CASE NO. 2022-00372

LIST OF EXHIBITS

TO THE DIRECT TESTIMONY OF ANDREW C. LEVITT
ON BEHALF OF SIERRA CLUB

Exhibit No.	Description of Exhibit	Protected Status	Format
ACL-1	CV of Andrew Levitt	Public	PDF
ACL-2	LG&E-KU's 2021 Integrated Resource Plan	Public	PDF
ACL-3	LG&E-KU's Responses to Discovery Requests	Public	PDF
ACL-4	PJM Hourly Load Forecast Spreadsheet	Public	Excel
ACL-5	RTO Study Production Costs and Capacity Additions Spreadsheet	Public	Excel
ACL-6	2022 RTO Membership Analysis	Public	PDF
ACL-7	EKPC's 2022 Integrated Resource Plan	Public	PDF
ACL-8	South Carolina Market Reform Report	Public	PDF
ACL-9	Western Energy Imbalance Service and SPP Western RTO Participation Benefits	Public	PDF

EXHIBIT ACL-1

CV of Andrew Levitt

Andrew Levitt

SENIOR CONSULTANT

Washington, DC | +1.215.664.7189 | Andrew.Levitt@brattle.com

Mr. Levitt is an expert in wholesale electricity policy, with a focus on evolving system needs.

He has worked with a wide variety of stakeholders – including utilities, regional transmission organizations (RTOs), and regulators – to address wholesale electricity policies in a changing operational and infrastructure environment. With hands-on expertise in power system processes and operations, he has provided training and consulting for several regional and national utilities.

In the RTO sphere, Mr. Levitt's experience includes the development of capacity value accreditation rules for renewable and storage; foundational market access rules for hybrids and storage; a new reactive power compensation approach; an initial design concept for a capacity market overhaul; and principles and policies for integrating DER into wholesale markets and operations.

As a member of the balloting committee for IEEE Standard 1547-2018, Mr. Levitt offers special expertise in policies that recognize the operational challenges and opportunities associated with the widespread deployment of inverters.

A lecturer in Johns Hopkins University's Energy Policy and Climate program, Mr. Levitt is also a frequent speaker and panelist at industry conferences. His research has been published by the Institute of Electrical and Electronics Engineers (IEEE) and *Energy Policy*, and he is the coauthor of a chapter that appeared in *Future of Utilities – Utilities of the Future*.

Prior to joining Brattle, Mr. Levitt was a Senior Lead Market Strategist and Designer at an RTO serving Atlantic and Midwestern states. He previously worked at a national energy provider, where he managed vehicle-to-grid R&D projects, and an electric utility company in New Mexico.

AREAS OF EXPERTISE

- Integration of renewables, storage, DER, and inverters with power systems and markets
- Economic design and analysis of markets for wholesale energy, capacity, ancillary services, and financial transmission rights
- Resource adequacy analysis, capacity value of resources, and effective load carrying capability
- Demand response market design
- Transmission system modelling, analysis, and pricing

EDUCATION

- **University of Delaware**
  MA in Marine Policy, Center for Carbon-Free Power Integration
- **University of Toronto**
  BS in Physics

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Senior Consultant
- **Johns Hopkins University (2020–Present)**
  Adjunct Faculty, Energy Policy and Climate Program
- **PJM Interconnection (2015–2022)**
  Senior Market Strategist/Senior Lead Market Design Specialist
- **NRG Energy (2012–2014)**
  Manager, Vehicle-to-Grid
- **PNM (2006–2008)**
  Project Controls Manager

TESTIMONY

- *Comments of Andrew Levitt, Senior Market Design Specialist, on behalf of PJM Interconnection*, *FERC Technical Conference on Hybrid Resources*, Docket No. AD20-9-000, (July 23, 2020)
- *Comments of Andrew Levitt, Senior Market Design Specialist, on behalf of PJM Interconnection*, FERC Technical Conference on Distributed Energy Resources, Docket No. AD18-10-000 (April 10, 2018)

SELECTED EXPERIENCE

FOCUS AREAS

- Integration of renewables, storage, DER, and inverters with power systems and markets
- Economic design and analysis of markets for wholesale energy, capacity, and ancillary services
- Resource adequacy analysis, capacity value of resources, and effective load-carrying capability
- Demand response market design
- Transmission system modeling, analysis, and pricing

PROJECTS

- ***Capacity value of renewables and storage in PJM ("ELCC")***
  FERC docket ER21-2043
  Headed PJM effort to revamp rules to calculate the capacity value of all renewables and storage using an effective load-carrying capability (ELCC) method, setting the course for a scalable integration of any type of emerging resources into the capacity market.
- ***Market integration of wholesale DER in PJM, including storage DER***
  FERC docket ER19-462
  Authored PJM provisions for DER storage under FERC Order 841 in 2018 and 2019. Previously, led PJM stakeholder process to explore enhancements to remove barriers to participation in wholesale markets for distributed energy resources (DER). Testified at FERC DER Technical Conference. Served as an advisor for PJM's implementation of Order 2222.
- ***Hybrids market integration for PJM***
  FERC docket ER22-1420

Directed development of clarifications and enhancements to PJM rules to incorporate unique mixes of technology types (e.g., solar+storage hybrids) in all wholesale markets. Testified at FERC Hybrids Technical Conference.

- ***Reactive market redesign for PJM***
  Co-author of initial PJM proposal to reform compensation of reactive power capability to incorporate a performance-based incentive, recognize the full capability of inverter-based resources, and compensate inverter-based resources appropriately for potential lost opportunity costs.

ARTICLES & PUBLICATIONS

- "Impact of Distributed Energy Resource's Ride-through and Trip Settings on PJM's Footprint," with Rojan Bhattarai et al., *2020 IEEE Power & Energy Society General Meeting (PESGM)*, Montreal, Canada (August 2, 2020)
- "The Fully Integrated Grid: Wholesale and Retail, Transmission and Distribution," with Susan Covino and Paul Sotkiewicz, in *Future of Utilities - Utilities of the Future (*F. Sioshansi, editor), Chapter 22 (March 2016)
- "Pricing Offshore Wind Power," *Energy Policy* (October 2011)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- "Energy Storage in Wholesale Markets," panel at Energy Storage Association Policy Forum (2017, 2019, and 2022)
- "Keynote: an Update from PJM," Smart Energy Decisions Accelerate Philly (December 9, 2019)
- "Energy Storage Deployment in PJM," U.S. Department of Energy Electricity Advisory Committee (October 16, 2019)
- "Leading the Transition," panel at Interstate Renewable Energy Council Vision Summit (March 6, 2019)

LANGUAGES

- Spanish (basic)
- Portuguese (basic)

EXHIBIT ACL-2

Louisville Gas and Electric and Kentucky Utilities Company's

2021 Integrated Resource Plan

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

STAFF RECOMMENDATIONS FOR LG&E/KU'S 2021 IRP – July 2020

1. **Load Forecast**
    a. **The potential impact of existing and future environmental regulations affecting the price of electricity and other economic variables continues to be a topic of significant interest. Therefore, the effects of such regulations should continue to be examined by LG&E/KU as a part of their load forecasts and sensitivity analyses in the next IRP filing.**

        Section 5.(3) in Volume I of the 2021 IRP summarizes the potential impacts of higher cost of service on the Companies' load forecast. These impacts are evaluated in the Companies' low energy requirements forecast.

    b. **As discussed in the Joint 2018 IRP, the economics of current cost trends of distributed solar generation and electric vehicle penetration can have important effects on the demand for electricity. An increase in adoption rates of the former will tend to decrease electricity demand while increasing demand for the latter. In addition, LG&E's 2020-00016[1] and Siting Board cases 2020-00040[2] and 2020-00043[3] highlight the improving economics and demand for large scale solar projects, which could have an impact on demand growth. For the next IRP, the Companies should closely monitor, discuss, and model the potential impacts of these trends in both base case and sensitivity analyses.**

        Section 5.(3) in Volume I of the 2021 IRP summarizes the potential impacts of distributed generation and electric vehicles on energy requirements.

        The 2021 IRP includes the planned additions of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[4] Due to the improving economics of utility-scale solar, utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis. The results of this analysis are summarized in Section 5.(4).

    c. **LG&E and KU should continue to monitor and incorporate anticipated changes in EE impacts in their forecasts and sensitivity analyses.**

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[1] Case No. 2020-00016, Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option 3 (Ky. PSC May 8, 2020).

[2] Case No. 2020-00040, Application of Turkey Creek Solar, LLC for an Application for a Certificate of Public Convenience and Necessity to Construct an Approximately 50 Megawatt Merchant Electric Solar Generating Facility in Garrard County, Kentucky Pursuant to KRS 278.700 (Application filed March 27, 2020).

[3] Case No. 2020-00043, Application of Glover Creek Solar, LLC for a Certificate of Public Necessity to Construct an Approximately 55 Megawatt Merchant Electric Solar Generating Facility in Metcalf County, Kentucky Pursuant to KRS 278.700 and 807 KAR 5:110 (Application filed March 27, 2020).

[4] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Section 5.(3) in Volume I of the 2021 IRP summarizes energy efficiency assumptions in the base load forecast.

d. **There were four major driving assumptions comprising the Companies' High and Low scenarios and the results were reported on a combined basis. In addition, the discussion did not include the degree to which the Companies varied each of the factors from the base case. Reporting results on a combined basis provides the extreme case scenarios which, in part, is the point of the analyses. However, such reporting masks the effects of varying individual factors, which could provide useful information. For the next IRP, an expanded and more robust discussion (including the reasonableness of the High and Low assumptions) of each of the factors used to shock the base case forecast. For example, in the Low sensitivity analysis, what circumstances would cause the cost of service decline by 5 percent and how would the lower cost be passed on to which customers and how would that affect demand? In the next IRP, in addition to the cumulative shock to the base case, there should be a disaggregated sensitivity analysis.**

Section 5.(3) in Volume I of the 2021 IRP contains a discussion of the high and low load forecasts, the major driving assumptions, and the degree to which the Companies varied the assumptions. In addition, Section 5.(3) provides the disaggregated impact of each high and low case assumption on the base case forecast.

e. **The Base Case energy and peak demand forecasts are based on a 20-year historical period and the peak winter high demand forecast ranges from 6,355 MW to 6,764 MW by 2033. However, the maximum winter demand in the reserve margin analysis is based on an actual peak of 7,336 MW from 45 years ago. This represents a 981 MW – 572 MW difference. It is somewhat counter intuitive that the reserve margin (which seems unreasonably excessive) could be driven, in part, by an extreme outlier weather event, the effects of which are not even closely matched by the Companies' High peak load forecast. The High winter peak forecast in 2021 (the target year of the 2018 Reserve Margin Analysis) is 6,082 MW; a 1,254 MW difference. It is not clear how the reserve margin analysis results would be affected by altering the weather assumptions to better reflect similar assumptions driving the base case and High Low energy and peak demand forecasts. Such disparities in the assumptions' reasonableness can erode the confidence that may be placed in the forecast results and reserve margin analyses. For the next IRP, the Companies should provide more robust and complete explanations as well as a more consistent use of assumptions driving energy, load, and resource planning forecasts.**

Sections 5.(2) and 5.(3) in Volume I of the 2021 IRP more clearly explain the Companies' weather assumptions. The Companies develop their long-term base, high, and low energy requirements forecasts with the assumption that weather will be average or "normal" in every year. In other words, weather does not explain any differences between the base, high, and low peak demand forecasts. The assumption of normal weather is reasonable for long-term resource planning, but weather from one year to the next is never the same. Therefore, for reliability planning, a completely separate planning analysis focused on the Companies' ability to reliably serve load over a range of weather and unit availability scenarios, the Companies produce hourly load forecasts for a single year based on the weather in each of the last 48 years. The resulting ranges of summer and winter peak demands define the range of uncertainty – due solely to weather – for peak demands in the base energy requirements forecast. Thus, these ranges are comparable only to the summer and winter peak demands in the base energy requirements forecasts.

f. LG&E and KU should include discussion and analysis of the increase in distributed energy resources on load forecasts. This should include behind the meter generation at residential, commercial and industrial customer locations. These should be evaluated separately and cumulatively and include a discussion of drivers encouraging and discouraging such development.

Section 5.(3) in Volume I of the 2021 IRP provides a summary of the factors that impact DER economics and the assumptions underlying the Companies' DER forecasts. The Companies' base distributed solar generation forecast assumes retail rate paid for excess generation, instantaneous netting of usage and generation, and a continuation of the federal ITC for residential customers. On September 24, 2021, the Commission ruling on net metering was released. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the forecast could not be updated to reflect the new NMS-2 rates.

