
| Standby – STOU S | 0.225 |
| Agriculture | 0.197 |

| | |
|---|---|
| E/B-20 | 0.112 |
| E/B-20 T | 0.087 |
| E/B-20 P | 0.129 |
| E/B-20 S | 0.134 |
| Average Bundled Rate | 0.157 |
| **Direct Access/Community Choice Aggregation (DA/CCA)** | |
| Residential | 0.148 |
| Residential – CARE | - |
| Residential – Non-CARE | 0.215 |
| Small Commercial | 0.219 |
| Medium Commercial | 0.182 |
| Medium Commercial – A/B-10T | 0.126 |
| Medium Commercial – A/B-10P | 0.172 |
| Medium Commercial – A/B-10S | 0.183 |
| E/B-19 | 0.154 |
| E/B-19T | 0.121 |
| E/B-19P | 0.147 |
| E/B-19S | 0.155 |
| Streetlight | 0.184 |
| Standby | 0.124 |
| Standby – STOU T | 0.113 |
| Standby – STOU P | 0.375 |
| Standby – STOU S | 0.225 |
| Agriculture | 0.197 |
| E/B-20 | 0.112 |
| E/B-20 T | 0.087 |
| E/B-20 P | 0.129 |
| E/B-20 S | 0.134 |
| Average DA/CCA Rate | 0.157 |

*Class average rates are calculated by dividing total revenues expected to be collected by the WHC by total forecasted system sales for the class for the rate effective period.

**Recovery Property:**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charges set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charges set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 2, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charges, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charges under the True-Up Mechanism.

These Fixed Recovery Charges, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 2 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Proposed Tariff Changes:**

PG&E will submit all tariff sheets reflecting the revised Fixed Recovery Charges shown in Table 5 in the consolidated revenue requirement and rate change advice letter for rates effective on January 1, 2023.

**Effective Date**

In accordance with Decision 22-08-004, unless before noon on the fourth business day after pricing the Commission staff rejects this Issuance Advice Letter for failure to adhere to the terms of the Financing Order, the Issuance Advice Letter and the Fixed Recovery Charges established by this Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charges will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes. Further all Upfront Financing Costs and all Ongoing Financing Costs for the life of the Wildfire Hardening Recovery Bonds shall be recoverable as provided in the Financing Order.

**Description of Exhibits:**

Exhibit 1 presents the debt service schedule for the Wildfire Hardening Recovery Bonds, including expected principal amortization, scheduled final payment dates and final legal maturity dates, interest rates, and aggregate scheduled debt service per payment date.

Exhibit 2 presents the Periodic Payment Requirements related to the Wildfire Hardening Recovery Bonds for the two payment periods following the Closing Date.

Exhibit 3 presents the Fixed Recovery Charges calculations.

Exhibit 4 provides the pre-issuance approval letter of the Finance Team.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.22-03-010. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

**Attachments**

Attachment 1: Exhibits 1-4

Exhibit 1: Recovery Bond Terms and Debt Service Schedule

Exhibit 2: Periodic Payment Requirements

Exhibit 3: Fixed Recovery Charges Calculations

Exhibit 4: Pre-Issuance Approval Letter of the Finance Team

cc: Service List for A.22-03-010

California Public Utilities Commission

# ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6769-E

Tier Designation: 1

Subject of AL: Issuance Advice Letter Submission for Wildfire Hardening Recovery Bonds

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.22-08-004

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are **to be sent via email and are** due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

| | |
|---|---|
| California Public Utilities Commission<br>Energy Division Tariff Unit Email:<br>EDTariffUnit@cpuc.ca.gov | Contact Name: Sidney Bob Dietz II, c/o Megan Lawson<br>Title: Director, Regulatory Relations<br>Utility/Entity Name: Pacific Gas and Electric Company<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: PGETariffs@pge.com |
| | Contact Name:<br>Title:<br>Utility/Entity Name:<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: |

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Advice 6769-E
November 21, 2022

# Attachment 1

## Exhibits 1-4

# EXHIBIT 1

**Exhibit 1**
**Recovery Bond Terms and Debt Service Schedule**

| Tranche | Expected Weighted Average Life | Principal Amount Offered | Scheduled Final Payment Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|---|
| A-1 | 5.29 | $214,922,000 | 7/15/2032 | 7/15/2034 | 5.045% |
| A-2 | 12.49 | $200,000,000 | 1/15/2038 | 1/15/2040 | 5.256% |
| A-3 | 20.52 | $568,440,000 | 7/15/2047 | 7/15/2049 | 5.536% |
| | | $983,362,000 | | | |

**Tranche A-1**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/30/2022 | $214,922,000 | | | |
| 7/15/2023 | $203,726,520 | $11,195,480 | $6,776,759 | $17,972,240 |
| 1/15/2024 | $194,449,777 | $9,276,743 | $5,139,001 | $14,415,744 |
| 7/15/2024 | $184,907,580 | $9,542,197 | $4,904,996 | $14,447,193 |
| 1/15/2025 | $175,092,333 | $9,815,247 | $4,664,294 | $14,479,541 |
| 7/15/2025 | $164,996,222 | $10,096,110 | $4,416,704 | $14,512,814 |
| 1/15/2026 | $154,611,212 | $10,385,010 | $4,162,030 | $14,547,040 |
| 7/15/2026 | $143,929,034 | $10,682,178 | $3,900,068 | $14,582,245 |
| 1/15/2027 | $132,941,186 | $10,987,848 | $3,630,610 | $14,618,458 |
| 7/15/2027 | $121,638,921 | $11,302,265 | $3,353,441 | $14,655,707 |
| 1/15/2028 | $110,013,241 | $11,625,680 | $3,068,342 | $14,694,021 |
| 7/15/2028 | $98,054,893 | $11,958,348 | $2,775,084 | $14,733,432 |
| 1/15/2029 | $85,754,356 | $12,300,537 | $2,473,435 | $14,773,971 |
| 7/15/2029 | $73,101,840 | $12,652,516 | $2,163,154 | $14,815,670 |
| 1/15/2030 | $60,087,272 | $13,014,568 | $1,843,994 | $14,858,562 |
| 7/15/2030 | $46,700,292 | $13,386,980 | $1,515,701 | $14,902,681 |
| 1/15/2031 | $32,930,243 | $13,770,049 | $1,178,015 | $14,948,063 |
| 7/15/2031 | $18,766,165 | $14,164,078 | $830,665 | $14,994,744 |
| 1/15/2032 | $4,196,781 | $14,569,384 | $473,377 | $15,042,760 |
| 7/15/2032 | $0 | $4,196,781 | $105,864 | $4,302,645 |

**Exhibit 1**
**Tranche A-2**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/30/2022 | $200,000,000 | | | |
| 7/15/2023 | $200,000,000 | $0 | $6,570,000 | $6,570,000 |
| 1/15/2024 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2024 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2025 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2025 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2026 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2026 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2027 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2027 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2028 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2028 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2029 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2029 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2030 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2030 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2031 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2031 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 1/15/2032 | $200,000,000 | $0 | $5,256,000 | $5,256,000 |
| 7/15/2032 | $189,210,495 | $10,789,505 | $5,256,000 | $16,045,505 |
| 1/15/2033 | $173,769,697 | $15,440,798 | $4,972,452 | $20,413,250 |
| 7/15/2033 | $157,850,311 | $15,919,386 | $4,566,668 | $20,486,053 |
| 1/15/2034 | $141,437,504 | $16,412,807 | $4,148,306 | $20,561,113 |
| 7/15/2034 | $124,515,982 | $16,921,522 | $3,716,978 | $20,638,500 |
| 1/15/2035 | $107,069,978 | $17,446,004 | $3,272,280 | $20,718,284 |
| 7/15/2035 | $89,083,234 | $17,986,743 | $2,813,799 | $20,800,542 |
| 1/15/2036 | $70,538,992 | $18,544,242 | $2,341,107 | $20,885,350 |
| 7/15/2036 | $51,419,971 | $19,119,021 | $1,853,765 | $20,972,786 |
| 1/15/2037 | $31,708,355 | $19,711,615 | $1,351,317 | $21,062,932 |
| 7/15/2037 | $11,385,778 | $20,322,577 | $833,296 | $21,155,872 |
| 1/15/2038 | $0 | $11,385,778 | $299,218 | $11,684,997 |

**Exhibit 1**
**Tranche A-3**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 11/30/2022 | $568,440,000 | | | |
| 7/15/2023 | $568,440,000 | $0 | $19,668,024 | $19,668,024 |
| 1/15/2024 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2024 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2025 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2025 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2026 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2026 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2027 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2027 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2028 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2028 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2029 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2029 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2030 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2030 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2031 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2031 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2032 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2032 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2033 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2033 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2034 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2034 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2035 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2035 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2036 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2036 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2037 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 7/15/2037 | $568,440,000 | $0 | $15,734,419 | $15,734,419 |
| 1/15/2038 | $558,873,303 | $9,566,697 | $15,734,419 | $25,301,116 |
| 7/15/2038 | $537,252,368 | $21,620,935 | $15,469,613 | $37,090,548 |
| 1/15/2039 | $514,918,267 | $22,334,101 | $14,871,146 | $37,205,247 |
| 7/15/2039 | $491,847,475 | $23,070,792 | $14,252,938 | $37,323,729 |
| 1/15/2040 | $468,015,694 | $23,831,782 | $13,614,338 | $37,446,120 |
| 7/15/2040 | $443,397,820 | $24,617,873 | $12,954,674 | $37,572,547 |
| 1/15/2041 | $417,967,927 | $25,429,894 | $12,273,252 | $37,703,145 |
| 7/15/2041 | $391,699,228 | $26,268,699 | $11,569,352 | $37,838,051 |
| 1/15/2042 | $364,564,056 | $27,135,172 | $10,842,235 | $37,977,406 |
| 7/15/2042 | $336,533,831 | $28,030,225 | $10,091,133 | $38,121,358 |
| 1/15/2043 | $307,579,029 | $28,954,802 | $9,315,256 | $38,270,059 |
| 7/15/2043 | $277,669,152 | $29,909,876 | $8,513,788 | $38,423,664 |
| 1/15/2044 | $246,772,698 | $30,896,454 | $7,685,882 | $38,582,336 |
| 7/15/2044 | $214,857,125 | $31,915,573 | $6,830,668 | $38,746,242 |
| 1/15/2045 | $181,888,817 | $32,968,308 | $5,947,245 | $38,915,554 |
| 7/15/2045 | $147,833,049 | $34,055,768 | $5,034,682 | $39,090,451 |
| 1/15/2046 | $112,653,951 | $35,179,098 | $4,092,019 | $39,271,116 |
| 7/15/2046 | $76,314,471 | $36,339,480 | $3,118,261 | $39,457,742 |
| 1/15/2047 | $38,776,333 | $37,538,138 | $2,112,385 | $39,650,522 |
| 7/15/2047 | $0 | $38,776,333 | $1,073,329 | $39,849,662 |

# EXHIBIT 2

**Exhibit 2**
**Periodic Payment Requirements**

The total amount payable to the owner of the Recovery Property, or its assignee(s), pursuant to this issuance advice letter is a $983,362,000 principal amount, plus interest on such principal amount, plus Ongoing Financing Costs, to be obtained from Fixed Recovery Charges calculated in accordance with the Decision.

The Fixed Recovery Charges shall be adjusted from time to time, at least annually, via the Routine True-Up Mechanism Advice Letter and Non-Routine True-Up Mechanism Advice Letter in accordance with the Decision.

The following amounts are scheduled to be paid by the Bond Trustee from Fixed Recovery Charges it has received during the two Payment Periods following the Closing Date. These payment amounts include principal plus interest and plus other Ongoing Financing Costs.

| Payment Period | Recovery Bond Payments (See Exhibit 1) | Ongoing Financing Costs (see Table 3) | Periodic Payment Requirement |
|---|---|---|---|
| **First Payment Period** | $44,210,264 | $608,996.10 | $44,819,260 |
| **Second Payment Period** | $35,406,164 | $504,641.88 | $35,910,806 |

# EXHIBIT 3

**Exhibit 3**
**Fixed Recovery Charges Calculations**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) = (F) x (B) / (C) |
|---|---|---|---|---|---|---|
| FRC Consumer Class | WHFRC Allocation Factors for Effective Period[1] | WHFRC Sales Factors for Effective Period[1] | Highest Periodic Billing Requirement ($) | Forecasted Billed and Collected Sales for Highest Periodic Requirement (MWh) | System Average WHFRC (¢/kWh) | New WHFRC (¢/kWh) |
| Residential - CARE [2] | 0.0% | 0.0% | 44,819,260 | 0 | 0.176 | - |
| Residential - Non-CARE | 33.4% | 27.4% | 44,819,260 | 6,858,770 | 0.176 | 0.215 |
| Small Commercial | 14.3% | 11.5% | 44,819,260 | 3,007,974 | 0.176 | 0.219 |
| A/B-10T | 0.004% | 0.005% | 44,819,260 | 1,654 | 0.176 | 0.126 |
| A/B-10P | 0.1% | 0.1% | 44,819,260 | 31,909 | 0.176 | 0.172 |
| A/B-10S | 11.4% | 11.0% | 44,819,260 | 2,855,608 | 0.176 | 0.183 |
| E/B-19T | 0.05% | 0.07% | 44,819,260 | 18,270 | 0.176 | 0.121 |
| E/B-19P | 1.5% | 1.8% | 44,819,260 | 487,498 | 0.176 | 0.147 |
| E/B-19S | 16.1% | 18.4% | 44,819,260 | 4,815,114 | 0.176 | 0.155 |
| Streetlight | 0.3% | 0.3% | 44,819,260 | 89,785 | 0.176 | 0.184 |
| Standby - STOU T | 0.4% | 0.6% | 44,819,260 | 168,432 | 0.176 | 0.113 |
| Standby - STOU P | 0.0% | 0.02% | 44,819,260 | 6,954 | 0.176 | 0.375 |
| Standby - STOU S | 0.02% | 0.02% | 44,819,260 | 4,124 | 0.176 | 0.225 |
| Agriculture | 9.6% | 8.6% | 44,819,260 | 1,939,643 | 0.176 | 0.197 |
| E/B-20T | 4.2% | 8.5% | 44,819,260 | 2,256,747 | 0.176 | 0.087 |
| E/B-20P | 6.5% | 8.9% | 44,819,260 | 2,345,150 | 0.176 | 0.129 |
| E/B-20S | 2.0% | 2.7% | 44,819,260 | 720,922 | 0.176 | 0.134 |

(1) Effective Period is 1/1/2023 through 2/29/2024 and is defined as the time period in which these Wildfire Hardening Fixed Recovery Charges will be collected in rates.

(2) CARE customers are exempt from paying the fixed recovery charge.

# EXHIBIT 4

STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 18, 2022 **VIA ELECTRONIC MAIL**

Margaret K. Becker
Vice President and Treasurer
Pacific Gas and Electric Company
Mail Code B12H
77 Beale Street
San Francisco, CA 94105
Mari.Becker@pge.com

**Subject: Pre-Issuance Approval Letter for PG&E Senior Secured Recovery Bonds Series 2022-A, Tranches A-1 through A-3 (Recovery Bonds)**

Dear Ms. Becker,

Pursuant to Ordering Paragraph 4 of California Public Utilities Commission (the "Commission") Decision (D.) 22-08-004 (the "Decision"), the Commission Finance Team (consisting of Leuwam Tesfai, Deputy Executive Director for Energy and Climate Policy and Christine Jun Hammond, General Counsel, and their designated representatives) provides this letter evidencing the Finance Team's pre-issuance review and approval of Pacific Gas and Electric Company's ("PG&E") issuance of Recovery Bonds authorized by the Decision, the terms of which are set forth in the Draft Issuance Advice Letter for the Senior Secured Recovery Bonds Series 2022-A, Tranches A-1 through A-3 attached hereto as Exhibit A (the "Draft Issuance Advice Letter"). As set forth below, the Finance Team confirms it has completed its pre-issuance review of and approves the material terms of the Recovery Bonds as presented in the Draft Issuance Advice Letter.

In accordance with the Decision, the final terms and structure of the Recovery Bonds, including the recovery of the Upfront Financing Costs and all ongoing financing costs for the life of the Recovery Bonds, as well as the initial fixed recovery charges, are to be approved through the Issuance Advice Letter process as provided in the Decision.

## FINANCE TEAM REVIEW AND APPROVAL

### I. COMMISSION AUTHORITY FOR APPROVING STRUCTURE AND TERMS FOR RECOVERY BONDS

On March 11, 2022, PG&E filed an application under California Public Utilities Code Section 850 et seq.[1] seeking the Commission's approval of a proposed financing order for PG&E's second issuance of Recovery Bonds to finance fire risk mitigation capital expenditures and related costs and expenses. Specifically, PG&E requested authority to issue Recovery Bonds for $1.4 Billion,[2] including Financing Costs associated with issuing the Recovery Bonds.

The Commission reviewed PG&E's request, considered comments filed by stakeholders who were parties to the proceeding (A.22-03-010), issued a financing order, and granted PG&E's request to allow PG&E to submit an Issuance Advice Letter when final terms and structure for the Recovery Bonds have been established.[3] The Issuance Advice Letter is to include the critical details and final terms of the proposed Recovery Bonds and sets forth the cost allocation and rate design methodology and Fixed Recovery Charge cash flow formula authorized by the Commission to establish initial Fixed Recovery Charges for a series of Recovery Bonds.

On November 12, 2021, PG&E sponsored, and the issuing entity, PG&E Recovery Funding LLC, issued, an $860,399,000 aggregate principal amount of three tranches of Senior Secured Recovery Bonds, Series 2021-A.

### II. ESTABLISHMENT OF A FINANCE TEAM

The Decision provides for, among other tools, "employing the review and approval of the Finance Team … [to] reduce, to the maximum extent possible, the rates to Consumers on a present value basis."[4] which is consistent with the statutory mandate that "[t]he recovery of recovery costs through the designation of the fixed recovery charges and any associated fixed recovery tax amounts, and the issuance of recovery bonds in connection with the fixed recovery charges, would reduce, to the maximum extent possible, the rates

---

[1] On July 12, 2019, Governor Newsom signed into law Assembly Bill (AB) No. 1054, which amended Division 1, Part 1, Chapter 4, Article 5.8, commencing with § 850 of the Public Utilities Code. Public Utilities Code Article 5.8 was later amended by AB 1513 and AB 913 and authorizes the issuance of Recovery Bonds.

[2] On May 4, 2022, PG&E filed a statement containing a revised Application to exclude consideration of cost elements related to PG&E's Application in A.20-09-019, as these cost elements would not be finalized by the time of a decision in A.22-03-010.

[3] Decision Ordering ¶ 14.

[4] Decision Finding of Fact ¶ 3.

on a present value basis that consumers within the electrical corporation's service territory would pay as compared to the use of traditional utility financing mechanisms, which shall be calculated using the electrical corporation's corporate debt and equity in the ratio approved by the Commission at the time of the financing order."[5] We refer to this statutory mandate as the "Savings Standard".

Ordering Paragraphs 2 and 4 of the Decision provide that:

> The purpose of the Finance Team is to provide oversight over the structuring, marketing, and pricing of each Recovery Bond transaction and to review and approve the material terms of such transaction in light of the goal to reduce rates on a present value basis to the maximum extent possible pursuant to Assembly Bill 1054's directives.
>
> The Finance Team's pre-issuance review and approval of the material terms and structure of a series of Recovery Bonds shall be evidenced by an approval letter from the Finance Team to Pacific Gas and Electric Company (PG&E) delivered on or before the date of the pricing of the relevant Recovery Bonds. PG&E shall be required to include such an approval letter as an attachment to the Issuance Advice Letter relating to such series of Recovery Bonds, or as a supplement to such Issuance Advice Letter. Such approval letter from the Finance Team to PG&E shall be a condition precedent to the issuance of such series of Recovery Bonds.

Consistent with the Decision, the Commission established a Finance Team consisting of the Commission's Deputy Executive Director for Energy and Climate Policy, Leuwam Tesfai, the Commission's General Counsel, Christine Jun Hammond, and additional designated representatives from Commission staff. The Finance Team was advised by Ducera Partners LLC, as Financial Advisor, and Paul, Weiss, Rifkind, Wharton & Garrison LLP, as Legal Advisor.

## III. PG&E's ACTIVITIES

In accordance with the Financing Order, PG&E undertook a number of activities in arranging for the issuance of the Recovery Bonds. In addition to the specific activities discussed in the following section, PG&E has represented that it has undertaken the following activities:

[5] Public Utilities Code § 850.1(a)(1)(A)(ii)(III).

- Responded to all Finance Team inquiries and comments and incorporated Finance Team input.
- Registered the Recovery Bonds with the Securities and Exchange Commission (SEC) to facilitate greater liquidity and marketed the Recovery Bonds to ABS and corporate bond investors.
- Solicited advice from the underwriters on the number of rating agencies to apply with, selected two agencies with the benefit of such advice, and applied for and received preliminary Aaa(sf)/AAA(sf) ratings from two of the major rating agencies with final Aaa(sf)/AAA(sf) ratings as a condition of closing.
- Evaluated market conditions in consultation with the underwriters, including treasury market volatility and spread expansion, if any timing modifications would be appropriate, appropriate responses to Bloomberg's decision of corporate bond index eligibility for utility securitization bonds and current issuer specific considerations and determined when to go to market to achieve the Savings Standard.
- In conjunction with the underwriters' advice, developed and implemented a marketing approach, including considering time required, strategies to use, tools to rely on, and competing issuances, consistent with the Financing Order and Savings Standard.
- Provided preliminary prospectus to prospective investors.
- Pursued and received a green bond designation for the Recovery Bonds to expand the pool of potential investors.
- Allowed sufficient time for investors to review the preliminary prospectus and to ask questions regarding the transaction.
- Arranged for the issuance of rating agency pre-sale reports during the marketing period.
- During the period that the Recovery Bonds were marketed, PG&E held frequent market update discussions with the underwriting team and the Finance Team's financial advisors to review relevant pricing benchmarks, discuss market conditions and develop strategies for pricing.
- Had multiple conversations with members of the underwriting team and the Finance Team's financial advisors before and

during the marketing phase in which PG&E identified the existence of the Savings Standard.

- Conducted roadshow meetings with investors to provide information on the offering.
- Directed the underwriters to provide potential investors with access to an internet roadshow for viewing at investors' convenience.
- Adapted the Recovery Bond offering to market conditions and investor demand at the time of pricing. Variables impacting the final structure of the transaction were evaluated including the tranche structure, term, length of weighted average lives, issuance size, amortization schedules, credit protections and maturity of the Recovery Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order.
- Independently reviewed opportunities to achieve the best pricing, consistent with the Savings Standard, at the time of issuance taking into account the marketing process to date, level of subscription, market benchmarks, passive underwriter feedback, and advice of underwriters on steps necessary to achieve the best pricing.
- With consideration to input from, and the approval of, the Finance Team and underwriters (and each of their respective counsels), finalized documentation in accordance with established standards for transactions of this sort and the terms of the Financing Order.
- At the request of the Finance Team, and in light of current and future interest rate levels and volatility, evaluated floating interest rate structures and early redemption call features.