2. **DSM/EE**
   a. **The Companies should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders. These meeting should be more than informational, but entail fluid dialog between all vested parties. Any changes to the DSM-EE program must be discussed in full including a transparent analysis of the cost and benefits inputs.**

      The Companies held a DSM Advisory Group Meeting on 9/17/2021 to kick off the upcoming DSM Filing Planning and Development process. A follow-up Advisory meeting is tentatively being planned in Q4 of 2021 to continue the dialog once some initial budget, participation, and cost-effectiveness scoring is ready. Similar to the process in 2017, the Companies have again engaged with Cadmus, Inc. to assist in the development of the upcoming filing. Cadmus has many years of experience assisting other utilities in planning and developing new DSM programs. Also, they have developed, over many years, an in-house, robust cost-effectiveness software tool that has been utilized across the country as well as with the Companies' last DSM Filing in 2017/2018. Further, please see in Volume I the relevant Sections of 6, 7, and 8 for more information on DSM.

   b. **Staff recommends that LG&E/KU continue to identify cost effective energy efficiency opportunities for large customers and continue to offer incentives that encourage them to adopt or maintain energy-related technologies, sustainability plans, and long-range energy planning.**

      See response to part a. above.

   c. **Staff strongly encourages LG&E/KU to consider making AMS usage data available to customers that is closer aligned to real-time data and to consider prepay metering and real-time pricing options to enhance the customer experience for those customers participating in the AMI Pilot Program. In addition, Staff suggests LG&E/KU examine the feasibility of peak time rebate programs and time-of-use rates.**

      See response to part a. above.

   d. **As required by the IRP regulation (807 KAR 5:058, Section 7(4)(d)), the Companies should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

      The Companies plan to continue to improve their Process and Impact Evaluation, Measurement, & Verification (EM&V) of programs as the addition of AMI interval data becomes more available with AMI full deployment. Also, see response to part a. above.

   e. **Staff encourages LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time.**

      See response to part a. above.

3. **Resource Assessment**
   a. **LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.[5]**

      As requested by SREA, the least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity. All renewable cost assumptions are based on the "Moderate" case forecast from NREL's 2021 Annual Technology Baseline and were evaluated with applicable tax incentives.

   b. **Given the recent filing of Case No. 2020-00016, the next IRP's reserve margin analysis and long-term resource plan analysis should model the effects of increased interest and participation of the Companies' large commercial and industrial customers in purchasing increased amount of renewable energy, which may be generated by third party suppliers as opposed to the Companies' own generation sources.**

      The Companies long-term resource planning analysis reflects the planned additions of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[6] As mentioned previously, utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis. The IRP does not specify whether the additional solar is associated with the Green Tariff Option 3 program, but portions of it could be.

   c. **The 2018 Reserve Margin Analysis is well thought out. The starting premise appears to be that the Companies continue to operate as a standalone entity as opposed to being a member of an RTO. That assumption appears to drive several key input modeling constraints, which in turn may drive a higher reserve margin than would otherwise be the case. The Companies mention anecdotally the retirement of generation capacity within PJM and the reserve margins of neighboring utility systems, which may limit its ability to import power when needed as further support for the maintenance of its high reserve margin. The reduction in installed capacity would seem to support the Companies' planned maintenance of a high reserve margin. However, the Companies make no mention of any reliability concerns within the neighboring regions, availability of or additions to generation capacity, reduced demand within the markets, or whether the neighboring regions' stated reserve margins are considered inadequate for planning purposes. In addition, to whether or not neighboring utilities would have excess energy to sell during LG&E/KU's winter peak demand, there is no support for assumptions regarding available transmission capacity. Without further study, evidence, and discussion, it is difficult to ascertain the risk of not being able to rely on neighboring regions to serve and LG&E/KU being able to import energy that would justify such high reserve margins. The circumstances that allow for neighboring**

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[5] See Appendix for intervenors' comments.

[6] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

regional reserve margins to be relatively lower than the Companies' may also be advantageous to the Companies if it were a member of an RTO. It is possible that under some RTO analysis scenarios, the Companies and their customers may benefit from lower costs, lower reserve margins without sacrificing reliability, and, depending on load profiles, higher revenues overall. Staff also notes that LG&E/KU have upgraded select generation units for blackstart capability and that PJM provides compensation for that capability.[7]

In the 2018 IRP, the Companies' forecasted summer reserve margin was 23.5 percent in 2021. The 2018 IRP Reserve Margin analysis demonstrated that the increased reliability and generation production costs from retiring a marginal generation unit and operating at a lower reserve margin would more than offset the savings associated with the unit's stay-open costs. The low cost of the Companies' existing resources is the primary reason the Companies' existing generation portfolio is economically optimal.

In the 2021 IRP, the basis for the Companies' assumptions regarding available transmission capacity is provided in Section 4.4 of the 2021 IRP Reserve Margin Analysis in Volume III of the 2021 IRP. Furthermore, this analysis includes a sensitivity analysis in Section 5.1 where the maximum available transmission capacity is doubled from 500 MW to 1,000 MW. As discussed in the Companies' 2021 RTO Membership Analysis, the Companies do not recommend RTO membership at this time.

d. In the next IRP, the Companies should provide updated comprehensive and detailed cost/benefit studies comparing the full costs of joining MISO or PJM and all potential benefits such as increased revenues, lower reserve margin requirements, and improved reliability versus operating under its existing operating construct.

The Companies' 2021 RTO Membership Analysis is provided as an attachment to the Companies' 2021 IRP.

e. The Companies should provide greater discussion of and support for (reasonableness) the use of various assumptions used in the reserve margin analysis. If not addressed in Section 2, where appropriate, the input assumptions used in the reserve margin analysis should be consistent with those used in energy, load, and resource planning.

See response to 1e. The primary source of misunderstanding in reviewing the 2018 IRP pertained to load assumptions in the long-term resource planning analysis and the reserve margin analysis. The Companies' have attempted to do a better job demonstrating that load assumptions in both analyses are completely consistent.

f. In addition to the current sensitivity analyses methodology, the Companies should provide the effects of varying the input parameters separately so as to gauge the individual effects on the reserve margin. The Companies should also provide more detailed discussion of the implications of varying the modeling input assumptions and

[7] Staff notes that the Companies have recently completed one RTO study. However, over time, circumstances change and key assumptions that were valid previously may have changed too. See LG&E/KU's response to the Attorney General's First Request for Information, Item 76 (Filed Nov. 1, 2019).

greater support for (reasonableness) of how the modeling inputs are varied in the analyses.

Section 5.1 contains the sensitivity analysis for the 2021 IRP Reserve Margin Analysis. The impacts from varying key inputs are presented separately. In addition, the discussion of the sensitivity analysis is expanded to further assess the reasonableness of the results and provide more information regarding the range of inputs evaluated.

g. For the next IRP, the Companies should incorporate SREA's modeling recommendations regarding capacity only planning, allowing renewable energy to compete directly against existing generation units, and energy storage resources into the modeling and forecast methodology. Other recommendations should be incorporated appropriately.

In the 2021 IRP Long-Term Resource Planning Analysis, least-cost generation portfolios were developed with the goal of minimizing energy costs as well as the cost of new capacity.

h. Staff notes that in addition to the ongoing transmission projects, the Companies have taken steps in conjunction with other Kentucky based utilities to ensure the reliability of their respective transmission systems. For example, in Case No. 2017-00410,[8] the Commission approved the joint application for pre-approval of the sale or purchase of utility-owned transformers with an original book value in excess of $1 million and ancillary equipment pursuant to the agreement for Regional Equipment Sharing for Transmission Outage Storage Restoration (RESTORE Agreement). In the next IRP, in addition to a listing of transmission related projects, (including information contained in its annual Transmission System Improvement Plan, the Companies should provide a more robust and complete discussion of all the actions being taken to enhance the efficiency and reliability of the transmission and distribution systems.

Key distribution reliability and resiliency programs are addressed in Section 8.(2).(a). These programs include an Advanced Distribution Management System (ADMS), substation transformer replacements, aging infrastructure replacements, pole inspection and treatment, volt/VAR optimization and advanced metering infrastructure (AMI). These programs will maintain top quartile reliability performance and increase the flexibility of the distribution system to support the integration of DER.

In addition to the efficient transmission processes to add new generation (including renewables) and incremental load provided in Volume III ("Transmission Information"), programs have been implemented to improve the reliability of the transmission system. These programs include replacement of critical line and substation assets, upgrades to the protection and control systems, improved line sectionalization and automatic restoration through the installation of in-line breakers and switches, enhanced

[8] Case No. 2017-00410, Electronic Joint Application of Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Kentucky Utilities Company, and Louisville Gas and Electric Company for Approval of Transactions Related to the RESTORE Agreement (Ky. PSC Feb. 22, 2018).

vegetation management, pole inspection, and switch maintenance. These programs will ensure long-term system integrity and modernize the transmission system to maintain reliable performance. The Transmission System Improvement Plan and the latest Annual Report can be found at the following links:

> 2016-00370 - ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY
>
> https://psc.ky.gov/pscecf/2016-00370/rick.lovekamp@lge-ku.com/06012021112026/Closed/2-2021_TSIP_Annual_Report.pdf
>
> 2016-00371 - ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY
>
> https://psc.ky.gov/pscecf/2016-00371/rick.lovekamp@lge-ku.com/06012021112143/Closed/2-2021_TSIP_Annual_Report.pdf

i. **Changes in federal and state law and policy could impact the growth of distributed generation, particularly as it relates to net metering. In Kentucky, in Case No. 2019-00256,[9] the Commission initiated an administrative proceeding to consider the implementation of legislation enacted by the 2019 General Assembly. Senate Bill 100, entitled An Act Related to Net Metering (Net Metering Act), which became effective on January 1, 2020. The Companies should address any ruling pertaining to the Net Metering Act in the any future IRPs.**

   See response to 1f.

j. **If not addressed above, the Companies should evaluate energy and capacity including renewable resources that is supplied from resources that are outside LG&E/KU's service territory in their resource assessment and reserve margin analyses. However, in that evaluation all costs, including those associated with transmission and distribution losses, should be included as well the inclusion of any benefits such as government subsidization. In addition, Staff notes that there are a number of merchant solar generation facilities in the process of regulatory approval that may be in response to large industrial customer sustainability goals. The Companies should also incorporate the effects of increased numbers of large renewable facilities within its service territory as a viable resource that is allowed to compete with existing generation.**

   In addition to in-state solar, the Companies' resource screening analysis considered in-state and out-of-state wind. The costs of solar and wind in the Companies' long-term resource planning analysis are consistent with recent RFP responses. Furthermore,

[9] Case No. 2019-00256, Electronic Consideration of the Implementation of the Net Metering Act (Ky. PSC Dec. 18, 2019).

least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity.

k. LG&E/KU should address any possible capacity ratings changes with renewables in their forecast, especially with solar.

The availability of solar during peak events is a key source of uncertainty in the 2021 IRP and is discussed in the 2021 IRP Reserve Margin Analysis.

2021 IRP Resource Screening Analysis

PPL companies

Generation Planning & Analysis
October 2021

Table of Contents

1 Executive Summary

Table 1 and Table 2 list the dispatchable and non-dispatchable resource options that were selected for evaluation in the Long-Term Resource Planning Analysis. These resources set the foundation for a clean energy transition. Non-dispatchable resources include wind and utility-scale solar resources located in Kentucky. Dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines with carbon capture and sequestration ("NGCC w/ CCS"), and 4-hour and 8-hour battery storage. Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions.[1] SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

Table 1: Dispatchable Resources (2022 Installation; 2022 Dollars) Results

			Battery Storage	
	SCCT	**NGCC w/CCS**	**4-hour**	**8-hour**
Summer Capacity (MW)[2]	220	513	1+	1+
Winter Capacity (MW)[2]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[3]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[3]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[3]	22	69	32	58
Firm Gas Cost ($/kW-yr)[4]	22	22	N/A	N/A
Variable O&M ($/MWh)[3]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

With the exception of summer and winter capacity values, firm gas cost assumptions, and renewable contributions to summer and winter peak, the cost and operating inputs for the generation resources in Table 1 and Table 2 are based on the "Moderate" case forecast in the National Renewable Energy Laboratory's ("NREL's") 2021 Annual Technology Baseline ("ATB"). The Companies did not evaluate combined cycle with hydrogen or nuclear resources in the Long-Term Resource Planning Analysis, but these technologies could eventually play an important role in decarbonization and the integration of renewables. In addition, the Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunites for new DSM programs that will be evaluated with data and pilot programs associated with the implementation of AMI.

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[1] NGCC with CCS, like NGCC without CCS, is dispatchable in all weather conditions and has fast ramp rates, but emits less than 10% of the carbon.

[2] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled battery storage resources in 100 MW increments.

[3] Source: NREL's 2021 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2019 dollars, to nominal dollars at 2% annually.