## IV. FINANCE TEAM REVIEW

The Finance Team met periodically with PG&E representatives, via teleconference, from September 2022 through November 2022, to address subjects such as: (1) the underwriter and syndication group size, selection process, participants, diverse bank inclusion, allocations, and economics, which involved a Request for Proposal (RFP) process, obtaining a broad view of transaction structure alternatives from potential underwriters and proposals from a broad set of banks; (2) the structure of the Recovery Bonds, including considerations reviewed or proposed during the RFP process and recommendations from PG&E and its lead underwriter, including on parameters to drive the greatest level of investor interest and resulting savings to ratepayers; (3) the Recovery Bonds' credit rating agency materials, supporting materials and preliminary AAA/Aaa results; (4) the underwriters' preparation, proposed marketing, marketing materials, and proposed syndication of the Recovery Bonds; (5) the proposed pricing approach of the Recovery Bonds and certifications to be provided by PG&E and the lead underwriters (with ongoing review and involvement in the pricing process); (6) all associated Recovery Bond costs (including Upfront Financing Costs and other Financing Costs), servicing and administrative fees and associated crediting as well as a comparison of such costs relative to other issuances, (7) maturities, weighted average lives and alternative structures, (8) reporting templates, (9) the amount of PG&E's equity contribution to the related Special Purpose Entity, (10) overcollateralization and other credit enhancements and (11) the initial calculation of the related Fixed Recovery Charges. The Finance Team also met both with PG&E and without PG&E to evaluate PG&E's proposals and to conduct due diligence, including reviewing the validity of PG&E's assumptions, evaluating potential modifications, and developing recommended paths forward. In accordance with the Decision, the Finance Team's review included the following:

### 1. Recovery Bonds Structure

Pursuant to the Decision, the Finance Team was provided the right to review all material terms of the Recovery Bonds and other items the Finance Team determined were appropriate to perform its reviewing role.[6] With the benefit of preliminary structures proposed by potential underwriters in the RFP process, the Finance Team considered and made inquiries about PG&E's proposed structure, proposed structuring parameters and proposed alternatives. The Finance Team discussed parameters to maximize potential net present value savings and available transaction alternatives and provided comments and input, which were evaluated and incorporated into the Recovery Bond structure. After conducting its review, the Finance Team accepted the proposed transaction structure, including three tranches of Recovery Bonds and structural elements designed to appeal to the broadest range of investors possible. The proposed transaction was found to be appropriate subject to modification, if required, as part of the marketing process, to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the rates that would be paid using traditional utility financing mechanisms.

[6] Decision, Ordering ¶ 3.

**2. Recovery Bonds Lead Advisor and Underwriters**

Pursuant to the Decision, the Finance Team was provided the right to oversee the process of selecting underwriters for the Recovery Bonds.[7] Accordingly, the Finance Team engaged in several meetings with PG&E to inquire about PG&E's request for proposals, the content of such requests for proposals which could be informative to the broader process, the responses provided, and the selection criteria for underwriters.

The underwriter group was expanded to include four diverse bank co-managers to supplement the underwriter group's experience and to include experience with transactions marketed to both ABS and corporate investors. PG&E named the lead left underwriter as the Diversity, Equity and Inclusion Coordinator and tasked it with a coordinating role among the co-managers. PG&E also requested that the lead left underwriter solicit feedback from the co-managers on best practices to facilitate and coordinate efforts such as to maximize their opportunity to participate in the bond issuance transaction.

The Finance Team assessed all materials provided to the Finance Team as part of PG&E's underwriter RFP processes, which included underwriter views on Recovery Bond structures and key components thereof; proposed investor lists; the proposed cost structure; proposed underwriting fees; additional structural elements (including early redemption features and green bond certifications), and views on tranche sizing and pricing to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms. Based on information provided by PG&E, the Finance Team accepted the selection of underwriters noting their relevant experience and execution expertise, including participation in previous issuances, and the criteria used by PG&E to evaluate underwriters.

Underwriter economics were reviewed with PG&E, including review of comparable issuances and the role and scope of this process.

**3. Credit Rating Agency Review**

Pursuant to the Decision, the Finance Team was directed to review the credit rating agency materials associated with the Recovery Bonds.[8] PG&E provided the Finance Team with access to information provided to the rating agencies, including previewing information with the Finance Team. All aspects of the process, including confidential materials shared with the rating agencies were also made available to the Finance Team.

---

[7] Decision, Ordering ¶ 3.

[8] Decision, Ordering ¶ 3.

The Finance Team reviewed the credit rating process, related materials, call recordings, and the approach to presentations and the application for credit ratings. With the Finance Team's input on certain information shared with credit ratings, PG&E applied for and received preliminary "triple A" ratings from two of the major rating agencies with final Aaa(sf)(Moody's)/ AAA(sf)(S&P) ratings expected to be confirmed at closing.

PG&E also reviewed potential green bond certification options with the Finance team, including potential certification providers, the associated costs and potential benefits of obtaining such certification. The Finance Team approved pursuit of the green bond certification after requesting it, which was obtained to further broaden potential investors and resulting potential customer savings.

### 4. Preparation and Marketing of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review the underwriters' preparation, marketing and syndication of the proposed Recovery Bonds, including indicative pricing.[9] The Finance Team also had the right to review the marketing approach for the Recovery Bonds.[10]

In meetings with PG&E, the Finance Team explored the risks and benefits of the proposed marketing plan for the Recovery Bonds. PG&E and its structuring advisor presented the proposed structure to the Finance Team and its proposal to market to a broad range of ABS and corporate investors. The Finance Team actively followed, and commented on, the evaluation of potential structures, including requesting the review of and evaluating alternative structures, focusing on maximizing investor participation to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms.

The Finance Team considered input from PG&E and its underwriters on market conditions and expectations as well as investor demand to assist in determining the suitable timing to go to market and the final size and structure of the offering. PG&E and its lead underwriters provided the Finance Team with assessments on market timing and structure based on key indicators such as, market conditions, unpredictability on future rates, availability of investor capital and the potential for other transactions to compete with the issuance of this series of Recovery Bonds.

After evaluation of a broad range of potential alternatives, PG&E ultimately selected, with the Finance Team's concurrence, a proposed structure that was anticipated to produce the greatest amount of investor interest, highest present value savings and lowest

[9] Decision, Ordering ¶ 3.

[10] Decision, Ordering ¶ 3.

weighted average interest rate on the Recovery Bonds relative to alternative structures. Having conducted its review and provided input and comments on the proposed structuring and marketing of the Recovery Bonds, the Finance Team accepted the approach to register the Recovery Bonds with the Securities and Exchange Commission on a Form SF-1 to facilitate greater liquidity and identify the Recovery Bonds as not "asset-backed securities" as such term is defined by the SEC in governing regulations Item 1101 of Regulation AB.

With the opportunity to provide comment by the Finance Team, PG&E developed and implemented a marketing and structuring plan to incentivize underwriters to market the Recovery Bonds to their customers and to reach out to a broad base of potential investors, including both corporate and ABS investors and investors who have not previously purchased this type of security. PG&E held a group roadshow and opportunities for potential investors to have one-on-one and small group calls with PG&E management and the underwriters.

Pursuant to the Decision, the Finance Team reviewed and provided input on certificates provided by PG&E and the lead underwriters, necessary to further align interests and ensure the statutory objective was achieved.[11]

The Finance Team was apprised that PG&E held market update discussions with the underwriting team to develop recommendations for pricing. PG&E and the Finance Team met with the underwriting team before and during the marketing phase. The Finance Team's Financial Advisor engaged with the underwriters on key elements of the marketing, pricing, and syndication process including participating in market updates, pricing discussions and roadshows, using such information to inform the Finance Team's review and feedback on the structure and marketing process. This process included participating in pricing discussions, review of subscriptions, and modifications available, focused on meeting the statutory objective.

### 5. Transaction Fees and Costs

Pursuant to the Decision, the Finance Team had the right to review all transaction fees and costs for the Recovery Bonds, including Upfront Financing Costs and other Financing Costs.[12] That includes reviewing and approving servicing and administrative fees and associated crediting, and any return on equity contribution.[13]

[11] Decision, Ordering ¶ 3.

[12] Decision, Ordering ¶ 3.

[13] Decision, Ordering ¶ 3.

The Finance Team asked questions and provided input on the fees and costs for the Recovery.

Bonds, including a review of pricing comparisons and amounts separately credited back by PG&E. The Finance Team provided feedback on various aspects of the fees and costs for the Recovery Bonds. As determined in the Financing Order, the transaction also included a credit enhancement for the Recovery Bonds in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount of the Recovery Bonds. The rate of return on this amount, tied to the cost of the securitization, was also determined in the Financing Order, and reviewed by the Finance Team.

### 6. Collateral and Credit Enhancements

Pursuant to the Decision, the Finance Team was directed to determine whether over-collateralization and other additional credit enhancements would be required for the transaction.[14] In response to the Finance Team's inquiries and input, PG&E confirmed no additional enhancements would be required to obtain the highest possible credit rating and achieve the statutory objective.

### 7. Sale of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review all material terms of the Recovery Bonds in a negotiated offering through one or more underwriters.[15] The Finance Team worked with PG&E and the underwriters (and each of their respective counsels) to finalize documentation in accordance with established standards for transactions of this sort and the terms of the Decision. The Finance Team was apprised of developments in the marketing process, including the roadshow process and results, the level of interest from investors, questions raised throughout the process and pricing implications.

## V. CONCLUSION

The Finance Team has completed its pre-issuance review and approves the material terms of the Recovery Bonds in the Draft Issuance Advice Letter in accordance with the Decision (pending review of ultimately proposed final sizing and pricing levels). Based on the materials that the Finance Team has received and reviewed, the Finance Team is satisfied that the issuance of the Recovery Bonds as proposed would reduce, to the maximum extent possible, consumer rates on a present value basis as compared to the use of traditional utility financing mechanisms.

---

[14] Decision, Ordering ¶ 3.

[15] Decision, Ordering ¶ 3.

Christine Jun Hammond

Christine Jun Hammond
General Counsel

Leuwam Tesfai

Leuwam Tesfai
Deputy Executive Director for Energy and Climate Policy

# EXHIBIT A

# Draft Issuance Advice Letter

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

[ ], 2022

**Advice [ ]-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**<u>Subject:</u>** **Issuance Advice Letter Submission for Wildfire Hardening Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 22-08-004 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Wildfire Hardening Recovery Bonds, the initial Fixed Recovery Charges for the series. This Issuance Advice Letter is for the Wildfire Hardening Senior Secured Recovery Bonds Series 2022-A, Tranche(s) A-1, A-2, and A-3 ("Wildfire Hardening Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 4 is the Finance Team's pre-issuance approval letter dated [Pricing Date], 2022.

## <u>Purpose</u>

This submission establishes initial Fixed Recovery Charges for rate schedules for Consumers. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"), including the Billing Commencement Date. Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Upfront Financing Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## <u>Background</u>

In D. 22-08-004, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Wildfire Hardening Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the rate design methodology and Fixed Recovery Charge cash flow formula (the "adjustment mechanism") found reasonable by the Commission in D. 22-08-004 to establish initial Fixed Recovery Charges for a series of Wildfire Hardening Recovery Bonds. Using this methodology and formula approved by the Commission in D. 22-08-004, this submission establishes the initial Fixed Recovery Charges.

**Issuance Information:**

Decision 22-08-004 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2022-A
Recovery Property Owner (SPE): PG&E Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: [November 30], 2022
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued (Authorized Amount): (See Table 1 below)
Upfront Financing Costs: (See Table 2 below)
Upfront Financing Costs as a Percent of Principal Amount Issued: 0.85%
Coupon Rate(s): See Exhibit 1
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): See Exhibit 1
Legal Maturity Date(s): See Exhibit 1
Payment Dates (semi-annually): January 15 and July 15
Annual Servicing Fee as a percent of the issuance amount: .05%
Overcollateralization amount for the series, if any: None
FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: January 1, 2023
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**Securitized Amount:**

The following table sets forth the computation of the final Authorized Amount (i.e., the principal amount of the Recovery Bonds).

| Table 1: Authorized Amount | |
|---|---|
| Second AB 1054 CapEx Amount: Approved in D.20-12-005 | $975,000,000 |
| Upfront Financing Costs (See Table 2 below) | $8,362,000 |
| Total Securitized Amount | $983,362,000 |

The amounts set forth in Table 1 are within the amounts approved as recovery costs in D. 22-08-004. PG&E has determined that Community Wildfire Safety Program (CWSP) system hardening costs approved in D.20-12-005 and to be recovered through issuance of the Wildfire Hardening Recovery Bonds described herein do not exceed 115 percent of the Commission-approved per-mile costs set forth in D.20-12-005 at page 119.

**Upfront Financing Costs:**

The following table includes actual or estimated (as noted) Upfront Financing Costs to be incurred in connection with the issuance of the Wildfire Hardening Recovery Bonds:

| **Table 2<br>Upfront Financing Costs** | |
|---|---|
| Underwriters' Fees and Expenses | $3,933,448 |
| Legal Fees and Expenses | 1,245,000 |
| Rating Agency Fees | 1,130,866 |
| Accounting Fees and Expenses | 125,000 |
| PG&E's Advisory Fee | 255,000 |
| Servicer Set-up Costs | 0 |
| SEC Registration Fees | 108,366 |
| Section 1904 Fees | 497,681 |
| Printing / EDGARizing Expenses | 150,000 |
| Trustee / Trustee Counsel Fee and Expenses | 41,500 |
| Original Issue Discount | [TBD upon pricing] |
| Commission's Costs and Expenses | 676,000 |
| Miscellaneous | [TBD by size of OID] |
| | |
| **Total** | **$8,362,000** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 22-08-004. | |

**True-Up Mechanism:**

Changes to the Fixed Recovery Charges will be requested through the submission of Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters in accordance with Decision 22-08-004. Annually before each FRC Annual Adjustment Date (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Wildfire Hardening Recovery Bonds), and if determined necessary by the servicer, semi-annually and more frequently, the servicer will submit Routine True-Up Mechanism Advice Letters in the form of Attachment 3 to the Financing Order to ensure that Fixed Recovery Charges collections be sufficient to make all scheduled payments of bond principal, interest, and other Ongoing Financing Costs on a timely basis during each of the two payment periods and, in the case of semi-annual Routine True-Up Mechanism Advice Letter, to replenish any draws upon the capital subaccount. The first payment period means the period commencing on the Closing Date and ending (and including) the first Payment Date following the Closing Date (the "First Payment Period"); the second payment period means the period commencing on the day following the first Payment Date following the adjustment date and ending on (and including) the next Payment Date (the "Second Payment Period"). The servicer may also submit Non-Routine True-Up Mechanism Advice Letters in the form of Attachment 4 to the Financing Order.

**Ongoing Financing Costs:**

The following table includes estimated Ongoing Financing Costs for the First and Second Payment periods following Closing Date to be recovered through Fixed Recovery Charges in accordance with the Financing Order.

| **Table 3: Estimated Ongoing Financing Costs** | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Servicing Fee (PG&E as Servicer) (0.05% of the initial principal amount of the Wildfire Hardening Recovery Bonds) | $307,301 | $245,841 |
| Administration Fee | 46,875 | 37,500 |
| Accounting Fees and Expenses | 31,250 | 31,250 |
| Legal Fees and Expenses | 17,500 | 17,500 |
| Rating Agency Surveillance Fees | 20,000 | 20,000 |
| Trustee Fees and Expenses | 7,725 | 7,725 |
| Independent Director Fees | 750 | 750 |
| Printing / EDGARizing Expenses | 5,000 | 5,000 |
| Return on Equity | [TBD] | [TBD] |
| Miscellaneous Fees and Expenses | 5,000 | 5,000 |
| | | |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$441,401** | **$370,566** |
| Ongoing Servicers Fee (Third Party as Servicer) (0.60% of initial principal amount) | $3,687,608 | $2,950,086 |
| **TOTAL ONGOING FINANCING COSTS (Third Party as Servicer)** | **$3,821,708** | **$3,074,811** |

**Fixed Recovery Charges:**

Table 4 below shows the inputs and current assumptions for each of the variables used in calculating the Fixed Recovery Charges.

| **Table 4: Input Values For Fixed Recovery Charges** | | |
|---|---|---|
| | First Payment Period | Second Payment Period |

| | | |
|---|---|---|
| Allocation Factors for each Customer Class (see Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Projected kWh sales for each Customer Class for payment period (See Exhibit 3) | See Exhibit 3 | See Exhibit 3 |
| Percent of Consumers' revenue written off | 0.34% | 0.34% |
| Average Days Sales Outstanding | 55 | 55 |
| Ongoing Financing Costs for the applicable payment period (See Table 3 above) | 441,401 | 370,566 |
| Wildfire Hardening Recovery Bond Principal | [ ] | [ ] |
| Wildfire Hardening Recovery Bond Interest | [ ] | [ ] |
| Periodic Payment Requirement (See Exhibit 2) | [ ] | [ ] |
| Periodic Billing Requirement (See Exhibit 3) | [ ] | [ ] |

Table 5 shows the initial Fixed Recovery Charges for each FRC Consumer Class. The Fixed Recovery Charge calculations are shown in Exhibit 3.

| **Table 5: Fixed Recovery Charges (cent per kWh)** | |
|---|---|
| **FRC Consumer Class** | **WHC*** |
| Residential | |
| Residential – CARE | |
| Residential – Non-CARE | |
| Small Commercial | |
| Medium Commercial | |
| Medium Commercial – A/B-10T | |
| Medium Commercial – A/B-10P | |
| Medium Commercial – A/B-10S | |
| E/B-19 | |
| E/B-19T | |
| E/B-19P | |
| E/B-19S | |
| Streetlight | |
| Standby | |
| Standby – STOU T | |
| Standby – STOU P | |
| Standby – STOU S | |
| Agriculture | |
| E/B-20 | |
| E/B-20 T | |
| E/B-20 P | |
| E/B-20 S | |
| Average Bundled Rate | |
| **Direct Access/Community Choice Aggregation (DA/CCA)** | |
| Residential | |
| Residential – CARE | |

| | |
|---|---|
| Residential – Non-CARE | |
| Small Commercial | |
| Medium Commercial | |
| Medium Commercial – A/B-10T | |
| Medium Commercial – A/B-10P | |
| Medium Commercial – A/B-10S | |
| E/B-19 | |
| E/B-19T | |
| E/B-19P | |
| E/B-19S | |
| Streetlight | |
| Standby | |
| Standby – STOU T | |
| Standby – STOU P | |
| Standby – STOU S | |
| Agriculture | |
| E/B-20 | |
| E/B-20 T | |
| E/B-20 P | |
| E/B-20 S | |
| Average Bundled Rate | |
| Average DA/CCA Rate | |

*Class average rates are calculated by dividing total revenues expected to be collected by the WHC by total forecasted system sales for the class for the rate effective period.

**Recovery Property:**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charges set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charges set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 2, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charges, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charges under the True-Up Mechanism.

These Fixed Recovery Charges, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 2 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Proposed Tariff Changes:**

PG&E will submit all tariff sheets reflecting the revised Fixed Recovery Charges shown in Table 5 in the consolidated revenue requirement and rate change advice letter for rates effective on January 1, 2023.

**Effective Date**

In accordance with Decision 22-08-004, unless before noon on the fourth business day after pricing the Commission staff rejects this Issuance Advice Letter for failure to adhere to the terms of the Financing Order, the Issuance Advice Letter and the Fixed Recovery Charges established by this Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charges will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes. Further all Upfront Financing Costs and all Ongoing Financing Costs for the life of the Wildfire Hardening Recovery Bonds shall be recoverable as provided in the Financing Order.

**Description of Exhibits:**

Exhibit 1 presents the debt service schedule for the Wildfire Hardening Recovery Bonds, including expected principal amortization, scheduled final payment dates and final legal maturity dates, interest rates, and aggregate scheduled debt service per payment date.

Exhibit 2 presents the Periodic Payment Requirements related to the Wildfire Hardening Recovery Bonds for the two payment periods following the Closing Date.

Exhibit 3 presents the Fixed Recovery Charges calculations.

Exhibit 4 provides the pre-issuance approval letter of the Finance Team.

**Notice**

In accordance with General Order 96-B, Section 4.4, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list. Address changes should be directed to PG&E at email address PGETariffs@pge.com. Advice letter submissions can also be accessed electronically at: https://www.pge.com/tariffs/advice-letters.page. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

**Attachments**

Attachment 1: Exhibits 1-4

Exhibit 1: Recovery Bond Terms and Debt Service Schedule

Exhibit 2: Periodic Payment Requirements

Exhibit 3: Fixed Recovery Charges Calculations

Exhibit 4: Pre-Issuance Approval Letter of the Finance Team

cc: Service List for A.22-03-010

**PG&E Gas and Electric**
**Advice Submittal List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell
Dish Wireless L.L.C.

East Bay Community Energy Ellison
Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
iCommLaw
International Power Technology
Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.

Resource Innovations

SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

May 4, 2022

**Advice 6579-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject:** **Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 21-05-015 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Recovery Bonds, the initial Fixed Recovery Charge for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series 2022-A, Tranche(s) A-1, A-2, A-3, A-4 and A-5 ("Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 5 is the Finance Team's pre-issuance approval letter dated May 3, 2022.

## Purpose

This submission establishes initial Fixed Recovery Charge for rate schedules for Consumers, including the Billing Commencement Date. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"). Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Bond Issuance Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In D. 21-05-015, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the bond sizing methodology and Fixed Recovery Charge formulas found reasonable by the Commission in D. 21-05-015 to establish initial Fixed Recovery Charge for a series of Recovery Bonds. Using the

methodology approved by the Commission in D. 21-05-015, this submission establishes the initial Fixed Recovery Charge.

**Issuance Information:**

Decision 21-05-015 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2022-A
Recovery Property Owner (SPE): PG&E Wildfire Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: May 10, 2022
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody’s)
Principal Amount Issued: $3,600,000,000
Bond Issuance Costs: $22,398,887 (See Table 1 below)
Bond Issuance Costs as a Percent of Principal Amount Issued: 0.62%
Recovery Costs Financed: $3,577,601,113
Coupon Rate(s): 3.59% (Tranche A-1); 4.26% (Tranche A-2); 4.38% (Tranche A-3); 4.45% (Tranche A-4) and 4.67% (Tranche A-5)
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): June 3, 2030 (Tranche A-1); June 2, 2036 (Tranche A-2); June 1, 2039 (Tranche A-3); December 2, 2047 (Tranche A-4); and December 1, 2051 (Tranche A-5)
Legal Maturity Date(s): June 1, 2032 (Tranche A-1); June 1, 2038 (Tranche A-2); June 3, 2041 (Tranche A-3); December 1, 2049 (Tranche A-4); and December 1, 2053 (Tranche A-5)
Payment Dates (semi-annually): June 1 and December 1
Annual Servicing Fee as a percent of the issuance amount: 0.05%
Overcollateralization amount for the series, if any: None
Principal Amount of Recovery Property Established: $3,577,601,113
FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: June 1, 2022
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**Bond Issuance Costs:**

| Table 1<br>Bond Issuance Costs | |
|---|---|
| Underwriter Fees and Expenses | $14,400,000 |
| Legal Fees and Expenses | 2,667,253 |
| SEC Registration Fees | 333,720 |
| Rating Agency Fees | 1,285,000 |
| Accounting Fees and Expenses | 125,000 |
| Section 1904 Fees[1] | 756,000 |
| Printing/Edgarizing Costs | 150,000 |
| Servicer Set-up Costs | 3,000 |
| Bond Trustee Fees and Expenses | 60,000 |
| Original Issue Discount | 107,874 |
| Company Advisory Fee | 750,000 |
| Miscellaneous | 250,000 |
| Costs of the Commission | 1,511,040 |
| **Total** | **$22,398,887** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 21-05-015. | |

**True-Up Mechanism:**

Not less often than annually, the servicer will compare the actual principal amortization with the scheduled principal amortization as set forth in Exhibit 1. If the servicer forecasts that Fixed Recovery Charge collections will be insufficient to make all scheduled payments of bond principal, interest, and related costs on a timely basis during the current or next succeeding payment period or to replenish any draws upon the capital subaccount, a change to the Fixed Recovery Charge will be requested via a Routine True-Up Mechanism Advice Letter or Non- Routine True-Up Mechanism Advice Letter in accordance with Decision 21-05-015.

**Ongoing Financing Costs:**

| Table 2<br>Estimated Ongoing Financing Costs | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $1,005,000 | $900,000 |
| Administration Fee | 69,792 | 62,500 |
| Accountant's Fee | 62,500 | 62,500 |
| Legal Fees/Expenses for PG&E's/Issuer's Counsel | 17,500 | 17,500 |
| Bond Trustee's/ Bond Trustee's Counsel Fees and Expenses | 8,500 | 8,500 |
| Independent Managers' Fees | 1,500 | 1,500 |
| Rating Agency Fees | 20,000 | 20,000 |
| Printing/Edgarizing Fees | 5,000 | 5,000 |
| Miscellaneous | 5,000 | 5,000 |
| Return on Equity | 450,441 | 403,380 |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$1,645,233** | **$1,485,880** |

**Fixed Recovery Charge:**

Table 3 below shows the current assumptions for each of the variables used in the Fixed Recovery Charge calculation.

| Table 3<br>Input Values For Fixed Recovery Charge[1] | |
|---|---|
| kWh sales for the applicable period | 64,578,664,427 |
| Percent of revenue requirement allocated to Consumers | 100% |
| Percent of Consumers' revenue written off (Res/Non-Res) | 0.42%/0.08% |
| Percent of Consumers' billed amounts expected to be uncollected | 0.34% |
| Percent of billed amounts collected in current month | 31.10% |
| Percent of billed amounts collected in second month after billing | 56.46% |
| Percent of billed amounts collected in third month after billing | 9.28% |
| Percent of billed amounts collected in fourth month after billing | 1.22% |
| Percent of billed amounts collected in fifth month after billing | 1.03% |
| Percent of billed amounts collected in sixth month after billing | 0.57% |
| Ongoing Financing Costs for the applicable period | See Table 2 |
| Expected Fixed Recovery Charge outstanding balance as of_5/4/2022____ | See Exhibit 3 |

[1] Applicable period from June 1, 2022 through May 31, 2023.

Table 4 shows the initial Fixed Recovery Charge calculated for Consumers. The Fixed Recovery Charge calculations are shown in Exhibit 2.

| Table 4 | |
|---|---|
| Consumers Fixed Recovery Charge[2] | 0.548 ¢/kWh |

Exhibit 4 includes proposed changes to Part IX of PG&E's Preliminary Statement to show the Fixed Recovery Charge rate value which is to be effective June 1, 2022. Preliminary Statement Part IX is included in this advice letter on an illustrative basis and will be submitted again in PG&E's June rate change advice letter before it is made effective on June 1, 2022.

**Recovery Property:**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charge set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charge set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 3, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charge, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charge under the True-Up Mechanism.

These Fixed Recovery Charge, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 3 are paid in full to the owner of the Recovery Property, or its assignee(s).

[2] For residential rates, PG&E shall retain the total rate relationships by tier determined by D.15-07-001 with the addition of the Fixed Recovery Charge and Customer Credit.

**Description of Exhibits**

Exhibit 1 to this Issuance Advice Letter presents the scheduled principal amortization schedule for the Recovery Bonds.

Exhibit 2 presents the Fixed Recovery Charge calculations.

Exhibit 3 presents the amounts receivable and expected principal amount amortization.

Exhibit 4 provides proposed changes to Part IX of PG&E's Preliminary Statement.

Exhibit 5 provides the pre-issuance approval letter of the Finance Team.

**Effective Date**

In accordance with Decision 21-05-015, unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter, the Issuance Advice Letter and the Fixed Recovery Charge established by an Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charge will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.21-01-004. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

Attachments
Attachment 1: Exhibits 1-5

cc: Service List for A.21-01-004

California Public Utilities Commission

# ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6579-E
Tier Designation: 1

Subject of AL: Issuance Advice Letter Submission for Recovery Bonds

Keywords (choose from CPUC listing): Compilance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-05-015

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information: See Confidentiality Declaration & Matrix Attachment
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are **to be sent via email and are** due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

| | |
|---|---|
| California Public Utilities Commission<br>Energy Division Tariff Unit Email:<br>EDTariffUnit@cpuc.ca.gov | Contact Name: Sidney Bob Dietz II, c/o Megan Lawson<br>Title: Director, Regulatory Relations<br>Utility/Entity Name: Pacific Gas and Electric Company<br><br>Telephone (xxx) xxx-xxxx: (415)973-2093<br>Facsimile (xxx) xxx-xxxx: (415)973-3582<br>Email: PGETariffs@pge.com |
| | Contact Name:<br>Title:<br>Utility/Entity Name:<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: |

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Advice 6579-E

# Attachment 1

Advice 6579-E

# Exhibit 1

## Scheduled Principal Amortization Schedule For The Recovery Bonds

**Exhibit 1**
**Recovery Bond Terms and Debt Service Schedule**

| Tranche | Expected Weighted Average Life | Principal Amount Offered | Scheduled Final Payment Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|---|
| A-1 | 4.33 | $540,000,000 | 6/3/2030 | 6/1/2032 | 3.59% |
| A-2 | 11.07 | $540,000,000 | 6/2/2036 | 6/1/2038 | 4.26% |
| A-3 | 15.52 | $360,000,000 | 6/1/2039 | 6/3/2041 | 4.38% |
| A-4 | 21.55 | $1,260,000,000 | 12/2/2047 | 12/1/2049 | 4.45% |
| A-5 | 27.70 | $900,000,000 | 12/1/2051 | 12/1/2053 | 4.67% |
| | | $3,600,000,000 | | | |

**Tranche A-1**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 5/10/2022 | $540,000,000 | $0 | $0 | $0 |
| 12/1/2022 | $506,611,046 | $33,388,954 | $10,835,910 | $44,224,864 |
| 6/1/2023 | $475,896,548 | $30,714,498 | $9,103,800 | $39,818,298 |
| 12/1/2023 | $444,570,830 | $31,325,718 | $8,551,861 | $39,877,579 |
| 6/1/2024 | $412,621,732 | $31,949,098 | $7,988,938 | $39,938,036 |
| 12/1/2024 | $380,036,846 | $32,584,886 | $7,414,813 | $39,999,699 |
| 6/1/2025 | $346,803,521 | $33,233,325 | $6,829,262 | $40,062,587 |
| 12/1/2025 | $312,908,852 | $33,894,669 | $6,232,059 | $40,126,728 |
| 6/1/2026 | $278,339,681 | $34,569,171 | $5,622,972 | $40,192,143 |
| 12/1/2026 | $243,082,582 | $35,257,099 | $5,001,764 | $40,258,863 |
| 6/1/2027 | $207,123,868 | $35,958,714 | $4,368,194 | $40,326,908 |
| 12/1/2027 | $170,449,574 | $36,674,294 | $3,722,016 | $40,396,310 |
| 6/1/2028 | $133,045,462 | $37,404,112 | $3,062,979 | $40,467,091 |
| 12/1/2028 | $94,897,008 | $38,148,454 | $2,390,827 | $40,539,281 |
| 6/1/2029 | $55,989,401 | $38,907,607 | $1,705,299 | $40,612,906 |
| 12/1/2029 | $16,307,532 | $39,681,869 | $1,006,130 | $40,687,999 |
| 6/1/2030 | $0 | $16,307,532 | $293,046 | $16,600,578 |

**Exhibit 1**
**Tranche A-2**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 5/10/2022 | $540,000,000 | | | |
| 12/1/2022 | $540,000,000 | $0 | $12,852,945 | $12,852,945 |
| 6/1/2023 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2023 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2024 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2024 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2025 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2025 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2026 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2026 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2027 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2027 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2028 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2028 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2029 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 12/1/2029 | $540,000,000 | $0 | $11,510,100 | $11,510,100 |
| 6/1/2030 | $515,835,992 | $24,164,008 | $11,510,100 | $35,674,108 |
| 12/1/2030 | $474,501,077 | $41,334,915 | $10,995,044 | $52,329,959 |
| 6/1/2031 | $432,244,393 | $42,256,684 | $10,113,990 | $52,370,674 |
| 12/1/2031 | $389,045,384 | $43,199,009 | $9,213,289 | $52,412,298 |
| 6/1/2032 | $344,883,038 | $44,162,346 | $8,292,502 | $52,454,848 |
| 12/1/2032 | $299,735,872 | $45,147,166 | $7,351,182 | $52,498,348 |
| 6/1/2033 | $253,581,924 | $46,153,948 | $6,388,870 | $52,542,818 |
| 12/1/2033 | $206,398,742 | $47,183,182 | $5,405,099 | $52,588,281 |
| 6/1/2034 | $158,163,376 | $48,235,366 | $4,399,389 | $52,634,755 |
| 12/1/2034 | $108,852,361 | $49,311,015 | $3,371,252 | $52,682,267 |
| 6/1/2035 | $58,441,710 | $50,410,651 | $2,320,188 | $52,730,839 |
| 12/1/2035 | $6,906,902 | $51,534,808 | $1,245,685 | $52,780,493 |
| 6/1/2036 | $0 | $6,906,902 | $147,221 | $7,054,123 |

**Exhibit 1**
**Tranche A-3**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 5/10/2022 | $360,000,000 | | | |
| 12/1/2022 | $360,000,000 | $0 | $8,797,770 | $8,797,770 |
| 6/1/2023 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2023 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2024 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2024 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2025 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2025 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2026 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2026 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2027 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2027 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2028 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2028 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2029 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2029 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2030 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2030 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2031 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2031 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2032 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2032 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2033 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2033 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2034 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2034 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2035 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 12/1/2035 | $360,000,000 | $0 | $7,878,600 | $7,878,600 |
| 6/1/2036 | $314,222,868 | $45,777,132 | $7,878,600 | $53,655,732 |
| 12/1/2036 | $260,295,313 | $53,927,555 | $6,876,767 | $60,804,322 |
| 6/1/2037 | $205,084,284 | $55,211,029 | $5,696,563 | $60,907,592 |
| 12/1/2037 | $148,559,231 | $56,525,053 | $4,488,270 | $61,013,323 |
| 6/1/2038 | $90,688,883 | $57,870,348 | $3,251,219 | $61,121,567 |
| 12/1/2038 | $31,441,219 | $59,247,664 | $1,984,726 | $61,232,390 |
| 6/1/2039 | $0 | $31,441,219 | $688,091 | $32,129,310 |

**Exhibit 1**
**Tranche A-4**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 5/10/2022 | $1,260,000,000 | $0 | $0 | $0 |
| 12/1/2022 | $1,260,000,000 | $0 | $31,312,785 | $31,312,785 |
| 6/1/2023 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2023 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2024 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2024 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2025 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2025 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2026 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2026 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2027 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2027 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2028 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2028 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2029 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2029 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2030 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2030 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2031 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2031 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2032 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2032 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2033 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2033 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2034 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2034 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2035 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2035 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2036 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2036 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2037 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2037 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2038 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 12/1/2038 | $1,260,000,000 | $0 | $28,041,300 | $28,041,300 |
| 6/1/2039 | $1,230,783,462 | $29,216,538 | $28,041,300 | $57,257,838 |
| 12/1/2039 | $1,168,642,608 | $62,140,854 | $27,391,086 | $89,531,940 |
| 6/1/2040 | $1,104,938,911 | $63,703,697 | $26,008,141 | $89,711,838 |
| 12/1/2040 | $1,039,633,067 | $65,305,844 | $24,590,415 | $89,896,259 |
| 6/1/2041 | $972,684,780 | $66,948,287 | $23,137,034 | $90,085,321 |
| 12/1/2041 | $904,052,744 | $68,632,036 | $21,647,100 | $90,279,136 |
| 6/1/2042 | $833,694,612 | $70,358,132 | $20,119,694 | $90,477,826 |
| 12/1/2042 | $761,566,974 | $72,127,638 | $18,553,874 | $90,681,512 |
| 6/1/2043 | $687,625,325 | $73,941,649 | $16,948,673 | $90,890,322 |
| 12/1/2043 | $611,824,043 | $75,801,282 | $15,303,102 | $91,104,384 |
| 6/1/2044 | $534,116,359 | $77,707,684 | $13,616,144 | $91,323,828 |
| 12/1/2044 | $454,454,328 | $79,662,031 | $11,886,760 | $91,548,791 |
| 6/1/2045 | $372,788,796 | $81,665,532 | $10,113,881 | $91,779,413 |
| 12/1/2045 | $289,069,375 | $83,719,421 | $8,296,415 | $92,015,836 |
| 6/1/2046 | $203,244,412 | $85,824,963 | $6,433,239 | $92,258,202 |
| 12/1/2046 | $115,260,950 | $87,983,462 | $4,523,204 | $92,506,666 |
| 6/1/2047 | $25,064,706 | $90,196,244 | $2,565,132 | $92,761,376 |
| 12/1/2047 | $0 | $25,064,706 | $557,815 | $25,622,521 |

**Exhibit 1**
**Tranche A-5**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 5/10/2022 | $900,000,000 | $0 | $0 | $0 |
| 12/1/2022 | $900,000,000 | $0 | $23,486,850 | $23,486,850 |
| 6/1/2023 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2023 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2024 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2024 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2025 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2025 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2026 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2026 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2027 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2027 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2028 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2028 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2029 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2029 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2030 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2030 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2031 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2031 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2032 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2032 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2033 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2033 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2034 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2034 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2035 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2035 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2036 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2036 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2037 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2037 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2038 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2038 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2039 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2039 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2040 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2040 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2041 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2041 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2042 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2042 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2043 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2043 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2044 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2044 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2045 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2045 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2046 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2046 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 6/1/2047 | $900,000,000 | $0 | $21,033,000 | $21,033,000 |
| 12/1/2047 | $832,600,025 | $67,399,975 | $21,033,000 | $88,432,975 |
| 6/1/2048 | $737,732,347 | $94,867,678 | $19,457,863 | $114,325,541 |
| 12/1/2048 | $640,369,649 | $97,362,698 | $17,240,805 | $114,603,503 |
| 6/1/2049 | $540,446,312 | $99,923,337 | $14,965,439 | $114,888,776 |
| 12/1/2049 | $437,894,993 | $102,551,319 | $12,630,230 | $115,181,549 |
| 6/1/2050 | $332,646,572 | $105,248,421 | $10,233,606 | $115,482,027 |
| 12/1/2050 | $224,630,119 | $108,016,453 | $7,773,950 | $115,790,403 |
| 6/1/2051 | $113,772,833 | $110,857,286 | $5,249,606 | $116,106,892 |
| 12/1/2051 | $0 | $113,772,833 | $2,658,871 | $116,431,704 |

Advice 6579-E

# Exhibit 2

## Fixed Recovery Charge Calculation

# Exhibit 2
# Fixed Recovery Charge Calculation

| (A) | (B) | (C) = (A) / (B) |
|---|---|---|
| Highest Periodic Billing Requirement ($) | Forecasted Billed and Collected Sales for Highest Periodic Requirement (MWh) | Fixed Recovery Charge (¢/kWh)[1] |
| 122,320,447 | 22,338,467 | 0.548 |

[1] Fixed Recovery Charge is applicable to non-CARE and non-FERA consumers.

Advice 6579-E

# Exhibit 3

## Amounts Receivable And Expected Principal Amount Amortization

**Exhibit 3**
**Periodic Payment Requirements**

The total amount payable to the owner of the Recovery Property, or its assignee(s), pursuant to this issuance advice letter is a $ principal amount, plus interest on such principal amount, plus other Financing Costs, to be obtained from Fixed Recovery Charges calculated in accordance with D. 21-05-015

The Fixed Recovery Charges shall be adjusted from time to time, at least annually, via the Routine True-Up Mechanism Advice Letter and Non-Routine True-Up Mechanism Advice Letter in accordance with the Decision.

The following amounts are scheduled to be paid by the Bond Trustee from Fixed Recovery Charges it has received during the two Payment Periods following the Closing Date. These payment amounts include principal plus interest and plus other Ongoing Financing Costs.

| Payment Period | Recovery Bond Payments (See Exhibit 1) | Ongoing Financing Costs (see Table 2) | Periodic Payment Requirement |
|---|---|---|---|
| **First Payment Period** | $120,675,214.00 | $1,645,232.67 | $122,320,446.67 |
| **Second Payment Period** | $108,281,298.50 | $1,485,880.00 | $109,767,178.50 |

Advice 6579-E

# Exhibit 4

## Proposed Changes To Part IX Of PG&E’s Preliminary Statement

**ELECTRIC PRELIMINARY STATEMENT PART IX** Sheet 1
FIXED RECOVERY CHARGE

IX. Fixed Recovery Charge

1. PURPOSE:

The purpose of this section is to establish a Fixed Recovery Charge, as mandated by Article 5.8, Chapter 4, Part 1, Division 1 of the California Public Utilities Code (Article 5.8). Article 5.8 authorizes PG&E to recover a portion of its costs associated with catastrophic wildfires ignited in 2017 (Catastrophic Wildfire Amounts) through the issuance of Recovery Bonds. The Fixed Recovery Charge is defined by Article 5.8 as a nonbypassable, separate charge that is authorized by the Commission in a Financing Order to recover the Catastrophic Wildfire Amounts and financing costs associated with the Recovery Bonds. The Fixed Recovery Charge will be composed of the following costs: (1) interest and principal on the Recovery Bonds, (2) administration and servicing fees, (3) Bond Trustee fees and other expenses, (4) any credit enhancements, (5) allowance for uncollectibles, (6) replenishing the capital subaccount, (7) authorized rate of return on PG&E's equity contribution to the Special Purpose Entity (SPE), and (8) other financing costs. A separate Fixed Recovery Charge will apply to each series of Recovery Bonds issued. The aggregate amount of applicable Fixed Recovery Charges will appear on customers' bills under one line item called "Recovery Bond Charge (RBC)." (N) | (N)

The rights in and to the Fixed Recovery Charge established pursuant to the Financing Order constitute "recovery property" as defined in the legislation and have been established pursuant to a Financing Order (Decision (D.) 21-05-015) issued by the California Public Utilities Commission.

Concurrently with the effectiveness of the Fixed Recovery Charge, PG&E has sold all of its rights with respect to such recovery property to [(SPE)], a Delaware Limited Liability Company (SPE). The recovery property includes the right, title, and interest of PG&E 1) in and to the Fixed Recovery Charges, including all rights to obtain adjustments to the Fixed Recovery Charges as provided in the Financing Order, and 2) to be paid the amount that is determined in the Financing Order that PG&E is lawfully entitled to receive pursuant to the provisions of Article 5.8 and the proceeds thereof, and all revenues, collections, claims, payments, money, or proceeds of or arising from Fixed Recovery Charges that are subject of the Financing Order. PG&E has no rights to the recovery property, Fixed Recovery Charge or any amounts payable thereunder.

2. APPLICABILITY:

This Fixed Recovery Charge shall apply to all customers[1] except for those customers participating in the California Alternate Rates for Energy or Family Electric Rate Assistance programs pursuant to Section 850.1(i).



[1] References to "customer" include the term "consumer" as defined in Section 850(b)(3) and as used in Section 850.1(b). *See* Pub. Util. Code § 850(b)(3) ("'Consumer' means any individual, governmental body, trust, business entity, or nonprofit organization that consumes electricity that has been transmitted or distributed by means of electric transmission or distribution facilities, whether those electric transmission or distribution facilities are owned by the consumer, the electrical corporation, or any other party.")

(Continued)

IX. Fixed Recovery Charge (Cont'd)

3. ISSUANCE ADVICE LETTER:

PG&E shall submit an Issuance Advice Letter no later than one business day after each series of Recovery Bonds is priced. The Issuance Advice Letter will include the final issuance details and a request that the Fixed Recovery Charge be set based on the actual amount, price, and other terms of that series of Recovery Bonds. Unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter based on the arithmetic accuracy of the calculations or compliance with (i) Article 5.8, (ii) the Financing Order or (iii) the requirements of the Issuance Advice Letter (including the attached Finance Team approval letter), the Fixed Recovery Charges established by the Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing and the Recovery Property, established pursuant to Section 850.1(h) and the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE.

4. FIXED RECOVERY CHARGE ADJUSTMENTS:

PG&E will submit a Routine True-Up Mechanism Advice Letter at least annually, or more often if necessary, as described in the Financing Order to adjust the Fixed Recovery Charge to ensure timely recovery of Recovery Bond principal, interest, and other Financing Costs. All true-up adjustments to the Fixed Recovery Charges shall ensure that the Fixed Recovery Charges generate sufficient revenues to timely pay all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest, and other recovery costs to be paid with Fixed Recovery Charge revenues. The adjustment will be based on the following:

(1) the most recent sales forecast; (2) the projected amortization schedule; (3) estimated ongoing financing costs; (4) an adjustment to reflect collections from the prior period; and (5) changes to projected uncollectibles. The advice letter will adjust the Fixed Recovery Charge for each series of Fixed Recovery Bonds issued and become effective on 1) March 1, in the case of an annual Routine True-Up, 2) September 1, in the case of a semi-annual Routine True-Up, and 3) the first day of the month that is at least 50 days after the submission of an interim Routine True-Up.