[4] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

Table 2: Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

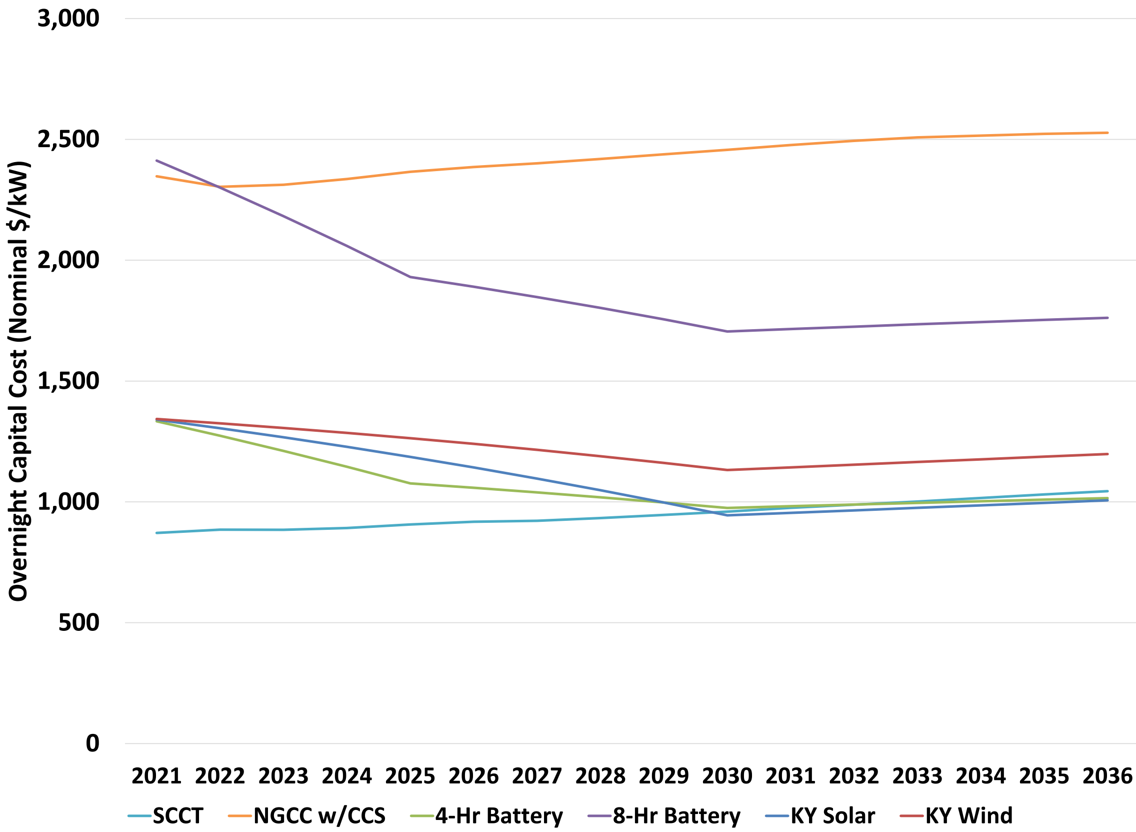
	KY Solar	KY Wind
Summer Capacity (MW)[5]	100+	100+
Winter Capacity (MW)[5]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[3]	25.1%	27.4%
Capital Cost ($/kW)[3]	1,305	1,325
Fixed O&M ($/kW-yr)[3]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[6]	N/A	15

Figure 1 contains NREL's forecast of capital costs through the end of the IRP planning period. As Figure 1 demonstrates, SCCT capital costs are lower than 4-hour battery storage capital costs today; however, by 2030, their capital costs are forecasted to be approximately equal. NREL's fixed O&M assumptions for each resource escalate over time in nominal dollars with the exception of KY Solar and battery storage, which decrease until year 2030 and then escalate. Compared to assumptions in the 2018 IRP, the capital costs of wind and battery technologies for a 2022 installation have decreased and the capital cost of solar resources has increased; however, capital costs for all three technologies are lower by the end of the IRP planning period than capital costs in the 2018 IRP. Fixed operating and maintenance costs have increased significantly from the 2018 IRP for all evaluated technologies with the exception of wind resources.

[5] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled solar and wind resources in 100 MW increments.

[6] Production Tax Credit of $15/MWh included for the first 10 years of wind resources.

Figure 1: Generation Technology Cost Forecast (Nominal Dollars)[7]



Key input assumptions include those listed below.

- Capacity is the net full load output in MW.
- Contribution to peak is the assumed percentage of capacity that is available to serve peak load.
- Net capacity factor is the ratio of the unit's average hourly output over the course of the year to the unit's rated capacity.
- Heat rate is the full load net heat rate.
- Capital cost is the overnight capital expenditure required to achieve commercial operation.
- Fixed operation and maintenance costs are operation and maintenance costs that do not vary with the unit's generation output.
- Firm gas transportation costs are costs associated with reserving firm gas-line capacity.
- Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.
- Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.

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[7] Source: 2021 ATB from NREL (https://atb.nrel.gov/).

2 Generation Technology Options

The following sections include a discussion of the resource options considered in this analysis along with the rationale for selecting the resource options evaluated in the Long-Term Resource Planning Analysis.

2.1 Dispatchable Resources

2.1.1 Natural Gas Simple-Cycle Combustion Turbines

Natural gas-fired SCCT options include traditional frame machines and aero-derivative combustion turbines. They are typically used for peaking power due to their fast ramp rates and relatively low capital costs. Aero-derivative machines are flexible, slightly more efficient than larger frame units, and can be installed with high temperature oxidation catalysts for carbon monoxide control and selective catalytic reduction ("SCR") for nitrogen oxides ("NO_x") control, which allows them to be located in areas with air emissions concerns. Additionally, utilities with significantly higher renewable penetration are building aero-derivatives for integration purposes.[8] While not quite as efficient or flexible, frame simple-cycle machines can also be installed with emission controls and are much less expensive to install and operate on a $/kW basis. The cost of SCCT in the 2021 ATB reflects the cost of frame simple-cycle machines. For these reasons, frame simple-cycle machines were evaluated in the Long-Term Resource Planning Analysis.

2.1.2 Natural Gas Combined-Cycle with Carbon Capture and Sequestration

NGCC units with CCS use both gas and steam turbines together to produce up to 50% more electricity than SCCT using the same amount of fuel. The steam turbine uses waste heat from the gas turbine to generate additional electricity. After combustion, up to 99% of the carbon dioxide emissions are captured to be stored or beneficially used. NGCC units with CCS can respond to significant load swings due to their high ramping capabilities and can be cycled overnight. NGCC with CCS is dispatchable in all weather conditions, has fast ramp rates, has low CO_2 emissions, and thus remains a viable resource with clean energy regulations. New NGCC units with CCS are also capable of burning hydrogen with, or instead of, natural gas, and the economics of green hydrogen produced from renewable energy resources continue to improve.

The Companies are global leaders in carbon capture research and operate one of the two carbon capture systems in operation at power plants in the United States today. In 2006, the Companies began a partnership with the University of Kentucky Center for Applied Energy Research ("UK CAER") focused on improving the cost and efficiency of carbon capture technology. In 2014, the team built Kentucky's largest carbon capture unit at the Companies' E.W. Brown generating station, which remains in operation today. University of Kentucky researchers have used this system to run tests for U.S. Department of Energy-funded research projects and have generated 118 publications and have had 17 U.S. patents issued for their work with another four patents pending. One of the current research projects establishes a method of producing hydrogen as a beneficial byproduct from the carbon capture that could in turn be used as fuel for combustion.

[8] https://www.powermag.com/srp-approves-arizona-expansion-with-16-gas-fired-turbines/.

2.1.3 Energy Storage

Energy storage options provide short-term peaking capacity and voltage frequency management. Compressed air energy storage ("CAES") and pumped hydro energy storage systems store off-peak power to be released during on-peak demand periods. However, the cost of CAES and land-use requirements for pumped hydroelectric facilities make these storage technologies unsuitable in the Companies' service territories.

The Companies have been researching and testing lithium-ion batteries since 2016 for their potential to provide short-term energy storage on a utility scale. The basic composition of a lithium-ion battery includes an anode, a lithium-containing cathode, and an electrolyte solution. When the battery is in operation, lithium ions are moved between the negative anode and positive cathode. While discharging, the ions travel from the anode to the cathode and while charging they travel from the cathode to the anode.

Lithium-ion battery energy storage systems have virtually instantaneous response times, allowing flexibility in load management, and their scalability is an advantage over larger peaking options such as frame SCCTs. At higher levels of intermittent renewable penetration, lithium-ion batteries can be used to ameliorate solar intermittency by power smoothing, which discharges power instantaneously when solar output drops, and charges to absorb power when solar power rises suddenly. They can also serve to store excess solar generation from the day and discharge it at night, which can limit the need for solar curtailment. Batteries are also capable of frequency and voltage regulation when installed at scale.

In RTOs, connecting batteries to renewables can increase the capacity value of renewables based on current market rules. But battery storage has the most value for vertically integrated utilities when it is connected to the grid because it increases the likelihood of the battery being charged when needed. The Companies evaluated 2, 4, 6, 8, and 10 hour batteries at varying levels of renewables and determined that 4 and 8 hour batteries are the optimal choice for serving their customers; therefore, 4 and 8 hour batteries were evaluated in the Long-Term Resource Planning Analysis. Table 3 compares costs and assumptions for SCCT and 4- and 8-hour battery storage installed in years 2022 and 2031.[9] According to NREL, SCCT capital costs are expected to increase over time and battery storage capital costs are expected to decrease.

Table 3: Comparison of SCCT and Battery Storage in 2022 and 2031 (Nominal Dollars)

	2022 Installation			2031 Installation		
		Battery Storage			Battery Storage	
	SCCT	4-hour	8-hour	SCCT	4-hour	8-hour
Capital Cost ($/kW)[3]	885	1,274	2,300	975	982	1,715
Fixed O&M ($/kW-yr)[3]	22	32	58	27	25	43
Firm Gas Cost ($/kW-yr)[4]	22	N/A	N/A	24	N/A	N/A
Variable O&M ($/MWh)[3]	5.24	N/A	N/A	6.27	N/A	N/A
Round-Trip Efficiency	N/A	85%	85%	N/A	85%	85%
Book Life (Years)	30	15	15	30	15	15

[9] 2022 and 2031 are the first and tenth years of the IRP planning period, respectively.

Table 4 shows a comparison of the levelized cost of energy ("LCOE") for SCCT and battery storage resources at varying natural gas prices and charging costs, respectively, and assuming 16.7% capacity factor for both resource types. Battery storage technology is currently disadvantaged due to its cost and much shorter life compared to SCCT resources. By 2031, the LCOE for SCCT and battery storage resources are similar, depending on natural gas prices and charging cost assumptions. However, NREL's SCCT capital cost reflects the cost of constructing a single SCCT at a greenfield site. Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower.

Table 4: LCOE of SCCT and 4-Hour Battery Storage ($/MWh)

Installation Year	SCCT Natural Gas Price Forecast			4-Hour Battery Storage Charging Cost ($/MWh)		
	Low	**Mid**	**High**	**25**	**30**	**35**
2022	113.91	125.18	135.61	150.59	157.22	163.85
2031	125.64	136.91	147.34	123.68	130.31	136.94

All batteries, including lithium-ion batteries, experience round-trip energy efficiency losses of 15% to 25%, which is primarily lost as waste heat when power travels through the inverter transforming power AC to DC during charging and then DC back to AC when discharging. A round-trip efficiency of 85%, accounting for these inverter losses, is considered standard. However, round-trip efficiencies of 75% have also been observed particularly during very hot or cold weather when significant amounts of energy are required for heating or cooling to keep the batteries within their relatively narrow optimal temperature range. In simple terms, for every 1 MWh of energy stored in batteries, 0.85 MWh can be used.

Utility scale batteries are rated by both their energy and power capacities. For a 1-megawatt ("MW") 4 megawatt-hour ("MWh") battery, the maximum power input or output is 1 MW but not all of the battery's energy capacity (4 MWh) can be used. Lithium-ion batteries are susceptible to fire and thermal runaway especially at higher states of charge ("SOC"). For this reason, SOC is typically limited between 5% and 95%, which results in a 10% reduction in available battery capacity that needs to be accounted for when determining battery installation capacities. At their energy storage testing facility, the Companies limit SOC for safety to between 10% and 90%, meaning that 20% of the battery's energy capacity is unused. Some utilities limit lithium-ion batteries from 25% to 75%, meaning 50% of the battery is unused, and only 50% of the battery's capacity is available. In simple terms, assuming 10% reduction in available battery capacity means for every 1 MWh of energy storage installed, only 0.9 MWh is usable.

The Companies are a leader in utility scale lithium-ion battery research, and installed Kentucky's first and largest battery site with a 1 MW, 2 MWh battery at the E.W. Brown Generating Station in 2016. The battery is continuously monitored and performance data is viewed via a real-time battery performance dashboard. The data is shared with Pacific Northwest National Laboratory and the Electric Power Research Institute. At this site, the Companies are able to program the battery in different operating modes to understand their settings and functionality. Often used is target state of charge where solar energy from the day is stored to be discharged overnight. The battery also allows for research into best practices for safety. In addition to the knowledge gained at the E.W. Brown battery site, the Companies participate in industry research programs to collaborate and share knowledge with other leaders in lithium-ion battery research.

Subject matter experts at the Companies working with researchers from the University of Kentucky have collaborated on multiple research topics related to solar and battery energy storage systems. Over the past three years, nine academic papers and presentations based on data retrieved from the E.W. Brown Solar Dashboard and E.W. Brown 1-megawatt, 2-megawatt-hour battery have been published in international journals, including the distinguished IEEE Transaction for Industry Applications. The publications have covered topics including how energy storage systems can be used to improve the capacity factor for solar farms, methods for developing accurate battery models for computer simulations studies, analysis of solar plant configurations with battery systems, and defined procedures for identifying the equivalent circuit parameters for utility-scale lithium-ion batteries. In a continuation of the partnership, the University of Kentucky Center for Applied Energy Research ("CAER") and the Companies are studying how to recycle lithium-ion batteries once they reach the end of their useful life.

2.1.4 Demand-Side Management

The Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunites for new DSM programs that will be evaluated with data and pilot programs associated with the implementation of AMI.

2.2 Non-Dispatchable Resources

2.2.1 Solar

Photovoltaic ("PV") solar is a proven technology option for daytime energy and a viable option to pursue renewable goals and reduce emissions. Solar generation is a function of the amount of sunlight (i.e., electromagnetic radiation) incident on a surface per day, measured in kWh/ m^2/day. Kentucky receives between 4 and 5.5 kWh/m^2/day. Areas in the western United States with high rates of solar development receive over 7.5 kWh/m^2/day. In Kentucky, the summer peak contribution of solar resources is assumed to be 79 percent of total solar capacity. The PV Solar option was further evaluated in the Long-Term Resource Planning Analysis, which considers the impact of the federal Investment Tax Credit ("ITC").[10]

Table 5 shows a comparison of residential and utility-scale solar resources, using NREL's 2021 ATB assumptions for 2022 and 2031 installations.[11] Utility-scale solar has lower capital and fixed O&M costs, a higher capacity factor, and a lower weighted average cost of capital ("WACC") compared to Residential Solar. For this reason, the Companies evaluated Utility-Scale Solar in the Long-Term Resource Planning Analysis.

[10] The federal ITC for PV solar is currently 26% (see http://programs.dsireusa.org/system/program/detail/658). The Long-Term Resource Planning Analysis assumes this level of ITC continues through the planning period.

[11] The Companies used "Class 6" solar from the 2021 ATB to represent a solar resource located in Kentucky. 2022 and 2031 are the first and tenth years of the IRP planning period, respectively.

Table 5: Comparison of Residential and Utility-Scale Solar (Nominal Dollars)

Item	2022 Installation		2031 Installation	
	Residential Solar	Utility-Scale Solar	Residential Solar	Utility-Scale Solar
Capital Cost ($/kW)[3]	2,514	1,305	1,259	955
Fixed O&M ($/kW-yr)[3]	27.42	23.38	16.90	21.00
Capacity Factor[3]	15.1%	25.1%	15.3%	27.3%
Weighted Average Cost of Capital ("WACC")[3]	4.38%	4.25%	4.38%	4.25%
Levelized Cost of Energy ($/MWh)	108.18	38.62	56.47	28.05

Fixed O&M in NREL's 2021 ATB for utility-scale solar is notably higher compared to the 2020 ATB. As a result, the levelized cost of energy for utility-scale solar is approximately $10/MWh higher than the cost of Rhudes Creek Solar ($27.82/MWh) in 2022 and does not approach the Rhudes Creek price until 2031. To align the analysis with the Rhudes Creek price, the 2031 cost of solar was utilized throughout the IRP planning period.

2.2.2 Wind

The viability of wind generation for a given region is dependent on wind speeds. Kentucky has average wind speeds that are less than 12.5 mph. Areas with wind speeds of at least 14.5 mph are better suited for wind generation. Two land-based wind options were considered – one in Kentucky with a 27-31% capacity factor, and one in Indiana with a 39-44% capacity factor.[12] Table 6 shows a comparison of Kentucky and Indiana wind resources and demonstrates that both wind options have significantly higher LCOE compared to utility-scale solar. As a result, solar resources would be added in Kentucky well before wind resources. Because the Kentucky wind option has a lower LCOE compared to Indiana wind, it was evaluated in the Long-Term Resource Planning Analysis.

Table 6: Comparison of Kentucky and Indiana Wind (Nominal Dollars)

Item	2022 Installation		2031 Installation	
	KY Wind	IN Wind	KY Wind	IN Wind
Capital Cost ($/kW)[3]	1,325	1,325	1,143	1,143
Fixed O&M ($/kW-yr)[3]	44.46	44.46	49.03	49.03
Transmission Cost ($/kW-yr)[13]	N/A	87	N/A	104
Capacity Factor[3]	27.4%	39.8%	29.8%	43.1%
Levelized Cost of Energy ($/MWh)	49.79	63.33	43.10	62.25

[12] The Companies used "Class 9" and "Class 6" wind from the 2021 ATB to represent wind resources located in Kentucky and Indiana, respectively.

[13] Transmission cost is based on current firm transmission costs to import power from an Indiana resource.

3 Other Technologies

The following provides an update on technologies that are either not cost-effective or not ideal for utility-scale applications in the Companies' service territories.

3.1 Nuclear

Nuclear power refers to the generation of electricity using a fission reaction, where the nucleus of one atom is split into two or more nuclei, to produce heat which in turn drives a steam turbine to produce electricity. Nuclear generation emits no air pollution including zero CO_2. The United States has just under 100 GW of nuclear fission capacity in operation at this time, with approximately 5% of that capacity expected to retire in 2021.

Small modular reactors ("SMR") and nuclear fusion are two nuclear technologies that are not commercially available but actively being researched. SMR nuclear fission plants are smaller in capacity than modern fission plants and have the advantages of smaller footprints and reduced capital costs. The United States Department of Energy is working to make SMR technology commercially available by the late 2020s to early 2030s. Nuclear fusion refers to the generation of energy by the combining of atoms rather than splitting. While nuclear fusion reactions have been initiated in laboratories, the critical milestone of a self-sustaining reaction, where more energy is released than is consumed, has not been achieved.

Nuclear power has several challenges including high capital costs, inability to ramp up or down quickly to follow load, economic competitiveness within energy markets, permitting, waste disposal, and public perception. At current nuclear capacity cost, which is greater than $7,000/kW, constructing a relatively small 600 MW nuclear plant is expected to cost approximately $4.2 billion. Environmental permitting and waste disposal is a challenge that was partially addressed by Kentucky 17RS SB 11. Kentucky 17RS SB 11 amended KRS 278.600 to require that nuclear power facilities have a plan for the storage of nuclear waste rather than a means of permanent disposal. Previously a federal permanent nuclear waste storage facility was required but with 17RS SB 11, construction of a new nuclear plant is allowed as long as there is a plan for storing the nuclear waste that is approved by the Nuclear Regulatory Commission.

3.2 Combined Cycle with Hydrogen

Hydrogen combined cycle generation would have the significant advantages of being both dispatchable and carbon free. Hydrogen can be produced by renewables and combusted in a turbine without carbon emissions. Over the next decade, research will focus on designing commercial-scale turbines compatible with the combustion characteristics of hydrogen which include higher flame speed and higher temperature, as well as overcoming the high cost of hydrogen as a fuel relative to natural gas. Given those technical and economic challenges, hydrogen combined cycle generation was not evaluated in the Long-Term Resource Planning Analysis. The Companies continue to research hydrogen combined cycle generation because of the important role it could play in decarbonization and renewable integration.

3.3 Natural Gas Combined Cycle without Carbon Capture and Sequestration

NGCC without CCS has the same operating characteristics as NGCC with CCS and its capital and operating costs are significantly lower. However, Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions. SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

3.4 Integrated Gasification Combined-Cycle ("IGCC")

Integrated Gasification Combined-Cycle ("IGCC") technology continues to be developed and is at various stages of commercialization. Only a limited number of IGCC plants have been built and operated around the world, and the cost of these plants have significantly exceeded expectations. For this reason, no IGCC options were evaluated in the Long-Term Resource Planning Analysis.

3.5 Coal-Fired

Because of the high cost of new coal and environmental risk, no coal-fired options were evaluated in the Long-Term Resource Planning Analysis.

3.6 Hydro

The Companies recently upgraded the hydro units on Dix Dam and Ohio Falls, and are not aware of any viable alternatives near their service territories for expanding their portfolio of hydro generation further. For this reason, the hydro option was not evaluated in the Long-Term Resource Planning Analysis.

3.7 Biopower

Due to high capital and operating costs, biopower options were not evaluated in the Long-Term Resource Planning Analysis.

3.8 Reciprocating Engines, Microturbines, and Fuel Cells

Reciprocating internal combustion engines, microturbines, and fuel cells are easily scalable and are well-suited for distributed generation and combined heat and power applications. Reciprocating engines can accommodate both natural gas and fuel oil, and have high efficiency across the ambient range. Reciprocating engines are more popular in areas with high penetrations of renewable generation due to their quick start times and operational flexibility. At present, fuel cells hold little promise for large utility scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development. For these reasons, these options were not evaluated in the Long-Term Resource Planning Analysis.

3.9 Circulating Fluidized Bed

Circulating fluidized bed ("CFB") boilers are a mature coal technology option that is well-suited to burn fuels with a large variability in constituents. Large CFBs require more than one boiler, which increases capital costs but improves unit availability compared to PC technology options. Like PC technology options, CFB are also subject to NSPS for GHG regulations and would require the same CC technology. For these reasons, no CFB option was evaluated in the Long-Term Resource Planning Analysis.

3.10 Waste to Energy

Waste to energy ("WTE") generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Waste fuel is a very diverse category that includes: municipal solid waste, refuse derived fuel, wood chips, landfill gas, sewage, and tire-derived fuel. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. The greatest challenge to building large WTE plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of WTE fuel poses a significant challenge, depending on the size of the facility. Because of these considerations, no WTE options were evaluated in the Long-Term Resource Planning Analysis.

3.11 Concentrating Solar Power

A concentrating solar power ("CSP") option was not evaluated in the Long-Term Resource Planning Analysis because of its high capital costs and infeasibility in the Companies' service territories. The tower and heliostat technology CSP plants that have been built have had serious technical challenges and have performed far worse than expected. Parabolic trough CSP projects have performed better, but remain uneconomic. CSP options are better-suited for sunnier climates, and cost at least four times more than solar PV resources.

2021 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

October 2021

Table of Contents

1 Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, the Companies have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. In past IRPs, the results of this analysis were communicated in the context of a summer peak reserve margin. However, as more solar generation is integrated into the Companies' generation portfolio and included in the calculation of summer reserve margin, a summer reserve margin will have less meaning as an indicator of the portfolio's ability to reliably serve customers in all hours.[1] Therefore, the results of this analysis are communicated in the context of a summer and winter peak reserve margin. The mathematics – like past reserve margin analyses – continue to assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2018 IRP, the 2021 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2025 over a range of generation portfolios with different reserve margins to identify the optimal generation mix for customers.[2] To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirements of one or more Brown 11N2 simple-cycle combustion turbines ("SCCTs"), Mill Creek 2, and Brown 3.[3] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity and solar to the generation portfolio.

The results of the 2021 analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2025. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources; the reliability and generation production cost benefit for each of the Companies' marginal resources exceeds the costs that would be saved by retiring these units. Table 1 compares the 2018 IRP and 2021 IRP summer reserve margin ranges. The minimum of the summer reserve margin range is unchanged, and the maximum of the range in 2021 IRP is slightly lower due primarily to a decrease in the assumed variability of summer peak demands.

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[1] Solar generation is not available to serve the Companies' winter peak, which occurs at night.

[2] 2025 is the first year of the planning period that reflects the planned retirement of Mill Creek 1 and the assumed retirements of the small-frame SCCTs. As the Companies' analyses show, they do not anticipate needing additional generation capacity prior to 2028.

[3] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11. The analysis assumes Mill Creek 1 and the Companies' small-frame SCCTs will be retired by 2025.

Table 1: Summer Target Reserve Margin Ranges

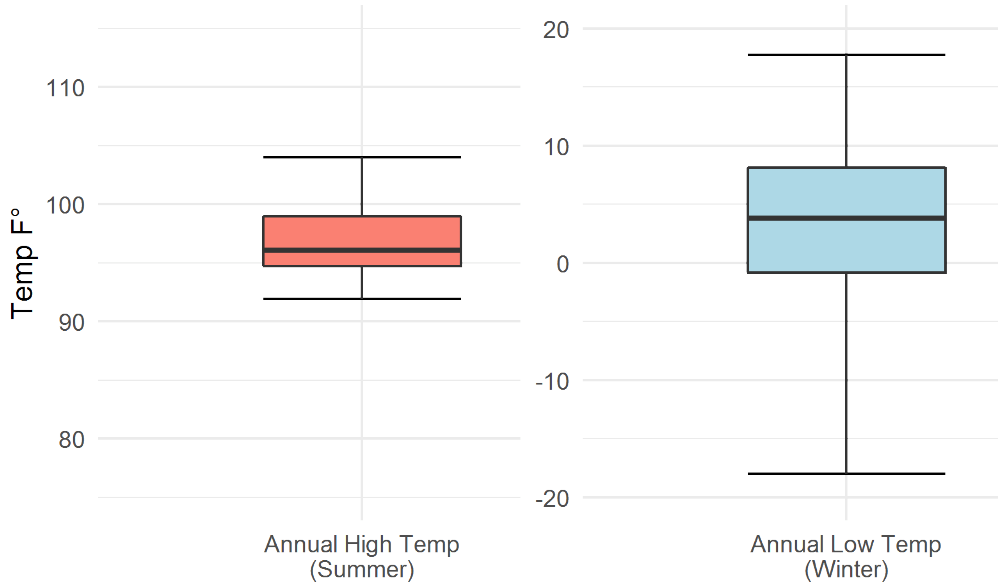
	Summer Range (%)
2018 IRP	17 – 25
2021 IRP	17 – 24

The high end of the 2021 IRP summer reserve margin range (24 percent) is the reserve margin for the generation portfolio that meets the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. The winter reserve margin for the same generation portfolio – computed as a function the forecasted winter peak demand under normal weather conditions – is 35 percent. The low end of the summer reserve margin range is determined by estimating the increase in load that would result in the addition of generation resources. Based on the 2021 IRP analysis, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity if the Companies' load increased by 300 MW. With this load increase, the Companies' summer reserve margin would be approximately 17 percent and the winter reserve margin would be 26 percent. Therefore, the Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.

2 Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Figure 1 shows the distribution of annual high and low temperatures in Louisville over the last 48 years. From 1973 to 2020, the median annual high temperature was 96.1 degrees Fahrenheit and the median annual low temperature was 3.8 degrees Fahrenheit. Additionally, the variability of low temperatures in the winter is significantly greater than the variability of high temperatures in the summer.