In addition to the Routine True-Up Mechanism, PG&E may also make changes to the Fixed Recovery Charge based on changes to the logic, structure, and components of the cash flow model not specified above. In this case, PG&E will submit a Non-Routine True-Up Mechanism Advice Letter at least 90 days before the date when the proposed changes would become effective.

(L)

(L)

(Continued)

**ELECTRIC PRELIMINARY STATEMENT PART IX** Sheet 3
FIXED RECOVERY CHARGE

IX. Fixed Recovery Charge (Cont'd)

5. FIXED RECOVERY CHARGE[2] (cents/kWh): (T)/(L)

FIXED RECOVERY BOND Series 1……………………………………………………0.548 (L)



[2] Displayed as Recovery Bond Charge on Consumers' bills. (N)

(Continued)

Advice 6579-E

# Exhibit 5

## Pre-Issuance Approval Letter Of The Finance Team

STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

May 3, 2022 **VIA ELECTRONIC MAIL**

Margaret K. Becker
Vice President and Treasurer
Pacific Gas and Electric Company
Mail Code B12H
77 Beale Street
San Francisco, CA 94105
mari.becker@pge.com

**Subject: Pre-Issuance Approval Letter for PG&E Senior Secured Recovery Bonds Series 2022-A, Tranches A-1 through A-5 (Recovery Bonds)**

Dear Ms. Becker,

Pursuant to Ordering Paragraph 4 of California Public Utilities Commission (the "Commission") Decision (D.) 21-05-015 (the "Decision"), the Commission Finance Team (consisting of Pete Skala, Interim Deputy Executive Director for Energy and Climate Policy and Interim Director of Energy Division, Christine Jun Hammond, General Counsel, and their designated representatives) provides this letter evidencing the Finance Team's pre-issuance review and approval of Pacific Gas and Electric Company's ("PG&E") issuance of Recovery Bonds authorized by the Decision, the terms of which are set forth in the Draft Issuance Advice Letter for the Senior Secured Recovery Bonds Series 2022-A, Tranches A-1 through A-5 attached hereto as Exhibit A (the "Draft Issuance Advice Letter"). As set forth below, the Finance Team confirms it has completed its pre-issuance review of and approves the material terms of the Recovery Bonds as presented in the Draft Issuance Advice Letter.

In accordance with the Decision, the final terms and structure of the Recovery Bonds, including the recovery of the Bond Issuance Costs and all ongoing financing costs for the life of the Recovery Bonds, as well as the initial fixed recovery charges, are to be approved through the Issuance Advice Letter process as provided in the Decision.

## FINANCE TEAM REVIEW AND APPROVAL

### I. COMMISSION AUTHORITY FOR APPROVING STRUCTURE AND TERMS FOR RECOVERY BONDS

On January 6, 2021, PG&E filed an application under California Public Utilities Code Section 850 et seq.[1] seeking the Commission's approval of a proposed financing order for PG&E's

[1] On July 12, 2019, Governor Newsom signed into law Assembly Bill (AB) No. 1054, which amended Division 1, Part 1, Chapter 4, Article 5.8, commencing with § 850 of the Public Utilities Code. Public

issuance of Recovery Bonds to fund costs and expenses related to 2017 North Bay Wildfires. Specifically, PG&E requested authority to issue Recovery Bonds for $7.5 Billion, including Financing Costs associated with issuing the Recovery Bonds.

The Commission reviewed PG&E's request, considered comments filed by stakeholders who were parties to the proceeding (A.21-01-004), issued a financing order, and granted PG&E's request to allow PG&E to submit an Issuance Advice Letter when final terms and structure for the Recovery Bonds have been established.[2] The Issuance Advice Letter is to include the critical details and final terms of the proposed Recovery Bonds and sets forth the cost allocation and rate design methodology and Fixed Recovery Charge cash flow formula authorized by the Commission to establish initial Fixed Recovery Charges for a series of Recovery Bonds.

## II. ESTABLISHMENT OF A FINANCE TEAM

The Decision provides for, among other tools, "employing the review and approval of the Finance Team … should reduce, to the maximum extent possible, the rates to Consumers on a present value basis,"[3] which is consistent with the statutory mandate that "[t]he recovery of recovery costs through the designation of the fixed recovery charges and any associated fixed recovery tax amounts, and the issuance of recovery bonds in connection with the fixed recovery charges, would reduce, to the maximum extent possible, the rates on a present value basis that consumers within the electrical corporation's service territory would pay as compared to the use of traditional utility financing mechanisms, which shall be calculated using the electrical corporation's corporate debt and equity in the ratio approved by the Commission at the time of the financing order."[4] We refer to this statutory mandate as the "Savings Standard".

Ordering Paragraphs 2 and 4 of the Decision provide that:

> The purpose of the Finance Team is to provide oversight over the structuring, marketing, and pricing of each Recovery Bond transaction and to review and approve the material terms of such transaction in light of the goal to reduce rates on a present value basis to the maximum extent possible pursuant to Assembly Bill 1054's directives.
>
> The Finance Team's pre-issuance review and approval of the material terms and structure of a series of Recovery Bonds will be evidenced by a letter from the Finance Team to Pacific Gas and Electric Company (PG&E) delivered on or before the date of the pricing of the relevant Recovery Bonds. PG&E shall also be required to include such letter as an attachment to the Issuance Advice Letter relating to such series of Recovery Bonds. Such approval letter shall be a condition precedent to the issuance of such series of Recovery Bonds.

Utilities Code Article 5.8 was later amended by AB 1513 and AB 913 and authorizes the issuance of Recovery Bonds.

[2] Decision Ordering ¶ 17.

[3] Decision Conclusion of Law ¶ 6.

[4] Public Utilities Code § 850.1(a)(1)(A)(ii)(III).

Consistent with the Decision, the Commission established a Finance Team consisting of the Commission's Interim Director of Energy Division, Pete Skala (who also serves as the Deputy Executive Director for Energy and Climate Policy), the Commission's General Counsel, Christine Jun Hammond, and additional designated representatives from Commission staff. The Finance Team also included Ducera Partners LLC, as Financial Advisor, and Paul, Weiss, Rifkind, Wharton & Garrison LLP, as Legal Advisor.

## III. PG&E's ACTIVITIES

In accordance with the Financing Order, PG&E undertook a number of activities in arranging for the issuance of the Recovery Bonds. In addition to the specific activities discussed in the following section, PG&E has represented that it has undertaken the following activities:

- Responded to all Finance Team inquiries and comments and incorporated Finance Team input.
- Registered the Recovery Bonds with the Securities and Exchange Commission (SEC) to facilitate greater liquidity and marketed the Recovery Bonds to ABS and corporate bond investors.
- Solicited advice from the underwriters on the number of rating agencies to apply with, selected two agencies with the benefit of such advice, and applied for and received preliminary Aaa(sf)/AAA(sf) ratings from two of the major rating agencies with final Aaa(sf)/AAA(sf) ratings as a condition of closing.
- Evaluated market conditions in consultation with the underwriters, including treasury market volatility and spread expansion, if any timing modifications would be appropriate and determined when to go to market to achieve the Savings Standard.
- In conjunction with the underwriters' advice, developed and implemented a marketing plan to maximize investor interest and pricing opportunities.
- Provided preliminary prospectus to prospective investors.
- Allowed sufficient time for investors to review the preliminary prospectus and to ask questions regarding the transaction.
- Arranged for the issuance of rating agency pre-sale reports during the marketing period.
- During the period that the Recovery Bonds were marketed, PG&E held daily market update discussions with the underwriting team and the Finance Team's financial advisors to review relevant pricing benchmarks, discuss market conditions and develop strategies for pricing.
- Had multiple conversations with members of the underwriting team and the Finance Team's financial advisors before and during the marketing phase in which PG&E identified the existence of the Savings Standard.

- Conducted a "Test the Waters" presentation with the underwriters to focus prospective investors on PG&E's contemplated Recovery Bond offering and solicit feedback ahead of the offering.
- Conducted roadshow meetings with investors to provide information on the offering.
- Directed the underwriters to provide potential investors with access to an internet roadshow for viewing at investors' convenience.
- Adapted the Recovery Bond offering to market conditions and investor demand at the time of pricing. Variables impacting the final structure of the transaction were evaluated including the tranche structure, term, length of weighted average lives, issuance size, amortization schedules, credit protections and maturity of the Recovery Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order.
- Independently reviewed opportunities to achieve the best pricing, consistent with the Savings Standard, at the time of issuance taking into account the marketing process to date, level of subscription, market benchmarks, SB901 testimony benchmarks, passive underwriter feedback and advice of underwriters on steps necessary to achieve the best pricing.
- With consideration to input from and the approval of the Finance Team and underwriters (and each of their respective counsels), finalized documentation in accordance with established standards for transactions of this sort and the terms of the Financing Order.

## IV. FINANCE TEAM REVIEW

The Finance Team met periodically with PG&E representatives, via teleconference, from March 2022 through May 2022, to address subjects such as: (1) the underwriter and syndication group size, selection process, participants, allocations, and economics, which involved a Request for Proposal (RFP) process, obtaining a broad view of transaction structure alternatives from potential underwriters and proposals from a broad set of banks; (2) the structure of the Recovery Bonds, including considerations reviewed or proposed during the RFP process and recommendations from PG&E and its lead underwriter, including on parameters to drive the greatest level of investor interest and resulting savings to ratepayers; (3) the Recovery Bonds' credit rating agency materials, supporting materials and preliminary AAA/Aaa results; (4) the underwriters' preparation, proposed marketing, marketing materials, and proposed syndication of the Recovery Bonds; (5) the proposed pricing approach of the Recovery Bonds and certifications to be provided by PG&E and the lead underwriter (with ongoing review and involvement in the pricing process); (6) all associated Recovery Bond costs (including Bond Issuance Costs and other Financing Costs), servicing and administrative fees and associated crediting as well as a comparison of such costs relative to other issuances, (7) maturities, weighted average lives and alternative structures, (8) reporting templates, (9) the amount of PG&E's equity contribution to the related SPE, (10) overcollateralization and other credit enhancements and (11) the initial calculation of the related Fixed Recovery Charges. The

Finance Team also met both with PG&E and without PG&E to evaluate PG&E's proposals and to conduct due diligence, including reviewing the validity of PG&E's assumptions, evaluating potential modifications, and developing recommended paths forward. In accordance with the Decision, the Finance Team's review included the following:

### 1. Recovery Bonds Structure

Pursuant to the Decision, the Finance Team was provided the right to review all material terms of the Recovery Bonds and other items the Finance Team determined were appropriate to perform its reviewing role.[5] With the benefit of preliminary structures proposed by potential underwriters in the RFP process, the Finance Team considered and made inquiries about PG&E's proposed structure, proposed structuring parameters and proposed alternatives. The Finance Team discussed parameters to maximize potential net present value savings and available transaction alternatives and provided comments and input, which were evaluated and incorporated into the Recovery Bond structure. After conducting its review, the Finance Team accepted the proposed transaction structure, including five tranches of Recovery Bonds and structural elements designed to appeal to the broadest range of investors possible. The proposed transaction was found to be appropriate subject to modification, if required, as part of the marketing process, to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the rates that would be paid using traditional utility financing mechanisms.

### 2. Recovery Bonds Lead Advisor and Underwriters

Pursuant to the Decision, the Finance Team was provided the right to oversee the process of selecting underwriters for the Recovery Bonds.[6] Accordingly, the Finance Team engaged in several meetings with PG&E to inquire about PG&E's request for proposals, the content of such requests for proposals which could be informative to the broader process, the responses provided, and the selection criteria for underwriters.

Due to the large size of the issuance of Recovery Bonds in the rate reduction bond securitization market, and given the specific conditions that applied at the time of issuance, the Finance Team engaged in discussions with PG&E on its proposal to engage several passive bookrunners. Upon Finance Team request for further information, PG&E represented that the passive bookrunners were necessary for the purpose of providing strategic insights to broaden the scope of marketing the Recovery Bonds and being positioned to provide liquidity in the secondary market. Over several discussions with the Finance Team, PG&E considered the unique circumstances surrounding this transaction, including the need to have additional liquidity based on the transaction's size and the potential to foster a robust secondary market and in consideration that the large size of this transaction could be seen as comparable to transactions in other sectors which utilize passive bookrunners. The Finance Team stressed that PG&E's use of passive bookrunners, even at reduced numbers and economic allocations following Finance Team review, is unique to this transaction and would only be taken with the understanding that it is likely not an appropriate approach for other recovery bond issuances.

[5] Decision, Ordering ¶ 3.

[6] Decision, Ordering ¶ 3.

The underwriter group was expanded to include five diverse bank co-managers to supplement the underwriter group's experience and to include experience with transactions marketed to both ABS and corporate investors. At the Finance Team's recommendation, PG&E increased allocations to diverse banks and named the lead left underwriter as the DE&I Coordinator and tasked it with a coordinating role among the co-managers. The Finance Team further recommended, and PG&E requested, that the lead left underwriter solicit feedback from the co-managers on best practices to facilitate and coordinate efforts such as to maximize their opportunity to participate in the bond issuance transaction.

The Finance Team assessed all materials provided to the Finance Team as part of PG&E's underwriter RFP processes, which included underwriter views on Recovery Bond structures and key components thereof; proposed investor lists; the proposed cost structure; proposed underwriting fees; and views on sizing and pricing to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms. Based on information provided by PG&E, the Finance Team accepted the selection of underwriters noting their relevant experience and execution expertise and the criteria used by PG&E to evaluate underwriters. Underwriter economics were reviewed with PG&E, including review of comparable issuances and the role and scope of this process.

### 3. Credit Rating Agency Review

Pursuant to the Decision, the Finance Team was directed to review the credit rating agency materials associated with the Recovery Bonds.[7] PG&E provided the Finance Team with access to information provided to the rating agencies, including previewing information with the Finance Team. All aspects of the process, including confidential materials shared with the rating agencies were also made available to the Finance Team.

The Finance Team reviewed the credit rating process, related materials, call recordings, and the approach to presentations and the application for credit ratings. With the Finance Team's input on certain information shared with credit ratings, PG&E applied for and received preliminary "triple A" ratings from two of the major rating agencies with final Aaa(sf)(Moody's)/ AAA(sf)(S&P) ratings expected to be confirmed at closing.

### 4. Preparation and Marketing of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review the underwriters' preparation, marketing and syndication of the proposed Recovery Bonds, including indicative pricing.[8] The Finance Team also had the right to review the marketing approach for the Recovery Bonds.[9]

In meetings with PG&E, the Finance Team explored the risks and benefits of the proposed marketing plan for the Recovery Bonds. PG&E and its structuring advisor presented the proposed structure to the Finance Team and its proposal to market to a broad range of ABS and

[7] Decision, Ordering ¶ 3.

[8] Decision, Ordering ¶ 3.

[9] Decision, Ordering ¶ 3.

corporate investors. The Finance Team actively followed, and commented on, the evaluation of potential structures, including requesting the review of and evaluating alternative structures, focusing on maximizing investor participation to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms.

The Finance Team considered input from PG&E and its underwriters on market conditions and expectations as well as investor demand to assist in determining the suitable timing to go to market and the final size and structure of the offering. PG&E and its lead underwriters provided the Finance Team with assessments on market timing, sizing and structure based on key indicators such as, market conditions and expectations, changes in benchmark rates and spreads for comparable issuances, the potential for other transactions to compete with the issuance of this series of Recovery Bonds and the potential implication on future series of recovery bonds.

After evaluation of a broad range of potential alternatives, PG&E ultimately selected, with the Finance Team's concurrence, a proposed structure that was anticipated to produce the greatest amount of investor interest, highest present value savings and lowest weighted average interest rate on the Recovery Bonds relative to alternative structures. Having conducted its review and provided input and comments on the proposed structuring and marketing of the Recovery Bonds, the Finance Team accepted the approach to register the Recovery Bonds with the Securities and Exchange Commission on a Form SF-1 to facilitate greater liquidity and identify the Recovery Bonds as not "asset-backed securities" as such term is defined by the SEC in governing regulations Item 1101 of Regulation AB.

With the opportunity to provide comment by the Finance Team, PG&E developed and implemented a marketing and structuring plan to incentivize underwriters to market the Recovery Bonds to their customers and to reach out to a broad base of potential investors, including both corporate and ABS investors and investors who have not previously purchased this type of security. PG&E informed prospective investors early about securitization through "test the waters" presentations and roadshows and the underwriters agreed to use all forms of marketing available to them to distribute the offering, including educating their sales force and providing potential investors with access to a broad investor call, one-on-one and small group investor calls.

Pursuant to the Decision, the Finance Team reviewed and provided input on certificates provided by PG&E and the lead left underwriter, necessary to further align interests and ensure the statutory objective was achieved.[10]

The Finance Team was apprised that PG&E held frequent market update discussions with the underwriting team to develop recommendations for pricing. PG&E and the Finance Team met with the underwriting team before and during the marketing phase. The Finance Team's Financial Advisor engaged with the underwriters on key elements of the marketing, pricing, and syndication process including participating in market updates, pricing discussions, and the "test the waters" presentations and roadshows, using such information to inform the Finance Team's

[10] Decision, Ordering ¶ 3.

review and feedback on the structure and marketing process. This process included participating in pricing discussions, review of subscriptions, and modifications available, focused on meeting the statutory objective.

### 5. Transaction Fees and Costs

Pursuant to the Decision, the Finance Team had the right to review all transaction fees and costs for the Recovery Bonds, including Bond Issuance Costs and other Financing Costs.[11] That includes reviewing and approving servicing and administrative fees and associated crediting, and any return on equity contribution.[12]

The Finance Team asked questions and provided input on the fees and costs for the Recovery Bonds, including a review of pricing comparisons and amounts separately credited back by PG&E. The Finance Team provided feedback on various aspects of the fees and costs for the Recovery Bonds. As determined in the Financing Order, the transaction also included a credit enhancement for the Recovery Bonds in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount of the Recovery Bonds. The rate of return on this amount, tied to the cost of the securitization, was also determined in the Financing Order, and reviewed by the Finance Team.

### 6. Collateral and Credit Enhancements

Pursuant to the Decision, the Finance Team was directed to determine whether over-collateralization and other additional credit enhancements would be required for the transaction.[13] In response to the Finance Team's inquiries and input, PG&E confirmed no additional enhancements would be required to obtain the highest possible credit rating and achieve the statutory objective.

### 7. Sale of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review all material terms of the Recovery Bonds in a negotiated offering through one or more underwriters.[14] The Finance Team worked with PG&E and the underwriters (and each of their respective counsels) to finalize documentation in accordance with established standards for transactions of this sort and the terms of the Decision. The Finance Team was apprised of developments in the marketing process, including the "test-the-waters" and roadshow process and results, the level of interest from investors, questions raised throughout the process and pricing implications.

## V. CONCLUSION

The Finance Team has completed its pre-issuance review and approves the material terms of the Recovery Bonds in the Draft Issuance Advice Letter in accordance with the Decision (pending review of ultimately proposed final sizing and pricing levels). Based on the materials that the Finance Team has received and reviewed, the Finance Team is satisfied that the issuance of the

[11] Decision, Ordering ¶ 3.

[12] Decision, Ordering ¶ 3.

[13] Decision, Ordering ¶ 3.

[14] Decision, Ordering ¶ 3.

Recovery Bonds as proposed would reduce, to the maximum extent possible, consumer rates on a present value basis as compared to the use of traditional utility financing mechanisms.

| | |
|---|---|
| *Christine Jun Hammond* | *Pete Skala* |
| Christine Jun Hammond<br>General Counsel | Pete Skala<br>Interim Deputy Executive Director for Energy & Climate Policy, Interim Director of Energy Division |

# EXHIBIT A

# Draft Issuance Advice Letter

**DRAFT**

Month XX, 2022

**Advice 6XXX-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject: Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 21-05-015 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Recovery Bonds, the initial Fixed Recovery Charge for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series [2022-A], Tranche(s) [●], [●], [●], [●] and [●] ("Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 54 is the Finance Team's pre-issuance approval letter dated [Pricing Date], 2022.

## Purpose

This submission establishes initial Fixed Recovery Charge for rate schedules for Consumers, including the Billing Commencement Date. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"). Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Bond Issuance Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In D. 21-05-015, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the bond sizing methodology and Fixed Recovery Charge formulas found reasonable by the Commission in D. 21-05-015 to establish initial Fixed Recovery Charge for a series of Recovery Bonds. Using the methodology approved by the Commission in D. 21-05-015, this submission establishes the initial Fixed Recovery Charge.

## Issuance Information:

**DRAFT**

Decision 21-05-015 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series [2022-A]
Recovery Property Owner (SPE): PG&E Wildfire Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: [May 9], 2022
Bond Rating(s): [AAA(sf) (S&P) / Aaa(sf) (Moody's)]
Principal Amount Issued: $[$3,000,000,000]
Bond Issuance Costs: $[18,053,179] (See Table 1 below)
Bond Issuance Costs as a Percent of Principal Amount Issued: [0.6]%
Recovery Costs Financed: $[●]
Coupon Rate(s): [●]% (Tranche [●]); [●]% (Tranche [●]); and [●]% (Tranche [●])
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): [●], 20[●] (Tranche [●]); [●], 20[●] (Tranche [●]); and [●], 20[●] (Tranche [●])
Legal Maturity Date(s): [●], 20[●] (Tranche [●]); [●], 20[●] (Tranche [●]); [●], 20[●] (Tranche [●]); [●], 20[●] (Tranche [●]); and [●], 20[●] (Tranche [●])
Payment Dates (semi-annually): [June 1] and [December 1]
Annual Servicing Fee as a percent of the issuance amount: 0.05%
Overcollateralization amount for the series, if any: None
Principal Amount of Recovery Property Established: $[●]
FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: [June 1, 2022]
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**<u>Bond Issuance Costs:</u>**

| **Table 1<br>Bond Issuance Costs** | |
|---|---|
| Underwriter Fees and Expenses | $[12,000,000 ] |
| Legal Fees and Expenses | [2,396,079] |
| SEC Registration Fees | [278,100] |
| Rating Agency Fees | [1,285,000] |
| Accounting Fees and Expenses | 125,000 |
| Section 1904 Fees[1] | 756,000 |
| Printing/Edgarizing Costs | [150,000] |
| Servicer Set-up Costs | 3,000 |
| Bond Trustee Fees and Expenses | [60,000] |
| Original Issue Discount | [TBD] |
| Company Advisory Fee | 750,000 |

DRAFT

| | |
|---|---|
| Miscellaneous | 250,000 |
| Costs of the Commission | [TBD] |
| **Total** | **$[18,053,179]** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 21-05-015. | |

**True-Up Mechanism:**

Not less often than annually, the servicer will compare the actual principal amortization with the scheduled principal amortization as set forth in Exhibit 1. If the servicer forecasts that Fixed Recovery Charge collections will be insufficient to make all scheduled payments of bond principal, interest, and related costs on a timely basis during the current or next succeeding payment period or to replenish any draws upon the capital subaccount, a change to the Fixed Recovery Charge will be requested via a Routine True-Up Mechanism Advice Letter or Non- Routine True-Up Mechanism Advice Letter in accordance with Decision 21-05-015.