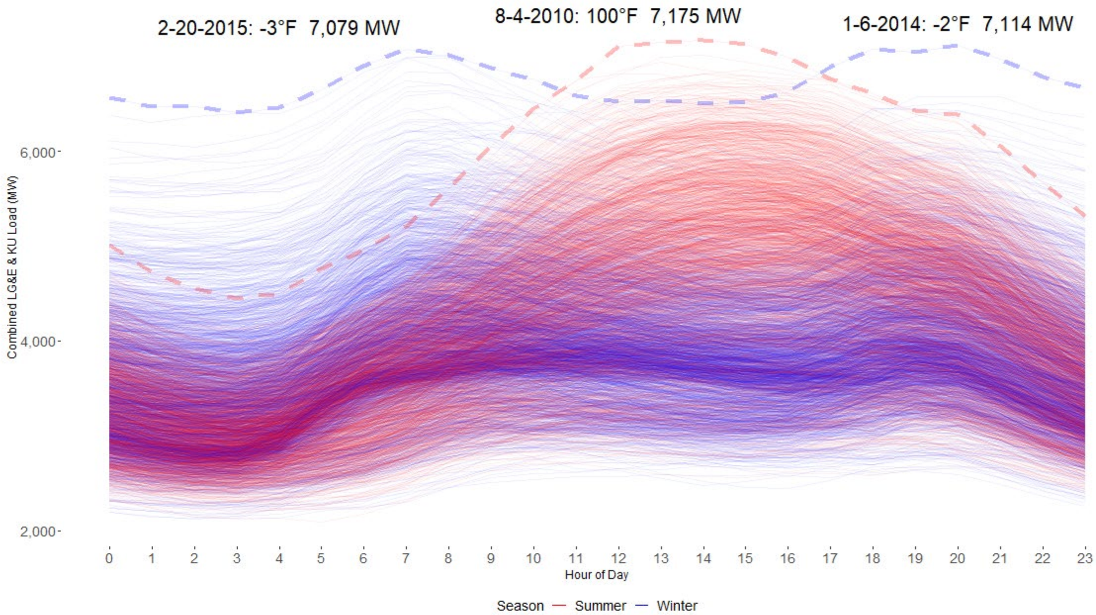
Figure 1: Louisville Annual High and Low Temperature Distributions (1973-2020)[4]



Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015). Figure 2 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

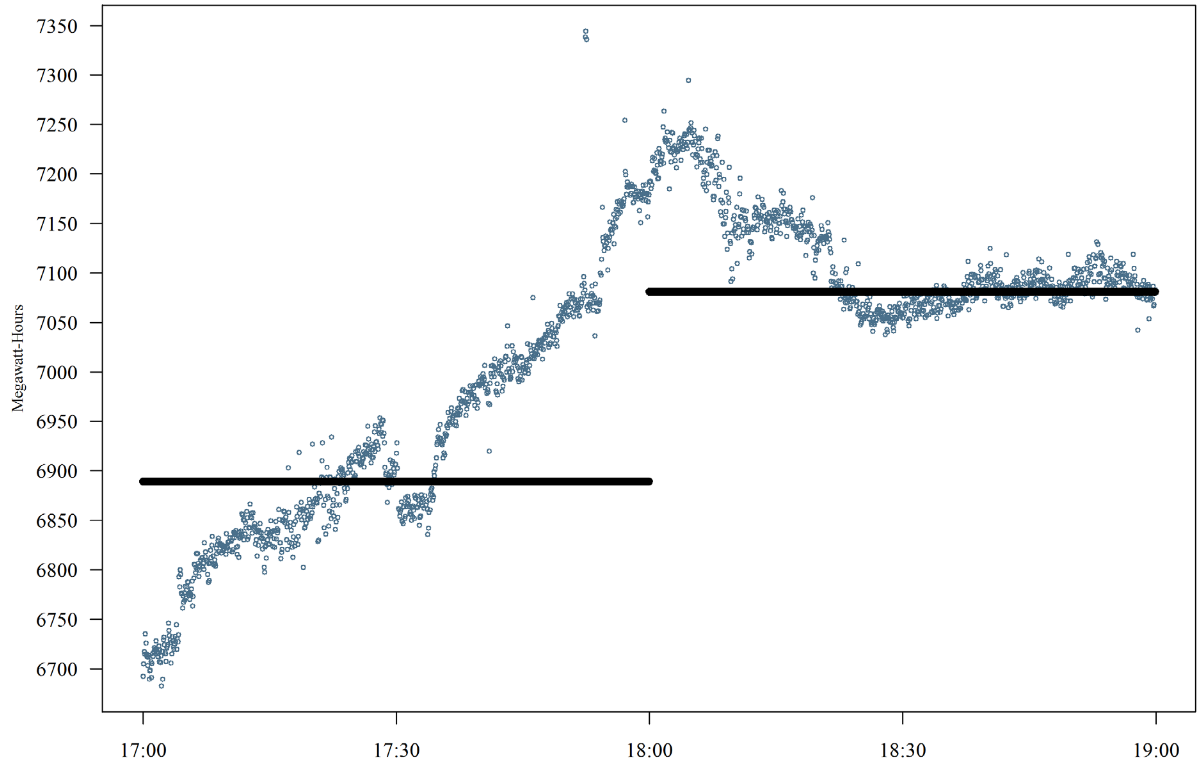
[4] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

Figure 2: Hourly Load Profiles, 2010-2020



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 3 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher.

Figure 3: Four-Second Demands, 5:00-7:00 PM on January 6, 2014



In addition to being reliable, a generation portfolio must possess numerous other attributes to produce power when customers want it. For example, a generation portfolio must possess the ramping capabilities to follow abrupt changes in customers' energy requirements. In addition, the Companies must be able to dispatch at least a significant portion of their generating units when they are needed. Peaking units can start quickly and are needed to respond to unit outages. Baseload units take longer to start, but because their start times are predictable, the Companies can bring them online when they are needed. The size of a resource is also important. If a unit is too big, taking the unit offline for maintenance can be problematic. If a unit is too small, its value in responding to unit outages is limited. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

Customers consume electricity every hour of the year, but no generating resource can be available at all times. Considering the need for maintenance, the Companies' baseload units and large-frame SCCTs are available to be utilized up to 90 percent of hours in a year. The Companies' small-frame SCCTs are over 50 years old and are far less reliable than large-frame SCCTs. The Companies' Curtailable Service Rider ("CSR") limits the ability to curtail participating customers to hours when all large-frame SCCTs have been dispatched. As a result, the ability to utilize this program is limited to, at most, a handful of hours each year.

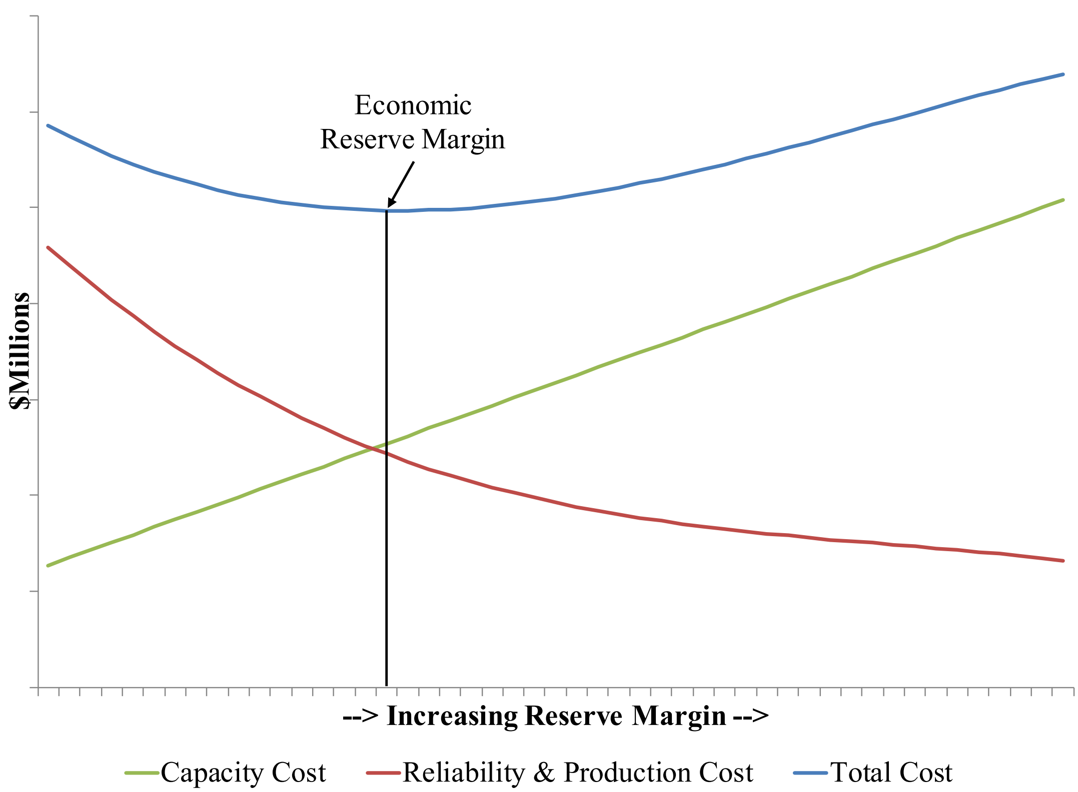
As the Companies evaluate integrating more renewables into their generation portfolio, they must consider the fact that renewables lack many of the characteristics required to serve customers in every moment. Compared to coal- and natural gas-fired resources, the availability of renewables is less predictable and their fuel supply (e.g., sunshine, wind, or water) is more intermittent. Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies' service territories as a source of winter capacity.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

3 Analysis Framework

Figure 4 illustrates the costs and benefits of adding capacity to a generation portfolio.[5] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable), but fixed capacity costs increase. In their reserve margin analysis, the Companies evaluate these costs and benefits over a range of generation portfolios with different reserve margins. The reserve margin for the generation portfolio where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

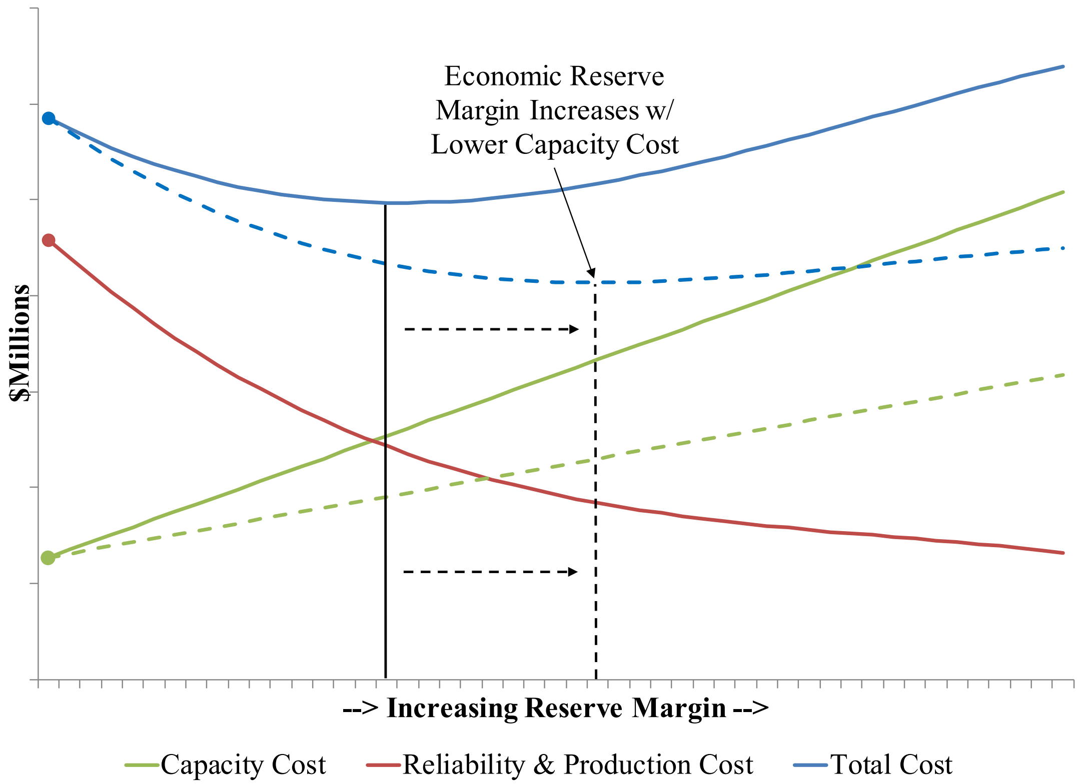
Figure 4: Costs and Benefits of Generation Capacity (Illustrative)



[5] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

Figure 5 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity is reduced to zero.[6]

Figure 5: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit and the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

Table 2 contains the Companies' summer and winter reserve margin forecast for 2025 in the base energy requirements forecast scenario. Generation resources have a higher capacity in the winter primarily because natural gas units can produce more power at lower ambient air temperatures. Mill Creek 1 and

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[6] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

the Companies' small-frame SCCTs are assumed to be retired in 2025. The Rhudes Creek solar facility (100 MW nameplate) is assumed to come online in 2023 and an additional 160 MW of Green Tariff Option 3 solar is added in 2025. None of this capacity is available to serve winter peak because the Companies' winter peak occurs at night. Approximately 79% of the new solar capacity is assumed to be available to serve summer peak.[7]

Table 2: Peak Demand and Resource Summary (MW, Base Energy Requirements Forecast)

	Summer	Winter
Net Peak Load	6,150	5,831
Generation Resources	7,688	7,973
CSR	127	127
DCP	56	0
Retirements/Additions		
Coal[8]	-300	-300
Small-Frame SCCTs[9]	-47	-55
Solar PPAs[10]	204	0
Total Supply	7,728	7,744
Reserve Margin	1,578	1,913
Reserve Margin %	25.7%	32.8%

In 2025, the Companies' forecasted reserve margin is 25.7 percent in the summer and 32.8 percent in the winter. 3.4 percent of the summer reserve margin reflects the assumed availability of the new solar facilities, but the availability of solar is uncertain due to its intermittent fuel source. Figure 6 contains distributions of the average and minimum Brown Solar generation under peak load conditions in June through September. Based on the array's average generation over the hour, between 60 and 88 percent of Brown Solar is available during peak hours.[11] However, based on minimum generation during the hour, between 19 and 56 percent is available. Because the Companies plan generation to serve load in every moment, the distribution of minimum generation is an important consideration and reflects the intermittent nature of solar generation.

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[7] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

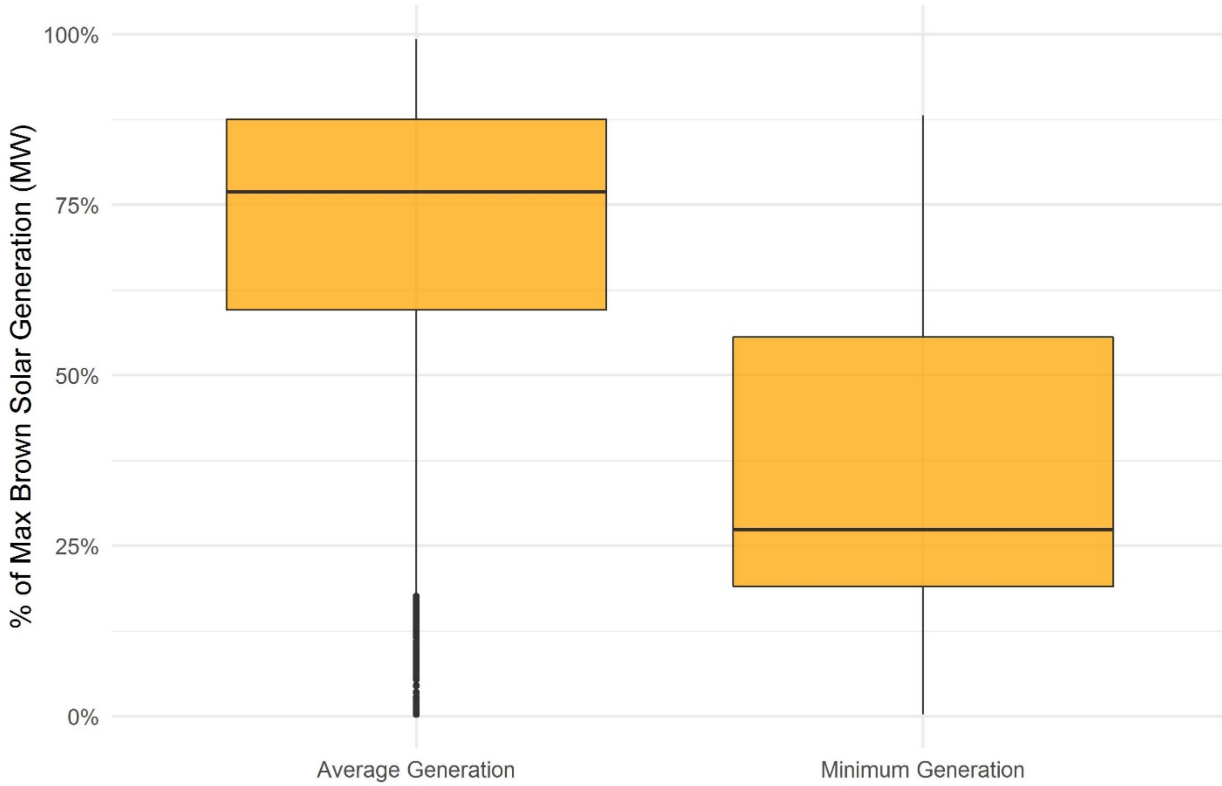
[8] Because Mill Creek 1 and 2 cannot be operated simultaneously during the ozone season due to NOx limits, one of the units (300 MW) is assumed to be unavailable in the summer from 2022 to 2024. Mill Creek 1 is assumed to be retired in 2025.

[9] Haefling 1-2 and Paddy's Run 12 are assumed to be retired in 2025.

[10] Solar PPAs include the Rhudes Creek facility (100 MW nameplate) in 2023 and an additional 160 MW of Green Tariff Option 3 solar in 2025.

[11] 60 and 88 percent are the 25th and 75th percentile values of the distribution.

Figure 6: Distribution of Average and Minimum Brown Solar Generation (June-September; Hours Beginning 1:00 and 2:00 PM EST with System Load > 5,790 MW; 2016-2021)[12]



To evaluate a range of reserve margins, the Companies evaluated the retirement of existing marginal resources and the addition of new resources. In North America, the most commonly used physical reliability guideline is the 1-in-10 LOLE guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs, as well as the expected number of loss-of-load events in ten years ("LOLE"), over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[13] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011, 2014, and 2018 IRPs. SERVM models the availability of generating units in more

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[12] 5,790 MW is the 90th percentile load value for these hours. The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

[13] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

detail than ELDCM, but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2025. 2025 is the first year of the planning period that reflects the planned retirement of Mill Creek 1 and the assumed retirements of the small-frame SCCTs.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[14] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of

[14] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 18% (MISO[15]), 14.8% (PJM[15]), and 17% (TVA[16]).[17]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. From one year to the next, the average availability of generating units is fairly consistent. However, the timing and duration of unplanned outage events in a given year can vary significantly. A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events. Table 3 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[15] See NERC's "2020 Long-Term Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[16] See TVA's "2019 Integrated Resource Plan" at https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan.

[17] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 3: 2025 LG&E/KU Generating & DSM Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW)[18]	Net Max Winter Capacity (MW)	EFOR
Brown 3	Coal	412	416	5.8%
Brown 5	SCCT	130	130	8.1%
Brown 6	SCCT	146	171	8.1%
Brown 7	SCCT	146	171	8.1%
Brown 8	SCCT	121	128	8.1%
Brown 9	SCCT	121	138	8.1%
Brown 10	SCCT	121	138	8.1%
Brown 11	SCCT	121	128	8.1%
Brown Solar	Solar	8	0	2.5%
Cane Run 7	NGCC	662	683	2.2%
Dix Dam 1-3	Hydro	32	32	N/A
Ghent 1	Coal	475	479	3.2%
Ghent 2	Coal	485	486	3.2%
Ghent 3	Coal	481	476	3.2%
Ghent 4	Coal	478	478	3.2%
Mill Creek 2	Coal	297	297	3.2%
Mill Creek 3	Coal	391	394	3.2%
Mill Creek 4	Coal	477	486	3.2%
Ohio Falls 1-8	Hydro	64	40	N/A
OVEC-KU	Power Purchase	47	49	N/A
OVEC-LG&E	Power Purchase	105	109	N/A
Paddy's Run 13	SCCT	147	175	8.1%
Trimble County 1 (75%)	Coal	370	370	3.2%
Trimble County 2 (75%)	Coal	549	570	5.1%
Trimble County 5	SCCT	159	179	4.9%
Trimble County 6	SCCT	159	179	4.9%
Trimble County 7	SCCT	159	179	4.9%
Trimble County 8	SCCT	159	179	4.9%
Trimble County 9	SCCT	159	179	4.9%
Trimble County 10	SCCT	159	179	4.9%
Business Solar	Solar	0.2	0	2.5%
Solar Share	Solar	1.3	0	2.5%
Rhudes Creek Solar	Solar	79	0	2.5%
Additional GT Option 3 Solar	Solar	126	0	2.5%
CSR	Interruptible	127	127	N/A
DCP[19]	DSM	56	0	N/A

[18] Projected net ratings as of 2022. OVEC's capacity reflects the capacity that is expected to be available to the Companies at the time of the summer and winter peaks. The ratings for Brown Solar, Business Solar, Solar Share, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer and winter peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

[19] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 4 and Table 5. Fuel prices in neighboring regions were assumed to be consistent with the Companies' fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 4: 2025 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	[redacted]
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	

Table 5: 2025 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	[redacted]
Ghent	
Mill Creek	
Trimble County – High Sulfur	
Trimble County – PRB	

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 6 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[20] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 127 MW.

[20] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 6: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system and the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 7 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 42% of the time.

Table 7: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	98	42%
1 – 199	2	1%
200 - 399	10	4%
400 - 599	17	7%
600 - 799	11	5%
800 - 999	21	9%
>= 1,000	73	31%
Total	232	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 8 summarizes the summer peak demand forecast for the Companies' service territories and neighboring regions in 2025. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 8: Peak Load Forecasts for 2025

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,150	20,186	34,288	30,170
Target Reserve Margin	N/A	18.0%	14.8%	17%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 48 hourly demand forecasts for 2025 based on actual weather in each of the last 48 years.

Table 9 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions based on these "weather year" forecasts. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated. Because the ability to purchase power from neighboring regions often depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions.

Table 9: Summer and Winter Peak Demand Forecasts, 2025

LG&E/ KU Load	Summer					Winter				
			Coincident Peak Demand in Neighboring Regions					Coincident Peak Demand in Neighboring Regions		
	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA
Max	1983	6,985	20,790	35,110	31,017	1985	7,357	19,181	38,086	36,106
75th %-ile	1995	6,336	20,688	34,740	29,716	1978	6,392	16,984	32,094	30,782
Median	2016	6,043	18,296	30,939	27,248	2011	5,942	18,455	33,416	27,484
25th %-ile	1981	5,882	18,450	30,703	28,514	1987	5,666	18,040	32,521	29,953
Min	1974	5,660	18,208	30,531	23,916	1998	5,187	12,483	26,885	21,713

Figure 7 and Figure 8 contain graphical distributions of the Companies' summer and winter peak demands for 2025. The values in Figure 7 labeled "Forecasted Peak" (i.e., 6,150 MW in the summer and 5,831 MW in the winter) are the Companies' forecasts of summer and winter peak based on average peak weather conditions over the past 20 years. In Figure 8, the year labels indicate the weather years on which the seasonal peaks are based. The Companies' Forecasted Peak is higher in the summer, but the variability in peak demands is much higher in the winter.[21] This is largely due to the wider range of low temperatures that can be experienced in the winter and the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[21] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 127 MW in 2025. The maximum winter peak demand (7,357 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 7: Distributions of Summer and Winter Peak Demands, 2025

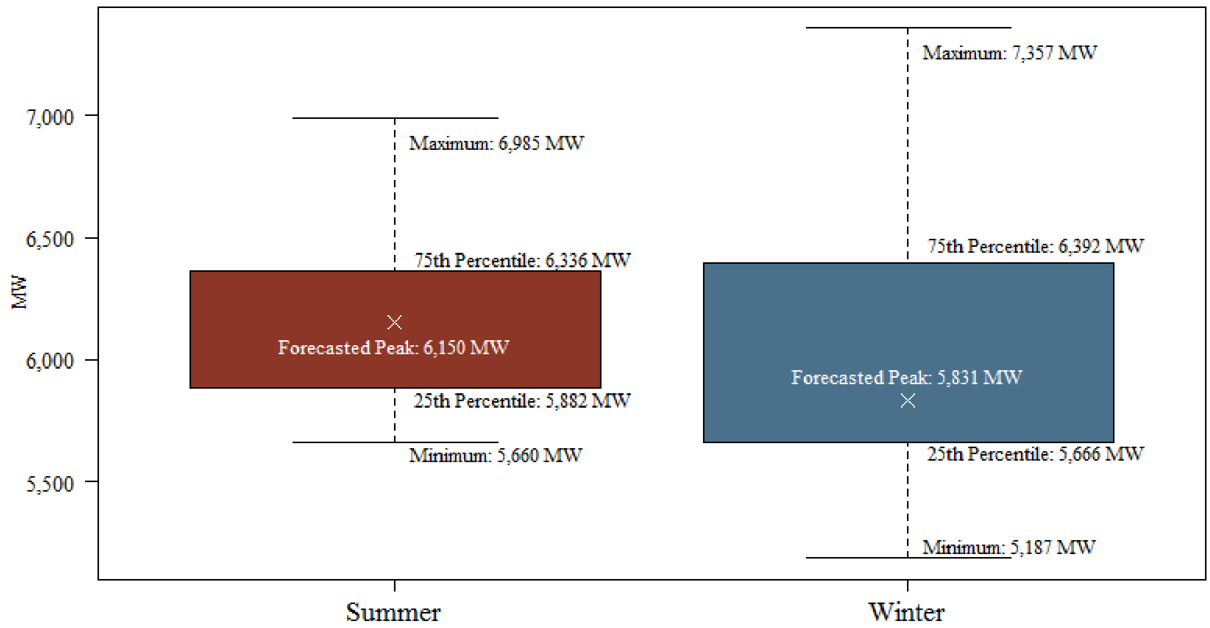
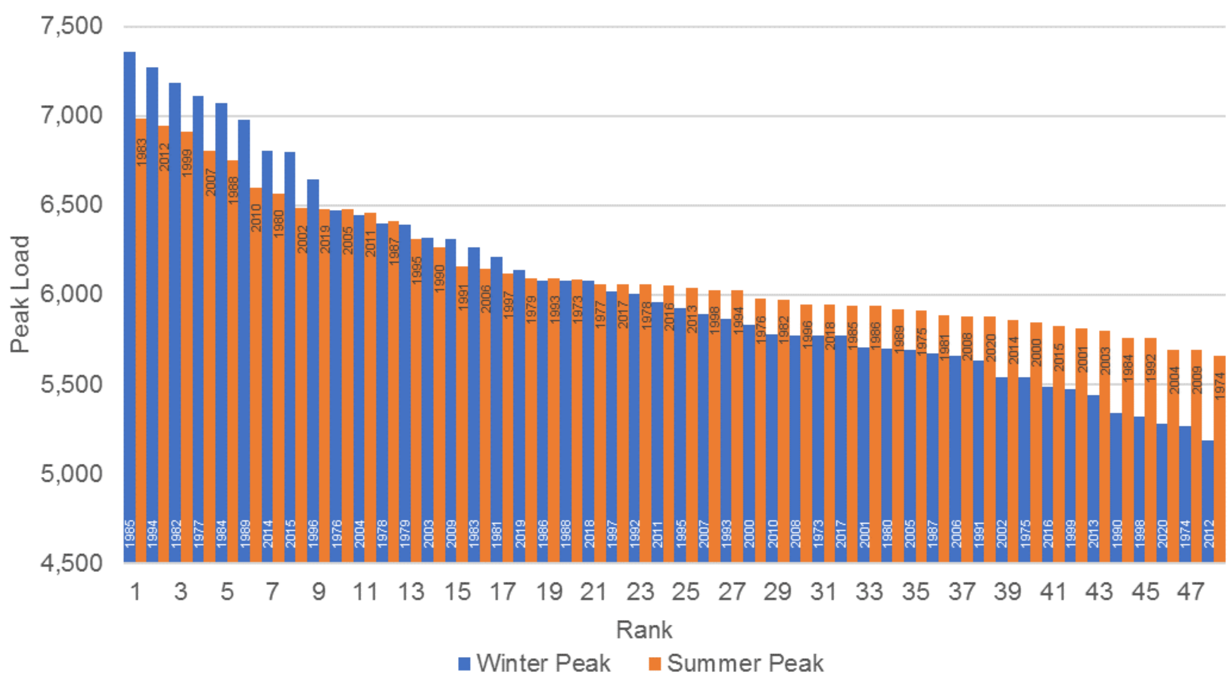