**Ongoing Financing Costs:**

| **Table 2<br>Estimated Ongoing Financing Costs** | | |
|---|---|---|
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $[841,667] | $[750,000] |
| Administration Fee | [70,139] | 62,500 |
| Accountant's Fee | 62,500 | 62,500 |
| Legal Fees/Expenses for PG&E's/Issuer's Counsel | 17,500 | 17,500 |
| Bond Trustee's/ Bond Trustee's Counsel Fees and Expenses | 8,500 | 8,500 |
| Independent Managers' Fees | 1,500 | 1,500 |
| Rating Agency Fees | 20,000 | 20,000 |
| Printing/Edgarizing Fees | 5,000 | 5,000 |
| Miscellaneous | 5,000 | 5,000 |
| Return on Equity | [TBD] | [TBD] |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$[1,031,806]** | **$[932,500]** |

**Fixed Recovery Charge:**

Table 3 below shows the current assumptions for each of the variables used in the Fixed Recovery Charge calculation.

| **Table 3<br>Input Values For Fixed Recovery Charge** | |
|---|---|
| kWh sales for the applicable period | |

| | |
|---|---|
| Percent of revenue requirement allocated to Consumers | |
| Percent of Consumers' revenue written off | |
| Percent of Consumers' billed amounts expected to be uncollected | |
| Percent of billed amounts collected in current month | |
| Percent of billed amounts collected in second month after billing | |
| Percent of billed amounts collected in third month after billing | |
| Percent of billed amounts collected in fourth month after billing | |
| Percent of billed amounts collected in fifth month after billing | |
| Percent of billed amounts collected in sixth month after billing | |
| Ongoing Financing Costs for the applicable period | |
| Expected Fixed Recovery Charge outstanding balance as of__/__/____ | |

Table 4 shows the initial Fixed Recovery Charge calculated for Consumers. The Fixed Recovery Charge calculations are shown in Exhibit 2.

| **Table 4** | |
|---|---|
| Consumers Fixed Recovery Charge[1] | ¢/kWh |

Exhibit 4 includes proposed changes to Part IX of PG&E's Preliminary Statement to show the Fixed Recovery Charge rate value which is to be effective June 1, 2022.[2] Preliminary Statement Part IX is included in this advice letter on an illustrative basis and will be submitted again in PG&E's June rate change advice letter before it is made effective on June 1, 2022.

**Recovery Property:**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charge set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charge set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 3, together with all Ongoing Financing Costs as the same become due.

[1] For residential rates, PG&E shall retain the rate relationships by tier determined by D.15-07-001 with the addition of the Fixed Recovery Charge and Customer Credit.

[2] PG&E has proposed certain text changes to Preliminary Statement Part IX in Advice 6568-E which are pending approval with a requested effective date prior to June 1, 2022. These pending changes are reflected in Exhibit 4.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charge, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charge under the True-Up Mechanism.

These Fixed Recovery Charge, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 3 are paid in full to the owner of the Recovery Property, or its assignee(s).

## Description of Exhibits

Exhibit 1 to this Issuance Advice Letter presents the scheduled principal amortization schedule for the Recovery Bonds.

Exhibit 2 presents the Fixed Recovery Charge calculations.

Exhibit 3 presents the amounts receivable and expected principal amount amortization.

Exhibit 4 provides proposed changes to Part IX of PG&E's Preliminary Statement.

Exhibit 5 provides the pre-issuance approval letter of the Finance Team.

## Effective Date

In accordance with Decision 21-05-015, unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter, the Issuance Advice Letter and the Fixed Recovery Charge established by an Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charge will continue to be effective, unless they are changed by a subsequent True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes.

## Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.21-01-004. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com.

Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Sidney Bob Dietz II
Director, Regulatory Relations

Attachments
Attachment 1: Exhibits 1-5

cc: Service List for A.21-01-004

**Exhibit 1**
**Recovery Bond Terms and Debt Service Schedule**

| Tranche | Expected Weighted Average Life | Principal Amount Offered | Scheduled Final Payment Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|---|
| | | $0 | | | |

**Tranche A-1**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|

# Exhibit 2
# Fixed Recovery Charge Calculation

| (A) | (B) | (C) = (A) / (B) |
|---|---|---|
| Highest Periodic Billing Requirement ($) | Forecasted Billed and Collected Sales for Highest Periodic Requirement (MWh) | Fixed Recovery Charge (¢/kWh)* |
| | | |

*Fixed Recovery Charge applicable to non-CARE and non-FERA consumers

**Exhibit 3**
**Periodic Payment Requirements**

The total amount payable to the owner of the Recovery Property, or its assignee(s), pursuant to this issuance advice letter is a $ principal amount, plus interest on such principal amount, plus other Financing Costs, to be obtained from Fixed Recovery Charges calculated in accordance with D. [ ].

The Fixed Recovery Charges shall be adjusted from time to time, at least annually, via the Routine True-Up Mechanism Advice Letter and Non-Routine True-Up Mechanism Advice Letter in accordance with the Decision.

The following amounts are scheduled to be paid by the Bond Trustee from Fixed Recovery Charges it has received during the two Payment Periods following the Closing Date. These payment amounts include principal plus interest and plus other Ongoing Financing Costs.

| Payment Period | Recovery Bond Payments (See Exhibit 1) | Ongoing Financing Costs (see Table 2) | Periodic Payment Requirement |
|---|---|---|---|
| **First Payment Period** | | | |
| **Second Payment Period** | | | |

IX. Fixed Recovery Charge

1. PURPOSE:

The purpose of this section is to establish a Fixed Recovery Charge, as mandated by Article 5.8, Chapter 4, Part 1, Division 1 of the California Public Utilities Code (Article 5.8). Article 5.8 authorizes PG&E to recover a portion of its costs associated with catastrophic wildfires ignited in 2017 (Catastrophic Wildfire Amounts) through the issuance of Recovery Bonds. The Fixed Recovery Charge is defined by Article 5.8 as a nonbypassable, separate charge that is authorized by the Commission in a Financing Order to recover the Catastrophic Wildfire Amounts and financing costs associated with the Recovery Bonds. The Fixed Recovery Charge will be composed of the following costs: (1) interest and principal on the Recovery Bonds, (2) administration and servicing fees, (3) Bond Trustee fees and other expenses, (4) any credit enhancements, (5) allowance for uncollectibles, (6) replenishing the capital subaccount, (7) authorized rate of return on PG&E's equity contribution to the Special Purpose Entity (SPE), and (8) other financing costs. A separate Fixed Recovery Charge will apply to each series of Recovery Bonds issued. The aggregate amount of applicable Fixed Recovery Charges will appear on customers' bills under one line item called "Recovery Bond Charge (RBC)." (N) | (N)

The rights in and to the Fixed Recovery Charge established pursuant to the Financing Order constitute "recovery property" as defined in the legislation and have been established pursuant to a Financing Order (Decision (D.) 21-05-015) issued by the California Public Utilities Commission.

Concurrently with the effectiveness of the Fixed Recovery Charge, PG&E has sold all of its rights with respect to such recovery property to [(SPE)], a Delaware Limited Liability Company (SPE). The recovery property includes the right, title, and interest of PG&E 1) in and to the Fixed Recovery Charges, including all rights to obtain adjustments to the Fixed Recovery Charges as provided in the Financing Order, and 2) to be paid the amount that is determined in the Financing Order that PG&E is lawfully entitled to receive pursuant to the provisions of Article 5.8 and the proceeds thereof, and all revenues, collections, claims, payments, money, or proceeds of or arising from Fixed Recovery Charges that are subject of the Financing Order. PG&E has no rights to the recovery property, Fixed Recovery Charge or any amounts payable thereunder.

2. APPLICABILITY:

This Fixed Recovery Charge shall apply to all customers[1] except for those customers participating in the California Alternate Rates for Energy or Family Electric Rate Assistance programs pursuant to Section 850.1(i).

---

[1] References to "customer" include the term "consumer" as defined in Section 850(b)(3) and as used in Section 850.1(b). *See* Pub. Util. Code § 850(b)(3) ("'Consumer' means any individual, governmental body, trust, business entity, or nonprofit organization that consumes electricity that has been transmitted or distributed by means of electric transmission or distribution facilities, whether those electric transmission or distribution facilities are owned by the consumer, the electrical corporation, or any other party.")

IX. Fixed Recovery Charge (Cont'd)

3. ISSUANCE ADVICE LETTER:

PG&E shall submit an Issuance Advice Letter no later than one business day after each series of Recovery Bonds is priced. The Issuance Advice Letter will include the final issuance details and a request that the Fixed Recovery Charge be set based on the actual amount, price, and other terms of that series of Recovery Bonds. Unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter based on the arithmetic accuracy of the calculations or compliance with (i) Article 5.8, (ii) the Financing Order or (iii) the requirements of the Issuance Advice Letter (including the attached Finance Team approval letter), the Fixed Recovery Charges established by the Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing and the Recovery Property, established pursuant to Section 850.1(h) and the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE.

4. FIXED RECOVERY CHARGE ADJUSTMENTS:

PG&E will submit a Routine True-Up Mechanism Advice Letter at least annually, or more often if necessary, as described in the Financing Order to adjust the Fixed Recovery Charge to ensure timely recovery of Recovery Bond principal, interest, and other Financing Costs. All true-up adjustments to the Fixed Recovery Charges shall ensure that the Fixed Recovery Charges generate sufficient revenues to timely pay all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest, and other recovery costs to be paid with Fixed Recovery Charge revenues. The adjustment will be based on the following:

(1) the most recent sales forecast; (2) the projected amortization schedule; (3) estimated ongoing financing costs; (4) an adjustment to reflect collections from the prior period; and (5) changes to projected uncollectibles. The advice letter will adjust the Fixed Recovery Charge for each series of Fixed Recovery Bonds issued and become effective on 1) March 1, in the case of an annual Routine True-Up, 2) September 1, in the case of a semi-annual Routine True-Up, and 3) the first day of the month that is at least 50 days after the submission of an interim Routine True-Up.

In addition to the Routine True-Up Mechanism, PG&E may also make changes to the Fixed Recovery Charge based on changes to the logic, structure, and components of the cash flow model not specified above. In this case, PG&E will submit a Non-Routine True-Up Mechanism Advice Letter at least 90 days before the date when the proposed changes would become effective.

(L)

(L)

**DRAFT**

IX. Fixed Recovery Charge (Cont'd)

5. FIXED RECOVERY CHARGE[2] (cents/kWh): (T)/(L)

FIXED RECOVERY BOND Series 1……………………………………………………XXXX (L)

---

[2] Displayed as Recovery Bond Charge on Consumers' bills. (N)

**PG&E Gas and Electric**
**Advice Submittal List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Uplight
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

July 14, 2022

**Advice 6649-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject: Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 21-05-015 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Recovery Bonds, the initial Fixed Recovery Charge for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series 2022-B, Tranche(s) A-1, A-2, A-3, A-4 and A-5 ("Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 5 is the Finance Team's pre-issuance approval letter dated July 13, 2022.

## Purpose

This submission establishes initial Fixed Recovery Charge for rate schedules for Consumers, including the Billing Commencement Date. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"). Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Bond Issuance Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In D. 21-05-015, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the bond sizing methodology and Fixed Recovery Charge formulas found reasonable by the Commission in D. 21-05-015 to establish initial Fixed Recovery Charge for a series of Recovery Bonds. Using the

methodology approved by the Commission in D. 21-05-015, this submission establishes the initial Fixed Recovery Charge.

**Issuance Information:**

Decision 21-05-015 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2022-B
Recovery Property Owner (SPE): PG&E Wildfire Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: July 20, 2022
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued: $3,900,000,0000
Bond Issuance Costs: $19,483,463 (See Table 1 below)
Bond Issuance Costs as a Percent of Principal Amount Issued: 0.50%
Recovery Costs Financed: $3,880,516,536
Coupon Rate(s): 4.022% (Tranche A-1); 4.722% (Tranche A-2); 5.081% (Tranche A-3); 5.212% (Tranche A-4); and 5.099% (Tranche A-5)
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): June 1, 2031 (Tranche A-1); June 1, 2037 (Tranche A-2); June 1, 2041 (Tranche A-3); December 1, 2047 (Tranche A-4); and June 1, 2052 (Tranche A-5)
Legal Maturity Date(s): June 1, 2033 (Tranche A-1); June 1, 2039 (Tranche A-2); June 1, 2043 (Tranche A-3); December 1, 2049 (Tranche A-4); and June 1, 2054 (Tranche A-5)
Payment Dates (semi-annually): June 1 and December 1
Annual Servicing Fee as a percent of the issuance amount: .05%
Overcollateralization amount for the series, if any: None
Principal Amount of Recovery Property Established: $3,880,516,536
FRC Annual Adjustment Date: March 1
Semi-Annual Adjustment Dates: September 1

Billing Commencement Date: September 1, 2022
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**Bond Issuance Costs:**

| Table 1<br>Bond Issuance Costs | |
|---|---|
| Underwriter Fees and Expenses | $15,600,000 |
| Legal Fees and Expenses | 808,200 |
| SEC Registration Fees | 361,530 |
| Rating Agency Fees | 1,285,000 |
| Accounting Fees and Expenses | 125,000 |
| Section 1904 Fees[1] | - |
| Printing/Edgarizing Costs | 150,000 |
| Servicer Set-up Costs | - |
| Bond Trustee Fees and Expenses | 60,000 |
| Original Issue Discount | 192,140 |
| Company Advisory Fee | - |
| Miscellaneous | 250,000 |
| Costs of the Commission | 651,593 |
| **Total** | **$19,483,463** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 21-05-015. | |

**True-Up Mechanism:**

Not less often than annually, the servicer will compare the actual principal amortization with the scheduled principal amortization as set forth in Exhibit 1. If the servicer forecasts that Fixed Recovery Charge collections will be insufficient to make all scheduled payments of bond principal, interest, and related costs on a timely basis during the current or next succeeding payment period or to replenish any draws upon the capital subaccount, a change to the Fixed Recovery Charge will be requested via a Routine True-Up Mechanism Advice Letter or Non-Routine True-Up Mechanism Advice Letter in accordance with Decision 21-05-015.

**Ongoing Financing Costs:**

| Table 2<br>Estimated Ongoing Financing Costs[1] | | |
|---|---|---|
| | First Payment Period | Second Payment Period |
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $1,684,583 | $975,000 |
| Administration Fee | 86,389 | 50,000 |
| Accountant's Fee | 31,250 | 31,250 |
| Legal Fees/Expenses for PG&E's/Issuer's Counsel | 8,750 | 8,750 |
| Bond Trustee's/ Bond Trustee's Counsel Fees and Expenses | 8,500 | 8,500 |
| Independent Managers' Fees | 750 | 750 |
| Rating Agency Fees | 20,000 | 20,000 |
| Printing/Edgarizing Fees | 2,500 | 2,500 |
| Miscellaneous | 5,000 | 5,000 |
| Return on Equity | 851,490 | 492,824 |
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$2,699,212** | **$1,594,574** |
| **Note 1:** Certain estimated ongoing financing costs represented above are an allocable share of the overall costs applicable to the Recovery Bonds subject to this Issuance Advice Letter and the Senior Secured Recovery Bonds, Series 2022-A subject to the Issuance Advice Letter dated Mary 4, 2022 (Advice 6579-E). | | |

**Fixed Recovery Charge:**

Table 3 below shows the current assumptions for each of the variables used in the Fixed Recovery Charge calculation.

| Table 3<br>Input Values For Fixed Recovery Charge[1] | |
|---|---|
| kWh sales for the applicable period | 82,119,905,750 |
| Percent of revenue requirement allocated to Consumers | 100% |
| Percent of Consumers' revenue written off (Res/Non-Res) | 0.42%/0.08% |
| Percent of Consumers' billed amounts expected to be uncollected | 0.34% |
| Percent of billed amounts collected in current month | 33.68% |
| Percent of billed amounts collected in second month after billing | 55.43% |
| Percent of billed amounts collected in third month after billing | 7.35% |
| Percent of billed amounts collected in fourth month after billing | 1.72% |
| Percent of billed amounts collected in fifth month after billing | 0.89% |
| Percent of billed amounts collected in sixth month after billing | 0.59% |
| Ongoing Financing Costs for the applicable period | See Table 2 |
| Expected Fixed Recovery Charge outstanding balance as of 7/13/2022 | See Exhibit 3 |

Table 4 shows the initial Fixed Recovery Charge calculated for Consumers. The Fixed Recovery Charge calculations are shown in Exhibit 2.

| Table 4 | |
|---|---|
| Consumers Fixed Recovery Charge[2] | ¢0.564/kWh |

Exhibit 4 includes proposed changes to Part IX of PG&E's Preliminary Statement to show the Fixed Recovery Charge rate value which is to be effective September 1, 2022. Preliminary Statement Part IX is included in this advice letter on an illustrative basis and will be submitted again in PG&E's September rate change advice letter before it is made effective on September 1, 2022.

[1] Applicable period from September 1, 2022 through November 30, 2023.
[2] For residential rates, PG&E shall retain the total rate relationships by tier determined by D.15-07-001 with the addition of the Fixed Recovery Charge and Customer Credit.

**Recovery Property:**

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charge set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charge set forth herein, as adjusted from time to time.
(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 3, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charge, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charge under the True-Up Mechanism.

These Fixed Recovery Charge, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 3 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Description of Exhibits**

Exhibit 1 to this Issuance Advice Letter presents the scheduled principal amortization schedule for the Recovery Bonds.

Exhibit 2 presents the Fixed Recovery Charge calculations.

Exhibit 3 presents the amounts receivable and expected principal amount amortization.

Exhibit 4 provides proposed changes to Part IX of PG&E's Preliminary Statement.

Exhibit 5 provides the pre-issuance approval letter of the Finance Team.

**Effective Date**

In accordance with Decision 21-05-015, unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter, the Issuance Advice Letter and the Fixed Recovery Charge established by an Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charge will continue to be effective, unless they are changed by a subsequent

True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.21-01-004. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

**Attachments**

Attachment 1: Exhibits 1-5

Exhibit 1: Scheduled Principal Amortization Schedule for the Recovery Bonds

Exhibit 2: Fixed Recovery Charge Calculation

Exhibit 3: Amounts Receivable and Expected Principal Amount Amortization

Exhibit 4: Proposed Changes to Part IX of PG&E's Preliminary Statement

Exhibit 5: Pre-Issuance Approval Letter of the Finance Team

cc: Service List for A.21-01-004

California Public Utilities Commission

# ADVICE LETTER SUMMARY

## ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39 E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 6649-E

Tier Designation: 1

Subject of AL: Issuance Advice Letter Submission for Recovery Bonds

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.21-05-015

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are **to be sent via email and are** due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

| | |
|---|---|
| California Public Utilities Commission<br>Energy Division Tariff Unit Email:<br>EDTariffUnit@cpuc.ca.gov | Contact Name: Sidney Bob Dietz II, c/o Megan Lawson<br>Title: Director, Regulatory Relations<br>Utility/Entity Name: Pacific Gas and Electric Company<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: PGETariffs@pge.com |
| | Contact Name:<br>Title:<br>Utility/Entity Name:<br><br>Telephone (xxx) xxx-xxxx:<br>Facsimile (xxx) xxx-xxxx:<br>Email: |

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

Advice 6649-E
July 14, 2022

# Attachment 1

## Exhibits 1-5

Advice 6649-E
July 14, 2022

# Exhibit 1

## Scheduled Principal Amortization Schedule for the Recovery Bonds

**Exhibit 1**
**Recovery Bond Terms and Debt Service Schedule**

| Tranche | Expected Weighted Average Life | Principal Amount Offered | Scheduled Final Payment Date | Final Maturity Date | Interest Rate |
|---|---|---|---|---|---|
| A-1 | 4.99 | $613,080,000 | 6/1/2031 | 6/1/2033 | 4.022% |
| A-2 | 12.09 | $600,000,000 | 6/1/2037 | 6/1/2039 | 4.722% |
| A-3 | 16.96 | $500,040,000 | 6/1/2041 | 6/1/2043 | 5.081% |
| A-4 | 22.42 | $1,149,960,000 | 12/1/2047 | 12/1/2049 | 5.212% |
| A-5 | 27.94 | $1,036,920,000 | 6/1/2052 | 6/1/2054 | 5.099% |
| | | $3,900,000,000 | | | |

**Tranche A-1**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 7/20/2022 | $613,080,000 | $0 | $0 | $0 |
| 6/1/2023 | $576,590,692 | $36,489,308 | $21,301,839 | $57,791,147 |
| 12/1/2023 | $545,225,081 | $31,365,611 | $11,595,239 | $42,960,850 |
| 6/1/2024 | $513,188,246 | $32,036,835 | $10,964,476 | $43,001,311 |
| 12/1/2024 | $480,465,823 | $32,722,423 | $10,320,216 | $43,042,639 |
| 6/1/2025 | $447,043,139 | $33,422,684 | $9,662,168 | $43,084,852 |
| 12/1/2025 | $412,905,211 | $34,137,928 | $8,990,038 | $43,127,966 |
| 6/1/2026 | $378,036,730 | $34,868,481 | $8,303,524 | $43,172,005 |
| 12/1/2026 | $342,422,064 | $35,614,666 | $7,602,319 | $43,216,985 |
| 6/1/2027 | $306,045,244 | $36,376,820 | $6,886,108 | $43,262,928 |
| 12/1/2027 | $268,889,961 | $37,155,283 | $6,154,570 | $43,309,853 |
| 6/1/2028 | $230,939,554 | $37,950,407 | $5,407,377 | $43,357,784 |
| 12/1/2028 | $192,177,008 | $38,762,546 | $4,644,194 | $43,406,740 |
| 6/1/2029 | $152,584,944 | $39,592,064 | $3,864,680 | $43,456,744 |
| 12/1/2029 | $112,145,610 | $40,439,334 | $3,068,483 | $43,507,817 |
| 6/1/2030 | $70,840,874 | $41,304,736 | $2,255,248 | $43,559,984 |
| 12/1/2030 | $28,652,217 | $42,188,657 | $1,424,610 | $43,613,267 |
| 6/1/2031 | $0 | $28,652,217 | $576,196 | $29,228,413 |