Figure 8: Distributions of Summer and Winter Peak Demands, 2025



4.6 Marginal Resource Costs

Table 10 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, and the Companies' peaking units that are 15 or more years old. The Companies' peaking units include large-frame SCCTs at the Brown, Paddy's Run, and Trimble County stations. The stay-open costs in Table 10 are presented in 2025 dollars. Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 10: Marginal Resource Costs (2025 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.4	27	63
	Ghent 1	72.2	23	36
	Ghent 2	40.9	22	29
	Ghent 3	92.3	23	42
	Mill Creek 2	62.9	22	31
	Mill Creek 3	105.0	23	40
Peaking	Brown 5, 8, 9, 10, & 11	6.0	41	72
	Brown 6 & 7	8.2	29	45
	Paddy's Run 13	21.5	33	57
	Trimble County 5-10	16.1	30	48

To evaluate generation portfolios with lower reserve margins, the sum of stay-open and average energy costs in Table 10 was used to determine which baseload and peaking resources to consider for retirement. For example, based on these costs, the Companies evaluated the retirements of the Brown SCCTs and Brown 3. The retirement of Mill Creek 2 was also evaluated due to its likely need for SCR. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[22]

To evaluate generation portfolios with higher reserve margins, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2021 IRP Resource Screening Analysis and is summarized in Table 11 in 2025 dollars.

[22] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

Table 11: SCCT Cost (2025 Dollars)[23]

Input Assumption	Value
Capital Cost ($/kW)	907
Fixed O&M ($/kW-yr)	23.5
Firm Gas Transport ($/kW-yr)	22.2
Escalation Rate	1.42%
Discount Rate	6.41%
Carrying Charge ($/kW-yr)	112.7

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[24] All studies split customers into residential, commercial, and industrial classes, which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2025 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $19.8/kWh.

Table 12 shows how the numbers were derived. The range for residential customers varied from $1.5/kWh to $3.8/kWh. The range for commercial customers varied from $26.8/kWh to $39.6/kWh while industrial customers varied from $13.9/kWh to $32.2/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $8.0/kWh.

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[23] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[24] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

Table 12: Cost of Unserved Energy (2025 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.7	1.5	3.8	3.2
Commercial	36%	39.6	36.1	26.8	27.8
Industrial	30%	22.9	32.2	13.9	27.8
System Cost of Unserved Energy		21.7	23.1	15.1	19.4
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.5	2.6	3.8	2.3
Commercial	36%	26.8	32.6	39.6	12.9
Industrial	30%	13.9	24.2	32.2	18.3
Average System Cost of Unserved Energy			19.8		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 252 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

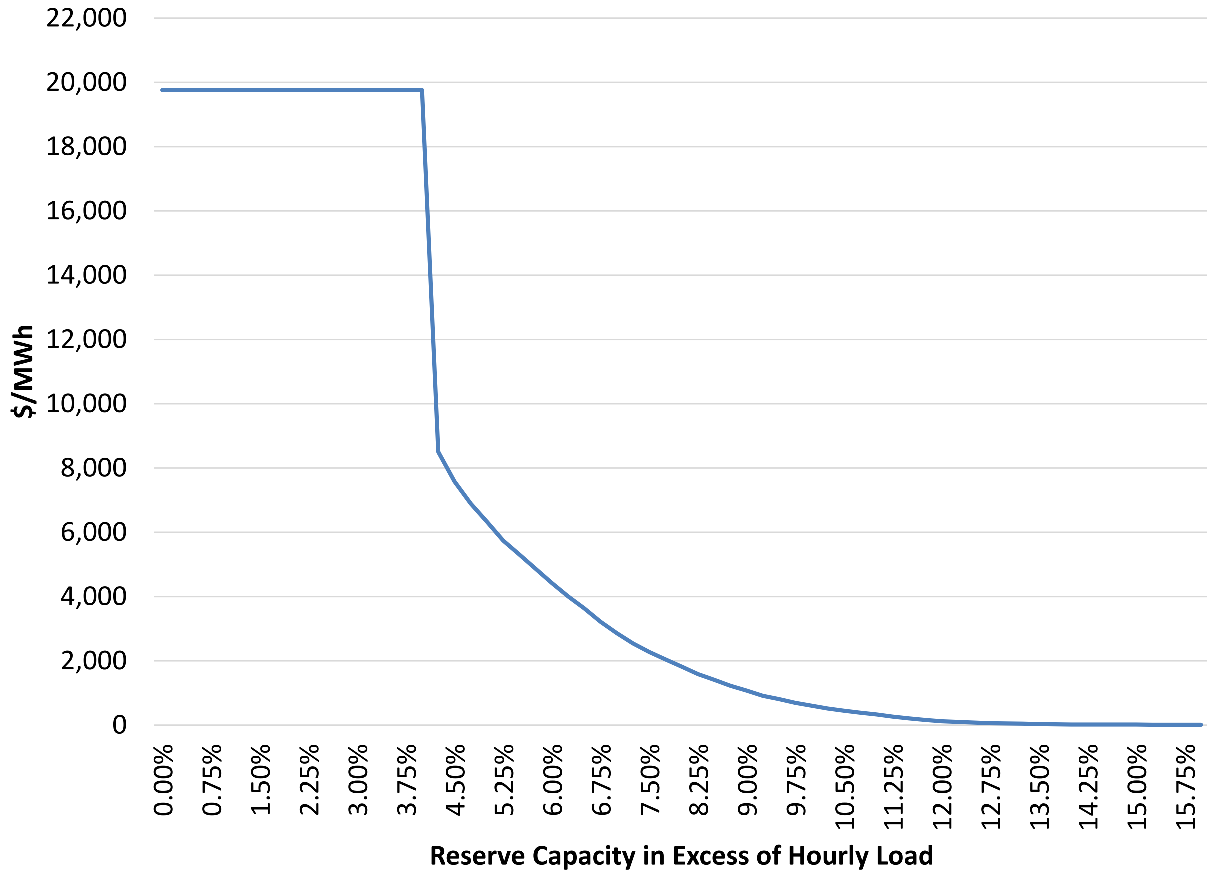
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 252 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 9 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (252 MW) is approximately 4.0% of the forecasted summer peak demand in 2025 (6,150 MW). At reserve capacities less than 4.0% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($19,800/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 9: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value ($100/MWh). Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5 Analysis Results

5.1 Economic Reserve Margin and 1-in-10 LOLE Guideline

Consistent with the methodology used in the 2018 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs over a range of reserve margins to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of their existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity.

The generation portfolios evaluated in this analysis are described in Table 13. As discussed previously, 260 MW of new solar is assumed to come online by 2025, but the availability of the new resources during summer peak is uncertain (see discussion pertaining to Figure 6).[25] For this reason, the Companies first evaluated target reserve margin ranges without the new solar resources.

Table 13: Generation Portfolios Considered in Reserve Margin Analysis

		Summer Reserve Margin		Winter Reserve Margin	
Generation Portfolio	**Portfolio Abbreviation**	**w/o New Solar**	**w/ New Solar**	**w/o New Solar**	**w/ New Solar**
Existing + 140 MW SCCT	Add SCCT2	24.6%	27.9%	35.2%	35.2%
Existing + 70 MW of SCCT	Add SCCT1	23.5%	26.8%	34.0%	34.0%
Existing[26]	Existing	22.3%	25.7%	32.8%	32.8%
Retire Brown 8	Ret B8	20.3%	23.7%	30.6%	30.6%
Retire Brown 8-9	Ret B8-9	18.4%	21.7%	28.6%	28.6%
Retire Mill Creek 2	Ret M2	17.5%	20.8%	27.7%	27.7%
Retire Brown 8-10	Ret B8-10	16.4%	19.8%	26.2%	26.2%
Retire Brown 3	Ret B3	15.6%	19.0%	25.7%	25.7%
Retire Brown 8-11	Ret B8-11	14.4%	17.8%	24.0%	24.0%
Retire Brown 3, Mill Creek 2	Ret B3_M2	10.8%	14.1%	20.6%	20.6%

LOLE and reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 13 over 48 weather year scenarios and hundreds of unit availability scenarios. For each portfolio without the new solar resources, Table 14 contains the average summer, winter, and total LOLE from ELDCM, as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 15.

Portfolios with LOLE greater than four (i.e., four times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3_M2 portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85th and 90th percentiles ("%-ile") of the reliability and generation production cost distribution.

[25] 260 MW is the sum of capacity for Rhudes Creek Solar (100 MW) and 160 MW of additional Green Tariff Option 3 solar. On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

[26] Existing portfolio excludes Mill Creek 1 and the Companies's small-frame SCCTs, which are assumed to be retired by 2025.

Table 14: Reserve Margin Analysis Results without New Solar (ELDCM, 2025 Dollars)

Generation Portfolio	Loss of Load Events			[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
	Sum	Win	Total		[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.49	0.29	0.79	63.9	754	768	772	818	832	835
Add SCCT1	0.65	0.37	1.04	56.0	754	769	773	810	825	829
Existing	0.86	0.47	1.36	48.1	755	771	775	803	819	824
Ret B8	1.36	0.70	2.11	47.3	758	772	784	805	819	832
Ret B8-9	2.12	0.99	3.19	46.6	761	780	792	808	827	838
Ret M2	2.73	1.20	4.04	29.4	769	792	802	798	822	832
Ret B8-10	3.27	1.47	4.87	45.9	766	793	802	812	839	848
Ret B3	3.77	1.59	5.52	18.7	767	797	808	786	815	827
Ret B8-11	4.98	2.08	7.27	45.1	774	811	824	819	856	870
Ret B3_M2	10.75	3.59	14.87	0.0	803	869	893	803	869	893

Table 15: Reserve Margin Analysis Results without New Solar (SERVM, 2025 Dollars)

Generation Portfolio	Loss of Load Events			[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
	Sum	Win	Total		[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.34	0.25	0.76	63.9	734	757	757	798	820	821
Add SCCT1	0.48	0.33	1.04	56.0	734	755	758	790	811	814
Existing	0.63	0.46	1.42	48.1	735	755	759	783	803	808
Ret B8	0.98	0.69	2.26	47.3	735	757	763	783	805	811
Ret B8-9	1.57	1.03	3.71	46.6	739	763	772	786	810	819
Ret M2	2.14	1.17	4.75	29.4	751	778	789	780	807	818
Ret B8-10	2.38	1.53	5.74	45.9	744	773	784	790	819	830
Ret B3	3.78	1.69	8.05	18.7	752	786	797	771	805	816
Ret B8-11	3.54	2.13	8.64	45.1	752	789	802	797	834	847
Ret B3_M2	10.95	3.57	23.08	0.0	800	858	891	800	858	891

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Approximately one-third of the Companies' total LOLE is associated with serving load in the winter months. With no new solar, the Add SCCT1 generation portfolio (23.5 percent summer reserve margin; 34.0 percent winter reserve margin) has an LOLE slightly greater than one and the Add SCCT2 generation portfolio (24.6 percent summer reserve margin; 35.2 percent winter reserve margin) has an LOLE less than one. Therefore, the summer reserve margin required to meet the 1-in-10 physically reliability standard is approximately 24 percent and the corresponding winter reserve margin is approximately 35 percent. Furthermore, considering the portfolios with an LOLE less than four, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution, the Existing portfolio has the lowest total cost.

Consistent with the 2018 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3 portfolio are $12 million to $17 million higher, but the Companies would expect these costs to be $33 million to $38 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is more reliable and reliability and generation production costs are less volatile.

The ELDCM was used to evaluate the impact of adding 260 MW of nameplate solar to the generation portfolios with the assumption that 79 percent of the capacity would be available to serve summer peak. The results of this analysis are summarized in Table 16. Comparing Table 16 to Table 14, not surprisingly, adding solar to the generation portfolio has a significant impact on LOLE in the summer but not in the winter; approximately one-half (versus one-third) of the Companies' total LOLE is associated with serving load in the winter months.