**Exhibit 1**
**Tranche A-2**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 7/20/2022 | $600,000,000 | $0 | $0 | $0 |
| 6/1/2023 | $600,000,000 | $0 | $24,475,700 | $24,475,700 |
| 12/1/2023 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2024 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2024 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2025 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2025 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2026 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2026 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2027 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2027 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2028 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2028 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2029 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2029 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2030 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 12/1/2030 | $600,000,000 | $0 | $14,166,000 | $14,166,000 |
| 6/1/2031 | $585,560,723 | $14,439,277 | $14,166,000 | $28,605,277 |
| 12/1/2031 | $541,501,586 | $44,059,137 | $13,825,089 | $57,884,226 |
| 6/1/2032 | $496,360,798 | $45,140,788 | $12,784,852 | $57,925,640 |
| 12/1/2032 | $450,111,804 | $46,248,994 | $11,719,078 | $57,968,072 |
| 6/1/2033 | $402,727,397 | $47,384,407 | $10,627,140 | $58,011,547 |
| 12/1/2033 | $354,179,702 | $48,547,695 | $9,508,394 | $58,056,089 |
| 6/1/2034 | $304,440,162 | $49,739,540 | $8,362,183 | $58,101,723 |
| 12/1/2034 | $253,479,516 | $50,960,646 | $7,187,832 | $58,148,478 |
| 6/1/2035 | $201,267,786 | $52,211,730 | $5,984,651 | $58,196,381 |
| 12/1/2035 | $147,774,259 | $53,493,527 | $4,751,932 | $58,245,459 |
| 6/1/2036 | $92,967,465 | $54,806,794 | $3,488,950 | $58,295,744 |
| 12/1/2036 | $36,815,164 | $56,152,301 | $2,194,962 | $58,347,263 |
| 6/1/2037 | $0 | $36,815,164 | $869,206 | $37,684,370 |

**Exhibit 1**
**Tranche A-3**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 7/20/2022 | $500,040,000 | $0 | $0 | $0 |
| 6/1/2023 | $500,040,000 | $0 | $21,948,853 | $21,948,853 |
| 12/1/2023 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2024 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2024 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2025 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2025 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2026 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2026 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2027 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2027 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2028 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2028 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2029 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2029 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2030 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2030 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2031 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2031 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2032 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2032 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2033 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2033 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2034 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2034 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2035 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2035 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2036 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 12/1/2036 | $500,040,000 | $0 | $12,703,516 | $12,703,516 |
| 6/1/2037 | $479,324,324 | $20,715,676 | $12,703,516 | $33,419,192 |
| 12/1/2037 | $420,343,814 | $58,980,510 | $12,177,234 | $71,157,744 |
| 6/1/2038 | $359,809,168 | $60,534,646 | $10,678,835 | $71,213,481 |
| 12/1/2038 | $297,679,433 | $62,129,735 | $9,140,952 | $71,270,687 |
| 6/1/2039 | $233,912,581 | $63,766,852 | $7,562,546 | $71,329,398 |
| 12/1/2039 | $168,465,471 | $65,447,110 | $5,942,549 | $71,389,659 |
| 6/1/2040 | $101,293,830 | $67,171,641 | $4,279,865 | $71,451,506 |
| 12/1/2040 | $32,352,217 | $68,941,613 | $2,573,370 | $71,514,983 |
| 6/1/2041 | $0 | $32,352,217 | $821,908 | $33,174,125 |

**Exhibit 1**
**Tranche A-4**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 7/20/2022 | 1,149,960,000 | 0 | 0 | 0 |
| 6/1/2023 | 1,149,960,000 | 0 | 51,777,971 | 51,777,971 |
| 12/1/2023 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2024 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2024 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2025 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2025 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2026 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2026 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2027 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2027 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2028 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2028 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2029 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2029 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2030 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2030 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2031 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2031 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2032 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2032 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2033 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2033 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2034 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2034 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2035 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2035 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2036 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2036 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2037 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2037 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2038 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2038 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2039 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2039 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2040 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 12/1/2040 | 1,149,960,000 | 0 | 29,967,958 | 29,967,958 |
| 6/1/2041 | 1,111,553,992 | 38,406,008 | 29,967,958 | 68,373,966 |
| 12/1/2041 | 1,038,898,642 | 72,655,350 | 28,967,097 | 101,622,447 |
| 6/1/2042 | 964,267,067 | 74,631,575 | 27,073,699 | 101,705,274 |
| 12/1/2042 | 887,605,514 | 76,661,553 | 25,128,800 | 101,790,353 |
| 6/1/2043 | 808,858,766 | 78,746,748 | 23,131,000 | 101,877,748 |
| 12/1/2043 | 727,970,106 | 80,888,660 | 21,078,859 | 101,967,519 |
| 6/1/2044 | 644,881,275 | 83,088,831 | 18,970,901 | 102,059,732 |
| 12/1/2044 | 559,532,428 | 85,348,847 | 16,805,606 | 102,154,453 |
| 6/1/2045 | 471,862,092 | 87,670,336 | 14,581,415 | 102,251,751 |
| 12/1/2045 | 381,807,123 | 90,054,969 | 12,296,726 | 102,351,695 |
| 6/1/2046 | 289,302,659 | 92,504,464 | 9,949,894 | 102,454,358 |
| 12/1/2046 | 194,282,073 | 95,020,586 | 7,539,227 | 102,559,813 |
| 6/1/2047 | 96,676,928 | 97,605,145 | 5,062,991 | 102,668,136 |
| 12/1/2047 | 0 | 96,676,928 | 2,519,401 | 99,196,329 |

**Exhibit 1**
**Tranche A-5**

| Payment Date | Principal Balance | Principal | Interest | Total Payment |
|---|---|---|---|---|
| 7/20/2022 | 1,036,920,000 | 0 | 0 | 0 |
| 6/1/2023 | 1,036,920,000 | 0 | 45,676,009 | 45,676,009 |
| 12/1/2023 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2024 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2024 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2025 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2025 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2026 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2026 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2027 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2027 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2028 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2028 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2029 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2029 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2030 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2030 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2031 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2031 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2032 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2032 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2033 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2033 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2034 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2034 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2035 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2035 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2036 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2036 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2037 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2037 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2038 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2038 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2039 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2039 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2040 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2040 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2041 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2041 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2042 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2042 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2043 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2043 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2044 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2044 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2045 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2045 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2046 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2046 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 6/1/2047 | 1,036,920,000 | 0 | 26,436,275 | 26,436,275 |
| 12/1/2047 | 1,033,336,922 | 3,583,078 | 26,436,275 | 30,019,353 |
| 6/1/2048 | 930,350,740 | 102,986,182 | 26,344,925 | 129,331,107 |
| 12/1/2048 | 824,589,081 | 105,761,659 | 23,719,292 | 129,480,951 |
| 6/1/2049 | 715,977,144 | 108,611,937 | 21,022,899 | 129,634,836 |
| 12/1/2049 | 604,438,116 | 111,539,028 | 18,253,837 | 129,792,865 |
| 6/1/2050 | 489,893,112 | 114,545,004 | 15,410,150 | 129,955,154 |
| 12/1/2050 | 372,261,119 | 117,631,993 | 12,489,825 | 130,121,818 |
| 6/1/2051 | 251,458,944 | 120,802,175 | 9,490,797 | 130,292,972 |
| 12/1/2051 | 127,401,151 | 124,057,793 | 6,410,946 | 130,468,739 |
| 6/1/2052 | 0 | 127,401,151 | 3,248,092 | 130,649,243 |

Advice 6649-E
July 14, 2022

# Exhibit 2

## Fixed Recovery Charge Calculation

## Exhibit 2
## Fixed Recovery Charge Calculations

| (A) | (B) | (C) |
|---|---|---|
| Highest Periodic Billing Requirement ($) | Forecasted Billed and Collected Sales for Highest Periodic Requirement (MWh) | Fixed Recovery Charge (¢/kWh)[1] |
| 204,368,892 | 36,253,788 | 0.564 |

[1] Fixed Recovery Charge is applicable to non-CARE and non-FERA consumers.

Advice 6649-E
July 14, 2022

# Exhibit 3

## Amounts Receivable and Expected Principal Amount Amortization

**Exhibit 3**
**Periodic Payment Requirements**

The total amount payable to the owner of the Recovery Property, or its assignee(s), pursuant to this issuance advice letter is a $ principal amount, plus interest on such principal amount, plus other Financing Costs, to be obtained from Fixed Recovery Charges calculated in accordance with D. 21-05-015

The Fixed Recovery Charges shall be adjusted from time to time, at least annually, via the Routine True-Up Mechanism Advice Letter and Non-Routine True-Up Mechanism Advice Letter in accordance with the Decision.

The following amounts are scheduled to be paid by the Bond Trustee from Fixed Recovery Charges it has received during the two Payment Periods following the Closing Date. These payment amounts include principal plus interest and plus other Ongoing Financing Costs.

| Payment Period | Recovery Bond Payments (See Exhibit 1) | Ongoing Financing Costs (see Table 2) | Periodic Payment Requirement |
|---|---|---|---|
| **First Payment Period** | $201,669,680.60 | $2,699,211.71 | $204,368,892.31 |
| **Second Payment Period** | $126,234,599.02 | $1,594,573.50 | $127,829,172.52 |

Advice 6649-E
July 14, 2022

# Exhibit 4

## Proposed Changes to Part IX of PG&E's Preliminary Statement

**ELECTRIC PRELIMINARY STATEMENT PART IX** Sheet 1
FIXED RECOVERY CHARGE

IX. Fixed Recovery Charge

1. PURPOSE:

The purpose of this section is to establish a Fixed Recovery Charge, as mandated by Article 5.8, Chapter 4, Part 1, Division 1 of the California Public Utilities Code (Article 5.8). Article 5.8 authorizes PG&E to recover a portion of its costs associated with catastrophic wildfires ignited in 2017 (Catastrophic Wildfire Amounts) through the issuance of Recovery Bonds. The Fixed Recovery Charge is defined by Article 5.8 as a nonbypassable, separate charge that is authorized by the Commission in a Financing Order to recover the Catastrophic Wildfire Amounts and financing costs associated with the Recovery Bonds. The Fixed Recovery Charge will be composed of the following costs: (1) interest and principal on the Recovery Bonds, (2) administration and servicing fees, (3) Bond Trustee fees and other expenses, (4) any credit enhancements, (5) allowance for uncollectibles, (6) replenishing the capital subaccount, (7) authorized rate of return on PG&E's equity contribution to the Special Purpose Entity (SPE), and (8) other financing costs. A separate Fixed Recovery Charge will apply to each series of Recovery Bonds issued. The aggregate amount of applicable Fixed Recovery Charges will appear on customers' bills under one line item called "Recovery Bond Charge (RBC)." (N) I (N)

The rights in and to the Fixed Recovery Charge established pursuant to the Financing Order constitute "recovery property" as defined in the legislation and have been established pursuant to a Financing Order (Decision (D.) 21-05-015) issued by the California Public Utilities Commission.

Concurrently with the effectiveness of the Fixed Recovery Charge, PG&E has sold all of its rights with respect to such recovery property to [(SPE)], a Delaware Limited Liability Company (SPE). The recovery property includes the right, title, and interest of PG&E 1) in and to the Fixed Recovery Charges, including all rights to obtain adjustments to the Fixed Recovery Charges as provided in the Financing Order, and 2) to be paid the amount that is determined in the Financing Order that PG&E is lawfully entitled to receive pursuant to the provisions of Article 5.8 and the proceeds thereof, and all revenues, collections, claims, payments, money, or proceeds of or arising from Fixed Recovery Charges that are subject of the Financing Order. PG&E has no rights to the recovery property, Fixed Recovery Charge or any amounts payable thereunder.

2. APPLICABILITY:

This Fixed Recovery Charge shall apply to all customers[1] except for those customers participating in the California Alternate Rates for Energy or Family Electric Rate Assistance programs pursuant to Section 850.1(i).

[1] References to "customer" include the term "consumer" as defined in Section 850(b)(3) and as used in Section 850.1(b). *See* Pub. Util. Code § 850(b)(3) ("'Consumer' means any individual, governmental body, trust, business entity, or nonprofit organization that consumes electricity that has been transmitted or distributed by means of electric transmission or distribution facilities, whether those electric transmission or distribution facilities are owned by the consumer, the electrical corporation, or any other party.")

(Continued)

**ELECTRIC PRELIMINARY STATEMENT PART IX** Sheet 2
FIXED RECOVERY CHARGE

IX. Fixed Recovery Charge (Cont'd)

3. ISSUANCE ADVICE LETTER:

PG&E shall submit an Issuance Advice Letter no later than one business day after each series of Recovery Bonds is priced. The Issuance Advice Letter will include the final issuance details and a request that the Fixed Recovery Charge be set based on the actual amount, price, and other terms of that series of Recovery Bonds. Unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter based on the arithmetic accuracy of the calculations or compliance with (i) Article 5.8, (ii) the Financing Order or (iii) the requirements of the Issuance Advice Letter (including the attached Finance Team approval letter), the Fixed Recovery Charges established by the Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing and the Recovery Property, established pursuant to Section 850.1(h) and the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE.

4. FIXED RECOVERY CHARGE ADJUSTMENTS:

PG&E will submit a Routine True-Up Mechanism Advice Letter at least annually, or more often if necessary, as described in the Financing Order to adjust the Fixed Recovery Charge to ensure timely recovery of Recovery Bond principal, interest, and other Financing Costs. All true-up adjustments to the Fixed Recovery Charges shall ensure that the Fixed Recovery Charges generate sufficient revenues to timely pay all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest, and other recovery costs to be paid with Fixed Recovery Charge revenues. The adjustment will be based on the following:

(1) the most recent sales forecast; (2) the projected amortization schedule; (3) estimated ongoing financing costs; (4) an adjustment to reflect collections from the prior period; and (5) changes to projected uncollectibles. The advice letter will adjust the Fixed Recovery Charge for each series of Fixed Recovery Bonds issued and become effective on 1) March 1, in the case of an annual Routine True-Up, 2) September 1, in the case of a semi-annual Routine True-Up, and 3) the first day of the month that is at least 50 days after the submission of an interim Routine True-Up.

In addition to the Routine True-Up Mechanism, PG&E may also make changes to the Fixed Recovery Charge based on changes to the logic, structure, and components of the cash flow model not specified above. In this case, PG&E will submit a Non-Routine True-Up Mechanism Advice Letter at least 90 days before the date when the proposed changes would become effective.

(L)

(L)

(Continued)

**ELECTRIC PRELIMINARY STATEMENT PART IX** Sheet 3
FIXED RECOVERY CHARGE

IX. Fixed Recovery Charge (Cont'd)

5. FIXED RECOVERY CHARGE[2] (cents/kWh):

FIXED RECOVERY BOND Series 1……………………………………………0.548

FIXED RECOVERY BOND Series 2……………………………………………0.564 (N)

[2] Displayed as Recovery Bond Charge on Consumers' bills.

(Continued)

Advice 6649-E
July 14, 2022

# Exhibit 5

## Pre-Issuance Approval Letter of the Finance Team

STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

July 13, 2022 **VIA ELECTRONIC MAIL**

Margaret K. Becker
Vice President and Treasurer
Pacific Gas and Electric Company
Mail Code B12H
77 Beale Street
San Francisco, CA 94105
Mari.Becker@pge.com

**Subject: Pre-Issuance Approval Letter for PG&E Senior Secured Recovery Bonds Series 2022-B, Tranches A-1 through A-5 (Recovery Bonds)**

Dear Ms. Becker,

Pursuant to Ordering Paragraph 4 of California Public Utilities Commission (the "Commission") Decision (D.)21-05-015 (the "Decision"), the Commission Finance Team (consisting of Leuwam Tesfai, Deputy Executive Director for Energy and Climate Policy and Christine Jun Hammond, General Counsel, and their designated representatives) provides this letter evidencing the Finance Team's pre-issuance review and approval of Pacific Gas and Electric Company's ("PG&E") issuance of Recovery Bonds authorized by the Decision, the terms of which are set forth in the Draft Issuance Advice Letter for the Senior Secured Recovery Bonds Series 2022-B, Tranches A-1 through A-5 attached hereto as Exhibit A (the "Draft Issuance Advice Letter"). As set forth below, the Finance Team confirms it has completed its pre-issuance review of and approves the material terms of the Recovery Bonds as presented in the Draft Issuance Advice Letter.

In accordance with the Decision, the final terms and structure of the Recovery Bonds, including the recovery of the Bond Issuance Costs and all ongoing financing costs for the life of the Recovery Bonds, as well as the initial fixed recovery charges, are to be approved through the Issuance Advice Letter process as provided in the Decision.

## FINANCE TEAM REVIEW AND APPROVAL

## I. COMMISSION AUTHORITY FOR APPROVING STRUCTURE AND TERMS FOR RECOVERY BONDS

On January 6, 2021, PG&E filed an application under California Public Utilities Code Section 850 et seq.[1] seeking the Commission's approval of a proposed financing order for PG&E's issuance of Recovery Bonds to fund costs and expenses related to 2017 North Bay Wildfires. Specifically, PG&E requested authority to issue Recovery Bonds for $7.5 Billion, including Financing Costs associated with issuing the Recovery Bonds.

The Commission reviewed PG&E's request, considered comments filed by stakeholders who were parties to the proceeding (A.21-01-004), issued a financing order, and granted PG&E's request to allow PG&E to submit an Issuance Advice Letter when final terms and structure for the Recovery Bonds have been established.[2] The Issuance Advice Letter is to include the critical details and final terms of the proposed Recovery Bonds and sets forth the cost allocation and rate design methodology and Fixed Recovery Charge cash flow formula authorized by the Commission to establish initial Fixed Recovery Charges for a series of Recovery Bonds.

On May 10, 2022, PG&E sponsored, and the issuing entity, PG&E Wildfire Recovery Funding LLC, issued, $3,600,000,000 aggregate principal amount of five tranches of Senior Secured Recovery Bonds, Series 2022-A ("Series One"). The Decision authorizes PG&E to issue the remaining $3.9 billion of Recovery Bonds in one or two series.[3]

## II. ESTABLISHMENT OF A FINANCE TEAM

The Decision provides for, among other tools, "employing the review and approval of the Finance Team … should reduce, to the maximum extent possible, the rates to Consumers on a present value basis,"[4] which is consistent with the statutory mandate that "[t]he recovery of recovery costs through the designation of the fixed recovery charges and any associated fixed recovery tax amounts, and the issuance of recovery bonds in connection with the fixed recovery charges, would reduce, to the maximum extent possible, the rates on a present value basis that consumers within the electrical corporation's service territory would pay as compared to the use of traditional utility financing mechanisms, which shall be calculated using the electrical corporation's corporate debt and equity in the ratio approved by the Commission at the time of the financing order."[5] We refer to this statutory mandate as the "Savings Standard".

---

[1] On July 12, 2019, Governor Newsom signed into law Assembly Bill (AB) No. 1054, which amended Division 1, Part 1, Chapter 4, Article 5.8, commencing with § 850 of the Public Utilities Code. Public Utilities Code Article 5.8 was later amended by AB 1513 and AB 913 and authorizes the issuance of Recovery Bonds.

[2] Decision Ordering ¶ 17.

[3] Decision Ordering ¶ 1(ii).

[4] Decision Conclusion of Law ¶ 6.

[5] Public Utilities Code § 850.1(a)(1)(A)(ii)(III).

Ordering Paragraphs 2 and 4 of the Decision provide that:

> The purpose of the Finance Team is to provide oversight over the structuring, marketing, and pricing of each Recovery Bond transaction and to review and approve the material terms of such transaction in light of the goal to reduce rates on a present value basis to the maximum extent possible pursuant to Assembly Bill 1054's directives.
>
> The Finance Team's pre-issuance review and approval of the material terms and structure of a series of Recovery Bonds will be evidenced by a letter from the Finance Team to Pacific Gas and Electric Company (PG&E) delivered on or before the date of the pricing of the relevant Recovery Bonds. PG&E shall also be required to include such letter as an attachment to the Issuance Advice Letter relating to such series of Recovery Bonds. Such approval letter shall be a condition precedent to the issuance of such series of Recovery Bonds.

Relevant to Series 2022-B, the Decision provides: "Each Series of Recovery Bonds will be subject to a separate issuance approval process …."[6] Consistent with the Decision, the Commission established a Finance Team consisting of the Commission's Deputy Executive Director for Energy and Climate Policy, Leuwam Tesfai, the Commission's General Counsel, Christine Jun Hammond, and additional designated representatives from Commission staff. The Finance Team was advised by Ducera Partners LLC, as Financial Advisor, and Paul, Weiss, Rifkind, Wharton & Garrison LLP, as Legal Advisor.

## III. PG&E's ACTIVITIES

In accordance with the Financing Order, PG&E undertook a number of activities in arranging for the issuance of the Recovery Bonds. In addition to the specific activities discussed in the following section, PG&E has represented that it has undertaken the following activities:

- Responded to all Finance Team inquiries and comments and incorporated Finance Team input.
- Registered the Recovery Bonds with the Securities and Exchange Commission (SEC) to facilitate greater liquidity and marketed the Recovery Bonds to ABS and corporate bond investors.
- Solicited advice from the underwriters on the number of rating agencies to apply with, selected two agencies with the benefit of such advice, and applied for and received preliminary Aaa(sf)/AAA(sf) ratings from two of the major rating agencies with final Aaa(sf)/AAA(sf) ratings as a condition of closing.

---

[6] Decision Ordering ¶ 1(ii).

- Evaluated market conditions in consultation with the underwriters, including treasury market volatility and spread expansion, if any timing modifications would be appropriate, appropriate responses to Bloomberg's review of corporate bond index eligibility for utility securitization bonds and current issuer specific considerations and determined when to go to market to achieve the Savings Standard.
- In conjunction with the underwriters' advice, developed and implemented a marketing plan to maximize investor interest and pricing opportunities.
- Provided preliminary prospectus to prospective investors.
- Allowed sufficient time for investors to review the preliminary prospectus and to ask questions regarding the transaction.
- Arranged for the issuance of rating agency pre-sale reports during the marketing period.
- During the period that the Recovery Bonds were marketed, PG&E held daily market update discussions with the underwriting team and the Finance Team's financial advisors to review relevant pricing benchmarks, discuss market conditions and develop strategies for pricing.
- Had multiple conversations with members of the underwriting team and the Finance Team's financial advisors before and during the marketing phase in which PG&E identified the existence of the Savings Standard.
- Conducted roadshow meetings with investors to provide information on the offering.
- Directed the underwriters to provide potential investors with access to an internet roadshow for viewing at investors' convenience.
- Adapted the Recovery Bond offering to market conditions and investor demand at the time of pricing. Variables impacting the final structure of the transaction were evaluated including the tranche structure, term, length of weighted average lives, issuance size, amortization schedules, credit protections and maturity of the Recovery Bonds and interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for AAA ratings, while meeting the requirements of the Financing Order.
- Independently reviewed opportunities to achieve the best pricing, consistent with the Savings Standard, at the time of issuance taking into account the marketing process to date, level of subscription, market benchmarks, SB901 testimony benchmarks, passive

underwriter feedback, and advice of underwriters on steps necessary to achieve the best pricing.

- With consideration to input from, and the approval of, the Finance Team and underwriters (and each of their respective counsels), finalized documentation in accordance with established standards for transactions of this sort and the terms of the Financing Order.

## IV. FINANCE TEAM REVIEW

The Finance Team met periodically with PG&E representatives, via teleconference, from May 2022 through July 2022, to address subjects such as: (1) the underwriter and syndication group size, selection process, participants, allocations, and economics, which involved a Request for Proposal (RFP) process, obtaining a broad view of transaction structure alternatives from potential underwriters and proposals from a broad set of banks; (2) the structure of the Recovery Bonds, including considerations reviewed or proposed during the RFP process and recommendations from PG&E and its lead underwriter, including on parameters to drive the greatest level of investor interest and resulting savings to ratepayers; (3) the Recovery Bonds' credit rating agency materials, supporting materials and preliminary AAA/Aaa results; (4) the underwriters' preparation, proposed marketing, marketing materials, and proposed syndication of the Recovery Bonds; (5) the proposed pricing approach of the Recovery Bonds and certifications to be provided by PG&E and the lead underwriter (with ongoing review and involvement in the pricing process); (6) all associated Recovery Bond costs (including Bond Issuance Costs and other Financing Costs), servicing and administrative fees and associated crediting as well as a comparison of such costs relative to other issuances, (7) maturities, weighted average lives and alternative structures, (8) reporting templates, (9) the amount of PG&E's equity contribution to the related SPE, (10) overcollateralization and other credit enhancements and (11) the initial calculation of the related Fixed Recovery Charges. The Finance Team also met both with PG&E and without PG&E to evaluate PG&E's proposals and to conduct due diligence, including reviewing the validity of PG&E's assumptions, evaluating potential modifications, and developing recommended paths forward. In accordance with the Decision, the Finance Team's review included the following:

### 1. Recovery Bonds Structure

Pursuant to the Decision, the Finance Team was provided the right to review all material terms of the Recovery Bonds and other items the Finance Team determined were appropriate to perform its reviewing role.[7] With the benefit of preliminary structures proposed by potential underwriters in the RFP process and supplemental RFP responses specific to this series, the Finance Team considered and made inquiries about PG&E's proposed structure, proposed structuring parameters and proposed alternatives. The Finance Team discussed parameters to maximize potential net present value savings and available transaction alternatives and provided comments and input, which were evaluated and incorporated into the Recovery Bond structure. After conducting its review, the Finance Team accepted the proposed transaction structure,

---

[7] Decision, Ordering ¶ 3.

including five tranches of Recovery Bonds and structural elements designed to appeal to the broadest range of investors possible. The proposed transaction was found to be appropriate subject to modification, if required, as part of the marketing process, to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the rates that would be paid using traditional utility financing mechanisms.

### 2. Recovery Bonds Lead Advisor and Underwriters

Pursuant to the Decision, the Finance Team was provided the right to oversee the process of selecting underwriters for the Recovery Bonds.[8] Accordingly, the Finance Team engaged in several meetings with PG&E to inquire about PG&E's request for proposals, the content of such requests for proposals which could be informative to the broader process, the responses provided, and the selection criteria for underwriters.

Due to the large size of the issuance of Recovery Bonds in the rate reduction bond securitization market, and given the specific conditions that applied at the time of issuance, the Finance Team engaged in discussions with PG&E on its proposal to engage several passive bookrunners. Similar to Series One, PG&E represented that the passive bookrunners were necessary for the purpose of providing strategic insights to broaden the scope of marketing the Recovery Bonds and being positioned to provide liquidity in the secondary market. Over several discussions with the Finance Team, PG&E considered the unique circumstances surrounding this transaction, including the need to have additional liquidity based on the transaction's size and the potential to foster a robust secondary market and in consideration that the large size of this transaction could be seen as comparable to transactions in other sectors which utilize passive bookrunners. The Finance Team stressed that PG&E's use of passive bookrunners is unique to this transaction and would only be taken with the understanding that it is likely not an appropriate approach for other recovery bond issuances.

The underwriter group was expanded to include five diverse bank co-managers to supplement the underwriter group's experience and to include experience with transactions marketed to both ABS and corporate investors. PG&E named the lead left underwriter as the Diversity, Equity and Inclusion Coordinator and tasked it with a coordinating role among the co-managers. PG&E also requested that the lead left underwriter solicit feedback from the co-managers on best practices to facilitate and coordinate efforts such as to maximize their opportunity to participate in the bond issuance transaction. PG&E used the same allocations to diverse banks as it did in Series One.

The Finance Team assessed all materials provided to the Finance Team as part of PG&E's underwriter RFP processes, which included underwriter views on Recovery Bond structures and key components thereof; proposed investor lists; the proposed cost structure; proposed underwriting fees; and views on sizing and pricing to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms. Based on information provided by PG&E, the Finance Team accepted the selection of underwriters noting their relevant

[8] Decision, Ordering ¶ 3.

experience and execution expertise, including participation in Series One, and the criteria used by PG&E to evaluate underwriters. PG&E conveyed to the Finance Team that a mix of prior and new participants (for both bookrunners and co-managers) would balance institutional knowledge with fresh perspectives on market views. Underwriter economics were reviewed with PG&E, including review of comparable issuances and the role and scope of this process. Additionally, the Finance Team requested that PG&E opine on whether existing underwriter synergies with Series One should result in a reduced underwriter fee, along with what potential impact a reduced fee may have on the issuance; PG&E ultimately recommended that the proposed underwriting fee was appropriate.

### 3. Credit Rating Agency Review

Pursuant to the Decision, the Finance Team was directed to review the credit rating agency materials associated with the Recovery Bonds.[9] PG&E provided the Finance Team with access to information provided to the rating agencies, including previewing information with the Finance Team. All aspects of the process, including confidential materials shared with the rating agencies were also made available to the Finance Team.

The Finance Team reviewed the credit rating process, related materials, call recordings, and the approach to presentations and the application for credit ratings. With the Finance Team's input on certain information shared with credit ratings, PG&E applied for and received preliminary "triple A" ratings from two of the major rating agencies with final Aaa(sf)(Moody's)/ AAA(sf)(S&P) ratings expected to be confirmed at closing.

### 4. Preparation and Marketing of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review the underwriters' preparation, marketing and syndication of the proposed Recovery Bonds, including indicative pricing.[10] The Finance Team also had the right to review the marketing approach for the Recovery Bonds.[11]

In meetings with PG&E, the Finance Team explored the risks and benefits of the proposed marketing plan for the Recovery Bonds. PG&E and its structuring advisor presented the proposed structure to the Finance Team and its proposal to market to a broad range of ABS and corporate investors. The Finance Team actively followed, and commented on, the evaluation of potential structures, including requesting the review of and evaluating alternative structures, focusing on maximizing investor participation to reduce, to the maximum extent possible, the rates on a present value basis that consumers within PG&E's service territory would pay as compared to the use of traditional utility financing mechanisms.

The Finance Team considered input from PG&E and its underwriters on market conditions and expectations as well as investor demand to assist in determining the suitable timing to go to market and the final size and structure of the offering. PG&E and its lead underwriters provided

---

[9] Decision, Ordering ¶ 3.

[10] Decision, Ordering ¶ 3.

[11] Decision, Ordering ¶ 3.

the Finance Team with assessments on market timing, sizing and structure based on key indicators such as, market conditions and expectations, changes in benchmark rates and spreads for comparable issuances, the potential for other transactions to compete with the issuance of this series of Recovery Bonds and the potential implication on future series of recovery bonds.

After evaluation of a broad range of potential alternatives, PG&E ultimately selected, with the Finance Team's concurrence, a proposed structure that was anticipated to produce the greatest amount of investor interest, highest present value savings and lowest weighted average interest rate on the Recovery Bonds relative to alternative structures. Having conducted its review and provided input and comments on the proposed structuring and marketing of the Recovery Bonds, the Finance Team accepted the approach to register the Recovery Bonds with the Securities and Exchange Commission on a Form SF-1 to facilitate greater liquidity and identify the Recovery Bonds as not "asset-backed securities" as such term is defined by the SEC in governing regulations Item 1101 of Regulation AB.

With the opportunity to provide comment by the Finance Team, PG&E developed and implemented a marketing and structuring plan to incentivize underwriters to market the Recovery Bonds to their customers and to reach out to a broad base of potential investors, including both corporate and ABS investors and investors who have not previously purchased this type of security. PG&E held a group roadshow and further supplemented its marketing efforts at the request of the Finance Team, including adding opportunities for potential investors to have one-on-one and small group calls with PG&E management and the underwriters. Furthermore, the Finance Team noted that the large issuance size likely eliminated any marketing synergies with Series One, and requested that PG&E compare the marketing plan to that which was utilized for Series One, with rationale for any variances resulting from length of overall process, sequencing/exclusion of key marketing tactics, and key confounding marketing events (e.g., Vegas ABS Conference, Federal Reserve meetings, etc.).

Pursuant to the Decision, the Finance Team reviewed and provided input on certificates provided by PG&E and the lead left underwriter, necessary to further align interests and ensure the statutory objective was achieved.[12]

The Finance Team was apprised that PG&E held frequent market update discussions with the underwriting team to develop recommendations for pricing. PG&E and the Finance Team met with the underwriting team before and during the marketing phase. The Finance Team's Financial Advisor engaged with the underwriters on key elements of the marketing, pricing, and syndication process including participating in market updates, pricing discussions and roadshows, using such information to inform the Finance Team's review and feedback on the structure and marketing process. This process included participating in pricing discussions, review of subscriptions, and modifications available, focused on meeting the statutory objective.

[12] Decision, Ordering ¶ 3.

### 5. Transaction Fees and Costs

Pursuant to the Decision, the Finance Team had the right to review all transaction fees and costs for the Recovery Bonds, including Bond Issuance Costs and other Financing Costs.[13] That includes reviewing and approving servicing and administrative fees and associated crediting, and any return on equity contribution.[14]

The Finance Team asked questions and provided input on the fees and costs for the Recovery Bonds, including a review of pricing comparisons and amounts separately credited back by PG&E. The Finance Team provided feedback on various aspects of the fees and costs for the Recovery Bonds. As determined in the Financing Order, the transaction also included a credit enhancement for the Recovery Bonds in the form of the true-up mechanism and an equity contribution of 0.50% of the original principal amount of the Recovery Bonds. The rate of return on this amount, tied to the cost of the securitization, was also determined in the Financing Order, and reviewed by the Finance Team.

### 6. Collateral and Credit Enhancements

Pursuant to the Decision, the Finance Team was directed to determine whether over-collateralization and other additional credit enhancements would be required for the transaction.[15] In response to the Finance Team's inquiries and input, PG&E confirmed no additional enhancements would be required to obtain the highest possible credit rating and achieve the statutory objective.

### 7. Sale of Recovery Bonds

Pursuant to the Decision, the Finance Team had the right to review all material terms of the Recovery Bonds in a negotiated offering through one or more underwriters.[16] The Finance Team worked with PG&E and the underwriters (and each of their respective counsels) to finalize documentation in accordance with established standards for transactions of this sort and the terms of the Decision. The Finance Team was apprised of developments in the marketing process, including the roadshow process and results, the level of interest from investors, questions raised throughout the process and pricing implications.

## V. CONCLUSION

The Finance Team has completed its pre-issuance review and approves the material terms of the Recovery Bonds in the Draft Issuance Advice Letter in accordance with the Decision (pending review of ultimately proposed final sizing and pricing levels). Based on the materials that the Finance Team has received and reviewed, the Finance Team is satisfied that the issuance of the Recovery Bonds as proposed would reduce, to the maximum extent possible, consumer rates on a present value basis as compared to the use of traditional utility financing mechanisms.

---

[13] Decision, Ordering ¶ 3.

[14] Decision, Ordering ¶ 3.

[15] Decision, Ordering ¶ 3.

[16] Decision, Ordering ¶ 3.

Christine Jun Hammond

Christine Jun Hammond
General Counsel

Leuwam Tesfai

Leuwam Tesfai
Deputy Executive Director for Energy
and Climate Policy

# EXHIBIT A

# Draft Issuance Advice Letter

Pacific Gas and Electric Company®

**Sidney Bob Dietz II**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

[ ] [ ], 2022

**Advice [ ]-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject:** **Issuance Advice Letter Submission for Recovery Bonds**

Pursuant to California Public Utilities Commission ("CPUC") Decision (D.) 21-05-015 (Decision), Pacific Gas and Electric Company ("PG&E") hereby transmits for submission, one business day after the pricing date of this series of Recovery Bonds, the initial Fixed Recovery Charge for the series. This Issuance Advice Letter is for the Senior Secured Recovery Bonds Series 2022-B, Tranche(s) [A-1], [A-2], [A-3], [A-4] and [A-5] ("Recovery Bonds").

Pursuant to Ordering Paragraph 4 of the Financing Order, attached hereto as Exhibit 5 is the Finance Team's pre-issuance approval letter dated [ ] [ ], 2022.

## Purpose

This submission establishes initial Fixed Recovery Charge for rate schedules for Consumers, including the Billing Commencement Date. This submission also establishes the Recovery Property to be sold to the Recovery Property Owner ("Special Purpose Entity" or "SPE"). Finally, this submission sets forth the final terms of the Recovery Bonds, including a final estimate of Bond Issuance Costs and estimated Ongoing Financing Costs for the 12-month period following the Closing Date.

## Background

In D. 21-05-015, the Commission authorized PG&E to submit Issuance Advice Letters when final terms and pricing for Recovery Bonds have been established. Issuance Advice Letter submissions are those in which PG&E uses the bond sizing methodology and Fixed Recovery Charge formulas found reasonable by the Commission in D. 21-05-015 to establish initial Fixed Recovery Charge for a series of Recovery Bonds. Using the

methodology approved by the Commission in D. 21-05-015, this submission establishes the initial Fixed Recovery Charge.

**Issuance Information:**

Decision 21-05-015 requires PG&E to provide the following information.

Recovery Bond Name: Senior Secured Recovery Bonds, Series 2022-B
Recovery Property Owner (SPE): PG&E Wildfire Recovery Funding LLC
Bond Trustee(s): The Bank of New York Mellon Trust Company, N.A.
Closing Date: [ ] [ ], 2022
Bond Rating(s): AAA(sf) (S&P) / Aaa(sf) (Moody's)
Principal Amount Issued: $[3,250,000,0000]
Bond Issuance Costs: $[15,979,475] (See Table 1 below)
Bond Issuance Costs as a Percent of Principal Amount Issued: [0.49]%
Recovery Costs Financed: $[3,234,020,525]
Coupon Rate(s): [ ]% (Tranche [A-1]); [ ]% (Tranche [A-2]); [ ]% (Tranche [A-3]); [ ]% (Tranche [A-4]) and [ ]% (Tranche [A-5])
Call Features: None
Expected Principal Amortization Schedule: See Exhibit 1
Scheduled Final Payment Date(s): [ ], 20[ ] (Tranche [A-1]); [ ], 20[ ] (Tranche [A-2]); [ ], 20[ ] (Tranche [A-3]); [ ], 20[ ] (Tranche [A-4]); and [ ], 20[ ] (Tranche [A-5])
Legal Maturity Date(s): [ ], 20[ ] (Tranche [A-1]); [ ], 20[ ] (Tranche [A-2]); [ ], 20[ ] (Tranche [A-3]); [ ], 20[ ] (Tranche [A-4]); and [ ], 20[ ] (Tranche [A-5])
Payment Dates (semi-annually): [June 1] and [December 1]
Annual Servicing Fee as a percent of the issuance amount: [.05]%
Overcollateralization amount for the series, if any: None
Principal Amount of Recovery Property Established: $[3,234,020,525]
FRC Annual Adjustment Date: [March 1]
Semi-Annual Adjustment Dates: [September 1]

Billing Commencement Date: [September 1, 2022]
First Payment Period: Closing Date through and including first Payment Date
Second Payment Period: Day following First Payment Date through and including second Payment Date

**Bond Issuance Costs:**

| **Table 1<br>Bond Issuance Costs** | |
|---|---|
| Underwriter Fees and Expenses | $[13,000,000] |
| Legal Fees and Expenses | [808,200] |
| SEC Registration Fees | [301,275] |

| | |
|---|---|
| Rating Agency Fees | [1,285,000] |
| Accounting Fees and Expenses | [125,000] |
| Section 1904 Fees[1] | [-] |
| Printing/Edgarizing Costs | [150,000-] |
| Servicer Set-up Costs | [-] |
| Bond Trustee Fees and Expenses | [60,000] |
| Original Issue Discount | [TBD] |
| Company Advisory Fee | [-] |
| Miscellaneous | [250,000] |
| Costs of the Commission | [TBD] |
| **Total** | **$[15,979,475]** |
| **Note 1:** Section 1904 Fees computed in accordance with D. 21-05-015. | |

**True-Up Mechanism:**

Not less often than annually, the servicer will compare the actual principal amortization with the scheduled principal amortization as set forth in Exhibit 1. If the servicer forecasts that Fixed Recovery Charge collections will be insufficient to make all scheduled payments of bond principal, interest, and related costs on a timely basis during the current or next succeeding payment period or to replenish any draws upon the capital subaccount, a change to the Fixed Recovery Charge will be requested via a Routine True-Up Mechanism Advice Letter or Non- Routine True-Up Mechanism Advice Letter in accordance with Decision 21-05-015.

**Ongoing Financing Costs:**

**Table 2**
**Estimated Ongoing Financing Costs**

| | First Payment Period | Second Payment Period |
|---|---|---|
| Servicing Fee (PG&E as Servicer) (0.05% of the initial Recovery Bond principal amount) | $[$1,403,819.44] | $[812,500] |
| Administration Fee | [86,388.89] | [50,000] |
| Accountant’s Fee | [-] | [-] |
| Legal Fees/Expenses for PG&E’s/Issuer’s Counsel | [-] | [-] |
| Bond Trustee’s/ Bond Trustee’s Counsel Fees and Expenses | [8,500] | [8,500] |
| Independent Managers’ Fees | [-] | [-] |
| Rating Agency Fees | [20,000] | [20,000] |
| Printing/Edgarizing Fees | [-] | [-] |
| Miscellaneous | [5,000] | [5,000] |
| Return on Equity | [TBD] | [TBD] |

| | | |
|---|---|---|
| **TOTAL ONGOING FINANCING COSTS (with PG&E as Servicer)** | **$[1,523,708.33]** | **$[896,000]** |

**Fixed Recovery Charge:**

Table 3 below shows the current assumptions for each of the variables used in the Fixed Recovery Charge calculation.

| **Table 3**<br>**Input Values For Fixed Recovery Charge[1]** | |
|---|---|
| kWh sales for the applicable period | [82,119,905,750] |
| Percent of revenue requirement allocated to Consumers | [100%] |
| Percent of Consumers' revenue written off (Res/Non-Res) | [0.42%/0.08%] |
| Percent of Consumers' billed amounts expected to be uncollected | [0.34%] |
| Percent of billed amounts collected in current month | [33.68%] |
| Percent of billed amounts collected in second month after billing | [55.43%] |
| Percent of billed amounts collected in third month after billing | [7.35%] |
| Percent of billed amounts collected in fourth month after billing | [1.72%] |
| Percent of billed amounts collected in fifth month after billing | [0.89%] |
| Percent of billed amounts collected in sixth month after billing | [0.59%] |
| Ongoing Financing Costs for the applicable period | [See Table 2] |
| Expected Fixed Recovery Charge outstanding balance as of [__/__/____] | [See Exhibit 3] |

Table 4 shows the initial Fixed Recovery Charge calculated for Consumers. The Fixed Recovery Charge calculations are shown in Exhibit 2.

| **Table 4** | |
|---|---|
| Consumers Fixed Recovery Charge[2] | [ ] ¢/kWh |

Exhibit 4 includes proposed changes to Part IX of PG&E's Preliminary Statement to show the Fixed Recovery Charge rate value which is to be effective [ ] [ ], 2022. Preliminary Statement Part IX is included in this advice letter on an illustrative basis and will be submitted again in PG&E's [ ] rate change advice letter before it is made effective on [ ] [ ], 2022.

**Recovery Property:**

[1] Applicable period from [ ] through [ ].
[2] For residential rates, PG&E shall retain the total rate relationships by tier determined by D.15-07-001 with the addition of the Fixed Recovery Charge and Customer Credit.

Recovery Property is the property described in Public Utilities Code Section 850(b)(11) relating to the Fixed Recovery Charge set forth herein, including, without limitation, all of the following:

(1) The right, title and interest in and to the Fixed Recovery Charge set forth herein, as adjusted from time to time.

(2) The right to be paid the principal amount of the Recovery Bonds, together with interest thereon as the same become due as shown on Exhibit 3, together with all Ongoing Financing Costs as the same become due.

(3) The right, title and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from the Fixed Recovery Charge, as set forth herein.

(4) All rights to obtain adjustments to the Fixed Recovery Charge under the True-Up Mechanism.

These Fixed Recovery Charge, as adjusted from time to time, shall remain in place until the total amounts in Exhibit 3 are paid in full to the owner of the Recovery Property, or its assignee(s).

**Description of Exhibits**

Exhibit 1 to this Issuance Advice Letter presents the scheduled principal amortization schedule for the Recovery Bonds.

Exhibit 2 presents the Fixed Recovery Charge calculations.

Exhibit 3 presents the amounts receivable and expected principal amount amortization.

Exhibit 4 provides proposed changes to Part IX of PG&E's Preliminary Statement.

Exhibit 5 provides the pre-issuance approval letter of the Finance Team.

**Effective Date**

In accordance with Decision 21-05-015, unless before noon on the fourth business day after pricing the Commission staff rejects the Issuance Advice Letter, the Issuance Advice Letter and the Fixed Recovery Charge established by an Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing, and pursuant to Section 850.1(h), the Recovery Property established by the Financing Order, will come into being simultaneously with the sale of the Recovery Property to the SPE. The Fixed Recovery Charge will continue to be effective, unless they are changed by a subsequent

True-Up Mechanism Advice Letter. All of the Recovery Property identified herein constitutes a current property right and will continuously exist as property for all purposes.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically to parties shown on the attached list and the parties on the service list for A.21-01-004. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

Attachments

Attachment 1: Exhibits 1-5

Exhibit 1: Scheduled Principal Amortization Schedule for the Recovery Bonds

Exhibit 2: Fixed Recovery Charge Calculation

Exhibit 3: Amounts Receivable and Expected Principal Amount Amortization

Exhibit 4: Proposed Changes to Part IX of PG&E's Preliminary Statement

Exhibit 5: Pre-Issuance Approval Letter of the Finance Team

cc: Service List for A.21-01-004

**PG&E Gas and Electric**
**Advice Submittal List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
Braun Blaising Smith Wynne, P.C.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

East Bay Community Energy Ellison Schneider & Harris LLP
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_38** | Refer to Kentucky Power's response to Staff's Sixth Request, Item 9, Attachment 1. Provide details for the items listed as "included." Include in the response the purpose of the flights, percent allocated to Kentucky Power, and the basis for the allocations. |

**RESPONSE**

Please refer to KPCO_R_KPSC_PHDR_28_Attachment1 for the purpose of the flights. Please refer to KPCO_R_KPSC_PHDR_38_Attachment1 for the percent allocated to Kentucky Power, and the basis for the allocations.

Witness: Heather M. Whitney

Kentucky Power Company
KPSC Case No. 2023-00159
Commission Staff's Post Hearing Data Requests
Dated December 5, 2023

**DATA REQUEST**

| | |
|---|---|
| **KPSC PHDR_39** | Refer to Kentucky Power's response to Staff's Sixth Request, Item 9, Attachment 2. Provide the entire document or explain the missing page numbers. |

**RESPONSE**

Please see KPCO_R_KPSC_PHDR_39_Attachment1 for the requested information.

Document pages were inadvertently omitted from the response to Staff's Sixth Request, Item 9, Attachment 2.

Witness: Heather M. Whitney

AMERICAN ELECTRIC POWER

# Use of Corporate Aircraft Policy

| | | | |
|---|---|---|---|
| **Title:** | **Use of Corporate Aircraft** | **Date:** | 02.01.[illegible] |
| **Owner:** | Therace M. Risch<br>EVP, Chief Information & Technology Officer | **Sponsoring Area(s):** | Aviation Services |

## Policy Statement:

When used in conjunction with sound Business Continuity principles, the corporate aircraft are tools that allow AEP employees, board members and their third party advisors to conduct business in a safe, effective, and efficient manner. In addition, this tool allows AEP executives to maximize their time for the benefit of the corporation. The corporate aircraft are to be used only for business purposes unless specifically approved in accordance with this policy or used under an Aircraft Time Sharing Agreement providing for personal travel.

## Detail:

**Pilot in Command**

- The Pilot in Command is responsible for the safety of the crew and passengers as well as the condition of the corporate asset and will always have complete control over the decision to fly or not fly.

**Aircraft Time Sharing Agreement**

- Aircraft Time Sharing Agreements (TSAs) are permitted by the Federal Aviation Administration. The Timeshare Agreement allows an individual to reimburse a corporation for certain expenses that occur as a result of that individual using the corporate aircraft for personal travel.
- American Electric Power Service Corporation may enter into such agreements with the Chief Executive Officer and with the Executive Chair.
- Details regarding the reimbursable expenses and program restrictions are found in the executed Aircraft Time Sharing Agreement located in each designated aircraft.

**AEP Business Travel**

- Use of company owned, leased and chartered aircraft (AEP Provided Aircraft) for AEP Business Travel is permitted for members of AEP's Chief Executive Officer Executive Management Team (CEOEMT).
- The scheduling and use of AEP Provided Aircraft for AEP Business Travel by other employees requires the approval of a CEOEMT member.
- AEP Business Travel is defined as a trip where the primary purpose is integrally and directly related to the performance of the executive's, board member's or third party advisor's duties to AEP.

**Approvals**

- Use of AEP Provided Aircraft for any reason other than AEP Business Travel by employees other than the CEO or Executive Chair requires the approval of the CEO on a trip by trip basis. Unless such travel is under a TSA referenced above, use of AEP Provided Aircraft by the CEO or

Executive Chair for any reason other than AEP Business Travel requires the specific approval of the Chair of the Human Resources Committee of the Board of Directors.

- The use of AEP Provided Aircraft requires the approval of a CEOEMT member.

- A CEOEMT member may approve the transportation of non-AEP employees if an AEP employee is aboard the aircraft on AEP Business Travel and the non-AEP employee's travel has no incremental cost to the company.

- CEO approval is required for non-AEP employees use of corporate aircraft if there is no AEP employee aboard the aircraft on AEP Business Travel or if the non-AEP employee's travel has an incremental cost to the company.

**Business Travel with Spouse or a Guest**

- Spouses or guests of members of the CEOEMT may travel on AEP Provided Aircraft if the primary purpose of the flight is AEP Business Travel and there is no incremental cost (other than de minimis food and beverage costs) to AEP for the travel of the spouse or guest. Executives do not need to accompany their spouse or guest on an AEP Provided Aircraft provided they are both traveling to the same destination. No reimbursement for a flight may be accepted from a guest unless the AEP Legal Department provides a written opinion that the reimbursement, and the amount thereof, is allowed under FAA regulations.

- For example, spouses or a guest may travel on AEP Provided Aircraft to AEP board meetings and industry meetings, if the trip qualifies as AEP Business Travel and there is no incremental cost to AEP for the spouse's or guest's travel. To determine if there is an incremental cost, AEP Aviation Services will include the cost of any required aircraft changes, additional aircraft and any necessary operational changes like fuel stops. No reimbursement for incidental costs resulting from a spouse's or guest's travel may be accepted unless the AEP Legal Department provides a written opinion that the reimbursement, and the amount thereof, is allowed under FAA regulations.

- CEOEMT approval is required for other employees to travel with a spouse or guest on AEP Provided Aircraft.

- Unless the employee's spouse is employed and compensated by the company as an employee or contractor, and is required to actively participate in a business function, such as speaking on a business subject, the IRS considers travel on AEP Provided Aircraft by an employee's spouse or guest to be a taxable benefit. The value of this benefit and the tax withholding thereon will be calculated using the Standard Industry Fair Levels (SIFL) and be withheld from the employee's pay.

**Personal Travel and Personal Stops on Business Trips**

- Unless such travel is subject to the Aircraft Time Sharing Agreement referenced above, the use of AEP Provided Aircraft for any travel other than AEP Business Travel is prohibited, unless approved by the CEO or, for the CEO, approved by the Chair of the Human Resources Committee of the Board of Directors.

- For the executive officers included in AEP's proxy statement, Non-AEP Business Travel is likely to require reporting as a perquisite. Non-AEP Business Travel is also likely to be considered to be a taxable benefit to the recipient, for which AEP is required to withhold taxes based on the SIFL methodology.

AMERICAN ELECTRIC POWER

**Use of Corporate Aircraft Policy**

- SEC regulations require reporting of the incremental cost of using AEP Provided Aircraft for travel that is not AEP Business Travel as All Other Compensation for the executive officers included in AEP's proxy statement. Any questions that arise as to what types of travel are AEP Business Travel will be determined by the AEP Legal Department based on whether or not such travel gives rise to an incremental cost under the SEC rules governing the reporting requirements for AEP's Proxy Statement.

- Travel to industry meetings such as EEI and INPO is considered AEP Business Travel. Travel to attend outside public company and charity board meetings is generally not AEP Business Travel pursuant to this policy, unless the AEP Legal Department determines that the trip is AEP Business Travel. Before scheduling corporate aircraft for travel that may not meet the definition of AEP Business Travel, executives are responsible for obtaining a determination from AEP Legal.

- Trips that include personal stops, regardless of stop duration and flight time, are not AEP Business Travel unless such stops have a business or aircraft operational purpose.

- Repositioning aircraft (deadhead legs) is considered AEP Business Travel only if repositioning the aircraft is required for AEP Business Travel. The cost of repositioning the aircraft is billed to the office of the CEO. Employees may fly as passengers during repositioning legs without bearing the cost of the flight so long as the employee does not influence the departure time, the route or the destination.

- Travel to or from an employee's second home, vacation destination or any residence other than the one nearest the employee's primary work location is generally not AEP Business Travel.

**Emergency Travel**

- AEP employees may use AEP Provided Aircraft for reasons other than AEP Business Travel in emergency situations with the approval of the CEO. Such travel is likely to be considered to be a taxable benefit, for which AEP is required to withhold taxes based on the SIFL methodology. The incremental cost to AEP is also likely to be required to be reported as a perquisite in AEP's proxy statement if used by an executive officer.

**Executive Travel Policy for Business Continuity**

- Functional and department leadership will be mindful not to schedule too many direct reports or employees with vital knowledge when determining the passenger complement for corporate aircraft and ground transportation.

- A CEOEMT member may not travel with more than two-thirds of his or her direct reports,

- The CEO and Executive Chair shall not travel together (unless one person holds both positions).

- The CEO and President shall not travel together if different individuals hold those titles,

- No more than 4 CEOEMT members shall travel together,

- No more than 3 executives holding the office of President of any AEP public utility operating company shall travel together,and

- No more than 4 board members shall travel together.

**Examples**

- A Vice President in Generation needs to tour a new plant that is currently under construction with several members of her team. The trip can be accomplished in one day and the Vice President views the use of the corporate aircraft as a way to save time and travel expenses. ***The Vice President must obtain approval from the Executive Vice President of Generation.***

- Two members of the outside auditing firm are expected to make a presentation to the Board of Directors at an offsite board meeting. The auditing firm employees will be traveling aboard the corporate aircraft with several AEP employees. ***The transportation of the two non AEP employees must be approved by a CEOEMT member.***

- An AEP employee working storm duty approximately 1000 miles from home is critically injured in a traffic accident. The employee's supervisor would like to use the corporate aircraft to fly the injured employee's wife and two children to the city where the employee is hospitalized. Due to the timing of the flight, there will be no AEP employees aboard the aircraft. ***The CEO must approve this flight.***

- A Vice President in the Transmission group has been selected to receive a lifetime achievement award from an industry group in New York City. The Vice President's spouse will also be honored during the dinner. ***The Executive Vice President of Transmission must approve the transportation of the Vice President and the Vice President's spouse if there would be any incremental cost to AEP.***

- A CEOEMT member is traveling to Europe for a family vacation. Due to the Executive Council members hectic work schedule, the Executive Council member has decided to meet his spouse in New York where both will depart on a commercial flight to London. The Executive Council member would like to use the corporate aircraft to fly from Columbus to New York. ***This flight is prohibited, unless specifically approved by the CEO.***

- A CEOEMT member has a vacation home in Tampa Florida. The Executive Council member is scheduled to attend a business conference in Naples Florida for one day during the middle of a five day scheduled vacation. The Executive Council member would like to use the corporate aircraft to fly to and from Tampa Florida and she will drive to the business conference in Naples Florida. ***This flight must be approved by the CEO, since the primary purpose of the trip is not AEP Business Travel. The trip would be permitted if AEP Legal determined that the primary purpose was to attend the business meeting, as might be the case if it were a three day meeting with a two day weekend stay at the vacation home.***

- A CEOEMT member serves as a Director for a Fortune 50 company. The Executive Council member receives compensation to attend its Board meetings. The Executive Council member would like to use the corporate aircraft to fly to Atlanta to attend a Board meeting. ***This flight is not AEP Business Travel and must be approved by the CEO.***

- A CEOEMT member is on vacation in Florida, having flown there with her family on a commercial flight. Urgent business comes up unexpectedly while the executive is on vacation, and the CFO requests that she attend a meeting in New York City during her vacation. The corporate plane picks her up in Florida and takes her to the meeting in New York and returns her to Florida after the meeting. ***This trip would be AEP Business Travel, but AEP Legal should generally be consulted to confirm that a trip is AEP Business Travel if it involves a vacation or a second home.***

AMERICAN ELECTRIC POWER

Use of Corporate Aircraft Policy

- Aviation Services must reposition an aircraft to the Cook Nuclear plant in order to fly the Chief Nuclear Officer to an industry meeting. An employee in the Legal department needs to travel to Cook for a meeting on the day the aircraft is to be repositioned to Cook. The Legal department employee has no influence over the schedule of the flight and is able to fly as a passenger. ***This flight is considered AEP Business Travel and the cost of the repositioning flight will be billed to the office of the CEO.***

**Periodic Travel and Policy Review and Revision**

- Senior AEP Management and the HR Committee of AEP's Board of Directors will periodically review use of AEP Provided Aircraft for both AEP Business Travel and other travel under this policy and may direct management to amend the policy as it deems appropriate.

**Glossary**

- The Chief Executive Officer Executive Management Team (CEOEMT) is comprised of all Executive Vice Presidents.

## Review / Revision:

Reviewed by:

| | |
|---|---|
| Stephen L. Swick, VP & Chief Security & Privacy Officer | 10/20/2022 |

Approved by:

| | |
|---|---|
| David M. Feinberg, EVP General Counsel & Secretary | 10/20/2022<br>12/01/2022 |
| Therace M. Risch, EVP Chief Info & Technology Officer | 10/20/2022<br>12/01/2022 |
| Phillip R. Ulrich, EVP Chief Human Resources Officer | 12/01/2022 |

**VERIFICATION**

The undersigned, Scott E. Bishop, being duly sworn, deposes and says he is the Regulatory Consultant Senior for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Scott E. Bishop

Scott E. Bishop

Commonwealth of Kentucky )
) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott E. Bishop, on December 8, 2023.

Marilyn Michelle Caldwell
Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

**VERIFICATION**

The undersigned, Stephen D. Blankenship, being duly sworn, deposes and says he is the Region Support Manager, for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Stephen D. Blankenship

Stephen D. Blankenship

| | | |
|---|---|---|
| Commonwealth of Kentucky | ) | |
| | ) | Case No. 2023-00159 |
| County of Boyd | ) | |

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen D. Blankenship, on December 11, 2023.

Marilyn Michelle Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

## Burkholder Verification Form.doc

DocVerify ID: 1591628B-1480-47BE-9B39-19B0942DEBA0
Created: December 08, 2023 09:07:55 -8:00
Pages: 1
Remote Notary: Yes/ State: KY



**E-Signature Summary**

**E-Signature 1: Joshua D Burkholder (JDB)**
December 08, 2023 09:52:38 -8:00 [216BC63E9B17] [167.239.221.103]
jburkholder@aep.com (Principal) (Personally Known)

**E-Signature Notary: Marilyn Michelle Caldwell (MMC)**
December 08, 2023 09:52:38 -8:00 [F93FE4AC67EC] [167.239.221.105]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

## VERIFICATION

The undersigned, Joshua D. Burkholder, being duly sworn, deposes and says he is the Managing Director of Transmission RTO Policy, for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Joshua D Burkholder

Joshua D. Burkholder

Commonwealth of Kentucky )
) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Joshua D. Burkholder, on December 8, 2023.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

My Commission Expires May 5, 2027 Notarial act performed by audiovisual communication

Notary ID Number KYNP71841

## VERIFICATION

The undersigned, Jaclyn N. Cost, being duly sworn, deposes and says she is a Regulatory Consultant Principal for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Jaclyn Cost
Jaclyn N. Cost

Franklin County )
Ohio )
)

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jaclyn N. Cost, on December 12 2023.

Notary Public

My Commission Expires Never

Notary ID Number NO ID

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

docVerify

# Fetter Verification Form.doc

| | |
|---|---|
| DocVerify ID: | B394078E-3664-466A-801F-46292C0591AA |
| Created: | December 08, 2023 09:32:31 -8:00 |
| Pages: | 1 |
| Remote Notary: | Yes/ State: KY |

This document is a DocVerify VeriVaulted protected version of the document named above. It was created by a notary or on the behalf of a notary. and it is also a DocVerify E-Sign document, which means this document was created for the purposes of Electronic Signatures and/or Electronic Notary. Tampered or altered documents can be easily verified and validated with the DocVerify veriCheck system This remote online notarization involved the use of communication technology.

Go to www.docverify.com at any time to verify or validate the authenticity and integrity of this or any other DocVerify VeriVaulted document.

**E-Signature Summary**

**E-Signature 1: Steven M. Fetter (SMF)**
December 08, 202310:03:31 -8:00 [F12925099B95] [73.221.181.100]
regunf@gmail.com (Principal) (Personally Known)

**E-Signature Notary: Marilyn Michelle Caldwell (MMC)**
December 08, 2023 10:03:31 -8:00 [A33C3FF00D3A] [167.239.221.105]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

# VERIFICATION

The undersigned, Steven M. Fetter, being duly sworn, deposes and says he is the President, of Regulation Unfettered, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Steven M. Fetter

Steven M. Fetter

Commonwealth of Kentucky )
)
County of Boyd )

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Steven M. Fetter, on December 8, 2023.

Marilyn M Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

My Commission Expires May 5, 2027 Notarial act performed by audio-visual communication

Notary ID Number KYNP71841

## VERIFICATION

The undersigned, Lerah M. Kahn, being duly sworn, deposes and says she is the Manager of Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief..

Lerah M. Kahn

Lerah M. Kahn

Commonwealth of Kentucky )
 ) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on December 8, 2023

Marilyn Michelle Caldwell
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

## VERIFICATION

The undersigned, Timothy C. Kerns, being duly sworn, deposes and says he is the Vice President of Generating Assets, for Appalachian Power Company and Wheeling Power Company, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Timothy C Kerns

Timothy C. Kerns

Commonwealth of Kentucky )
) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Timothy C. Kerns, on December 8, 2023

Marilyn Michelle Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

MyCommissionExpires May 5, 2027

Notary ID Number KYNP71841

## VERIFICATION

The undersigned, Franz D. Messner, being duly sworn, deposes and says he is the Managing Director of Corporate Finance for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Franz D. Messner

**State of Ohio** )
) Case No. 2023-00159
**Franklin County** )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Franz D. Messner, on 12/12/2023.

Notary Public

My Commission Expires

NOTARIAL SEAL STATE OF OHIO

David C. House, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.

Notary ID Number ____________

**VERIFICATION**

The undersigned, Katrina T. Niehaus, being duly sworn, deposes and says she is the Managing Director, Head of Corporate Asset Backed Securities Finance Group, for Goldman, Sachs and Company, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Katrina T. Niehaus

______________________ )
                                   ) Case No. 2023-00159
_________________ )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Katrina T. Niehaus, on 12/11/2023.

Notary Public

My Commission Expires ______

RITA VELAMISA
Notary Public - State of New York
No. 01VE6441147
Qualified in New York County
My Commission Expires 09/19/2026

Notary ID Number ______________

## VERIFICATION

The undersigned, Everett G. Phillips, being duly sworn, deposes and says he is the Vice President, Distribution Region Operations for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Everett G. Phillips

Everett G. Phillips

| | | |
|---|---|---|
| Commonwealth of Kentucky | ) | |
| | ) | Case No. 2023-00159 |
| County of Boyd | ) | |

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Everett G. Phillips, on December 8, 2023.

Marilyn Michelle Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

## Schlessman Verification Form.doc

| | |
|---|---|
| **DocVerify ID:** | **11CAF01E-63A8-4DD5-B050-10A806E89055** |
| Created: | December 11, 2023 10:07:50 -8:00 |
| Pages: | 1 |
| Remote Notary: | Yes/ State: KY |



### E-Signature Summary

**E-Signature 1: Linda Schlessman (LS)**
December 11, 202310:57:28 -8:00 [E7EFB0E20005] [23.245.121.218]
lmschlessman@aep.com (Principal) (Personally Known)

**E-Signature Notary: Marilyn Michelle Caldwell (MMC)**
December 11, 2023 10:57:28 -8:00 [A5E817EFF392] [167.239.221.104]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

## VERIFICATION

The undersigned, Linda M. Schlessman, being duly sworn, deposes and says she is the Tax Accounting and Regulatory Support Manager for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Linda Schlessman

Linda M. Schlessman

Commonwealth of Kentucky )
)
County of Boyd )

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Linda M. Schlessman, on December 11, 2023.

Notary Public

MARLYNMCHELLECALDWELL
ONLINE NOTARY PUBLIC
STATEAT LARGE KENTUCKY
Commission# KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

**VERIFICATION**

The undersigned, Michael M. Spaeth, being duly sworn, deposes and says he is the Regulatory Pricing and Analysis Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Michael M. Spaeth

Franklin County )
Ohio ) Case No. 2023-00159
)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Michael M. Spaeth, on December 12 2023

Notary Public

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

NOTARIAL SEAL STATE OF OHIO

My Commission Expires Never

Notary ID Number No ID

## VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Alex E. Vaughan

Franklin County )
Ohio )
)

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 12/7/23.

Notary Public

My Commission Expires 5/4/2028

Notary ID Number 2018-RE-707303

KIM WOLFENBERGER - NOTARY PUBLIC
STATE OF OHIO
MY COMMISSION EXPIRES 5/4/2028

**VERIFICATION**

The undersigned, Katharine I. Walsh, being duly sworn, deposes and says she is a Director of Regulatory Pricing and Analysis for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Katharine I. Walsh
Katharine I. Walsh

Franklin County )
Ohio ) Case No. 2023-00159
)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Katharine I. Walsh, on December 12, 2023

Notary Public

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires Never

Notary ID Number NO ID

**VERIFICATION**

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief..

Brian K. West

Commonwealth of Kentucky )
) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on December 8, 2023

Marilyn Michelle Caldwell
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

# Whitney Verification Form.doc

| | |
|---|---|
| DocVerify ID: | 5CED8907-1A1B-4A2D-8F2B-9257164B6519 |
| Created: | December 12, 2023 07:06:23 -8:00 |
| Pages: | 1 |
| Remote Notary: | Yes / State: KY |



**E-Signature Summary**

**E-Signature 1: Heather M. Whitney (HMW)**
December 12, 2023 11:05:59 -8:00 [0936B04B9880] [74.113.40.114]
hmwhitney@aep.com (Principal) (Personally Known)

**E-Signature Notary: Marilyn Michelle Caldwell (MMC)**
December 12, 2023 11:05:59 -8:00 [2CCE30F462CB] [167.239.221.105]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

# VERIFICATION

The undersigned, Heather M. Whitney, being duly sworn, deposes and says she is a Director in Regulatory Accounting Services for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Heather M. Whitney
Signed on 2023/12/12 11:05:59 -8:00

Heather M. Whitney

Commonwealth of Kentucky )
) Case No. 2023-00159
County of Boyd )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Heather M. Whitney, on December 12, 2023.

Signed on 2023/12/12 11:05:59 -8:00

Notary P

**MARILYN MICHELLE CALDWELL**
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
**Commission # KYNP71841**
My Commission Expires May 05, 2027
Notary Stamp 2023/12/12 12:05:59 PST 2CCE30F462CB

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841