Table 16: Reserve Margin Analysis Results with New Solar (ELDCM, 2025 Dollars)

	Loss of Load Events				Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
Generation Portfolio	Sum	Win	Total	[A] Capacity Cost ($M/year)	[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	0.20	0.25	0.46	63.9	737	753	755	801	817	819
Add SCCT1	0.27	0.32	0.60	56.0	738	753	755	794	809	811
Existing	0.37	0.41	0.79	48.1	738	754	756	786	802	804
Ret B8	0.60	0.62	1.24	47.3	740	755	760	787	803	808
Ret B8-9	0.97	0.89	1.89	46.6	742	757	766	788	803	812
Ret M2	1.26	1.07	2.38	29.4	748	767	774	777	796	803
Ret B8-10	1.52	1.32	2.91	45.9	745	769	771	791	815	817
Ret B3	1.75	1.43	3.26	18.7	745	770	772	763	789	791
Ret B8-11	2.38	1.88	4.37	45.1	750	776	788	795	821	833
Ret B3_M2	5.43	3.27	8.96	0.0	768	814	838	768	814	838

If 79 percent of the additional solar capacity is available to serve summer peak, retiring Brown 3 without replacement and assuming more reliability risk – particularly in the witner – will result in slightly lower costs for customers.[27] In addition, the new solar would increase the maximum of the summer reserve margin range from 24 to 25 percent and decrease the maximum of the winter reserve margin range from 35 to 32 percent.[28] However, because the availability of solar under peak load conditions can be much lower than 79 percent (see Figure 6 on page 11), the Companies plan to carefully evaluate the moment-to-moment availability of the Rhudes Creek solar facility before making any further changes to their generation portfolio or their summer and witner target reserve margin ranges.

5.2 Target Reserve Margin Range

The high end of the Companies' target reserve margin range is the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. As discussed above and ignoring for now the potential reliability impacts of new solar generation, the generation portfolio required to meet this guideline has a summer reserve margin of 24 percent and a winter reserve margin of 35 percent.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads. The results of this analysis from ELDCM and SERVM are summarized in Table 17 and Table 18, respectively. Consistent with the 2018 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 14 and Table 15. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 MW (i.e., summer reserve margin decreases to 17 percent and witner reserve margin decreases to 26 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

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[27] Considering the portfolios with an LOLE less than four, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution, the "Ret B3" portfolio has a slightly lower total cost than the "Existing" portfolio.

[28] With the additional solar resources, the Existing generaton portfolio (25.7 percent summer reserve margin; 32.8 percent winter reserve margin) has an LOLE less than one and the Ret B8 portfolio (23.7 percent summer reserve margin; 30.6 percent winter reserve margin) has an LOLE greater than one.

Table 17: Minimum of Target Reserve Margin Range (ELDCM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	22.3%	32.8%	819	825	7	824	829	5
50	21.3%	31.7%	830	837	7	838	841	3
100	20.4%	30.6%	841	848	7	853	855	3
150	19.4%	29.5%	855	860	5	868	870	2
200	18.5%	28.4%	870	872	2	882	885	3
250	17.5%	27.3%	885	888	3	896	900	4
300	16.6%	26.3%	902	901	(1)	911	914	3
350	15.7%	25.3%	920	919	(1)	929	929	(0)
400	14.9%	24.3%	938	936	(2)	950	945	(5)

Table 18: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	22.3%	32.8%	803	811	8	808	814	6
50	21.3%	31.7%	819	824	4	821	827	6
100	20.4%	30.6%	830	838	8	834	840	6
150	19.4%	29.5%	842	849	7	848	853	6
200	18.5%	28.4%	856	861	5	867	867	1
250	17.5%	27.3%	867	873	5	880	884	4
300	16.6%	26.3%	890	889	(1)	897	899	3
350	15.7%	25.3%	912	905	(7)	919	915	(4)
400	14.9%	24.3%	927	918	(9)	931	934	3

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are highly uncertain and hard-to-quantify, the Companies evaluated several sensitivities to the base case inputs. The inputs chosen for sensitivity analysis include cost of unserved enery, scarcity prices, EFOR, and available tranmssion capacity (ATC). The Companies used ELDCM to determine the least-cost generation potfolio for each sensitivity by varying those inputs one at a time.

The base case input for the cost of unserved energy is $19,800/MWh, which is based on information from publicly available studies. The cost of unserved energy is hard to quantify because it varies by customer class. Therefore, the Companies evaluated high and low costs of unserved energy by varying the base assumption by approximately 25 percent. The base case input for scarcity price in ELDCM is $100/MWh, which is difficult to specify because it is a function of reserve capacity determined by unit availability and load. To understand the impact of this input on the analysis, the Companies evaluated significantly higher and lower scarcity prices. As seen in Table 3, the base case inputs for EFOR range from 3.2% for coal baseload units to 8.1% for the Brown SCCTs, and are based on averages from multiple years of history. Historically, EFOR has varied from one year to the next. For the sensitivities, the Companies increased and decreased EFOR by 1.5% and 1%, respectively. For example, the High EFOR case has EFOR ranging from 4.7% for coal baseload units to 9.6% for Brown SCCTs. In the base case, the analysis assumes 500 MW of transmission capacity is available two-thirds of the time, which is based on daily ATC on weekdays during the summer and winter months in 2019-2021. As shown in Table 7, the distribution for ATC has a wide range. For the sensitivities, the Companies decreased and increased ATC to 0 and 1000 MW, respectively.

Table 19 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than four. The results demonstrate that the existing portfolio has the lowest total cost under different assumptions for the highly uncertain and hard-to-quantify inputs, when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution.

Table 19: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	**85th Percentile**	**90th Percentile**
Base Case	Existing	Existing
Cost of Unserved Energy		
High Cost of Unserved Energy ($25,000/MWh)	Existing	Existing
Low Cost of Unserved Energy ($15,000/MWh)	Existing	Existing
Scarcity Prices		
High Scarcity Prices ($500/MWh)	Existing	Existing
Low Scarcity Prices ($50/MWh)	Existing	Existing
Unit Availability		
High EFOR: Increase EFOR by 1.5 Points	Existing	Existing
Low EFOR: Decrease EFOR by 1.0 Points	Existing	Existing
Available Transmission Capacity		
No Access to Neighboring Markets	Existing	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Existing	Existing

5.4 Final Recommendation

All other things equal, if the Companies' load increases by approximately 300 MW (i.e., summer reserve margin decreases to 17 percent and winter reserve margin decreases to 26 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 24 percent in the summer and 35 percent in the winter. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a summer reserve margin range of 17 to 24 percent and a winter reserve margin range of 26 to 35 percent for resource planning.

2021 IRP Long-Term Resource Planning Analysis

PPL companies

Generation Planning & Analysis

October 2021

Table of Contents

1 Executive Summary

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans over a range of forecasted energy requirements and fuel prices.

Table 1 lists the generating units that are assumed to retire during the 15-year IRP planning period (2022-2036). Mill Creek 1 will be retired in 2024 as part of the Companies' least-cost plan for complying with the amended Effluent Limit Guidelines. Due to their age and inefficiency, the Companies' remaining small-frame SCCTs (Haefling 1-2 and Paddy's Run 12) are assumed to retire by 2025. Consistent with the analysis summarized in Case Nos. 2020-00349 and 2020-00350, Mill Creek 2 and Brown 3 are assumed to retire in 2028. The retirement year for each of the remaining units in Table 1 is the end of the unit's book depreciation life.

Table 1: Assumed Unit Retirement Dates

Unit(s)	Assumed Retirement Year
Mill Creek 1	2024
Haefling 1-2, Paddy's Run 12	2025
Mill Creek 2, Brown 3	2028
Ghent 1-2, Brown 9	2034
Brown 8 and 10	2035
Brown 11	2036

Table 2 lists the Companies' forecasted summer and winter reserve margins in the base, high, and low energy requirements ("load") forecast scenarios and reflects the assumed retirements in Table 1 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[1] The target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.

[1] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Table 2: Forecasted Summer and Winter Reserve Margins[2]

Year	Base Load Scenario		High Load Scenario		Low Load Scenario	
	Summer	Winter	Summer	Winter	Summer	Winter
2022	21.6%	37.3%	21.6%	37.3%	22.7%	38.7%
2023	23.4%	37.9%	23.3%	37.9%	24.8%	39.6%
2024	23.8%	38.2%	22.1%	34.3%	27.0%	42.3%
2025	25.7%	32.8%	23.7%	26.5%	29.3%	36.9%
2026	26.4%	33.4%	22.8%	23.2%	32.1%	39.9%
2027	26.9%	33.8%	23.0%	21.1%	33.2%	40.8%
2028	15.6%	21.7%	11.9%	8.3%	22.4%	28.5%
2029	15.8%	22.1%	11.8%	6.7%	25.2%	29.2%
2030	15.8%	22.3%	11.7%	3.9%	26.0%	29.5%
2031	16.2%	22.6%	11.4%	2.6%	28.8%	30.3%
2032	16.2%	22.5%	11.1%	1.0%	28.7%	30.3%
2033	16.3%	22.8%	11.0%	-0.6%	30.7%	31.0%
2034	-1.6%	3.7%	-6.4%	-17.8%	10.5%	11.3%
2035	-5.6%	-1.0%	-10.5%	-22.8%	6.0%	6.1%
2036	-7.7%	-3.5%	-12.8%	-27.6%	4.5%	3.2%

Table 3 lists total new generation in the least-cost resource plans from this analysis; the timing of new generation additions is summarized in Section 4.3. In the base and low load scenarios, capacity additions are driven by the need to replace retired capacity. In the high load scenario, capacity additions are also needed to serve the increasing load, particularly in the witner months. For example, compared to the Base load scenario, the additional SCCTs, solar, and battery storage in the High load scenario are needed to serve the higher load. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions. The analysis also considered the capital revenue requirements and fixed costs associated with these plans. The least-cost resource plan for each case was identified as the plan with the lowest present value of revenue requirements ("PVRR").

[2] Values reflect the assumed retirements in Table 1 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.

Table 3: New Generation in Least-Cost Resource Plans

Years	Load Scenario	Fuel Price Scenario	Gas	Solar	Wind	Batteries
2026-2030	Base	Base	2 SCCTs[3]	500 MW	0 MW	0 MW
		High	2 SCCTs	1,000 MW	0 MW	0 MW
		Low	2 SCCTs	300 MW	0 MW	0 MW
	High	Base	6 SCCTs	1,500 MW	0 MW	100 MW
		High	5 SCCTs	1,500 MW	0 MW	300 MW
		Low	7 SCCTs	500 MW	0 MW	0 MW
	Low	Base	0 SCCTs	500 MW	0 MW	0 MW
		High	0 SCCTs	1,000 MW	0 MW	0 MW
		Low	0 SCCTs	0 MW	0 MW	0 MW
2031-2036	Base	Base	4 SCCTs	1,600 MW	0 MW	200 MW
		High	0 SCCTs	2,400 MW	300 MW	1,100 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW
	High	Base	0 SCCTs	2,400 MW	100 MW	2,500 MW
		High	0 SCCTs	2,200 MW	1,900 MW	2,000 MW
		Low	10 SCCTs	600 MW	0 MW	0 MW
	Low	Base	4 SCCTs	700 MW	100 MW	200 MW
		High	2 SCCTs	1,600 MW	100 MW	700 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW

Despite a wide range of load and fuel scenarios, some consistent results emerged. Solar and SCCTs are the predominate resource technology choices until the retirement of Ghent 1 and Ghent 2 in 2034. Battery storage is favored in cases with high renewable penetration. The replacement of Ghent 1 and Ghent 2 is expected to rely on renewable resources for energy in most scenarios, and either SCCTs or battery storage for capacity. And NGCC with CCS is not cost-competitive with solar combined with SCCTs or battery storage in any of the scenarios modeled in this analysis. In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors. Successful deployment of Demand-Side Management ("DSM") programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource planning analysis represents the Companies' analysis of the best options to meet customer needs at this point in time, this plan is reviewed, re-evaluated, and assessed against other market-available alternatives prior to commitment and implementation.

[3] A SCCT is assumed to have a summer capacity of 220 MW and a winter capacity of 248 MW.

2 Resource Planning Objectives

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans over a range of forecasted load and fuel prices. These inputs and uncertainties are discussed in the following section.

For each load and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period. The analysis considered all costs for new and existing resources, and it optimized the portfolio to minimize energy and new capacity costs. An annual resource plan was then developed for each case to meet minimum reserve margin requirements (i.e., 17 percent in the summer and 26 percent in the winter) throughout the planning period. The PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base load, base fuel case.

3 Key Inputs and Uncertainties

The following sections summarize key resource planning inputs and uncertainties.

3.1 Load Forecast

The Companies' base, high, and low load forecasts are summarized in Table 4. Table 5 summarizes the base, high, and low forecasts for summer and winter peak demands. The development of these forecasts is discussed in Section 5.(2) and Section 5.(3) in Volume I. A key consideration in resource planning is ensuring reliable service to customers in both summer and winter months.

Table 4: Load Forecast (GWh)

Year	Base	High	Low
2022	32,238	32,271	31,939
2023	32,079	32,152	31,719
2024	32,045	32,980	30,951
2025	31,839	33,039	30,702
2026	31,648	33,816	29,788
2027	31,532	34,019	29,595
2028	31,519	34,387	29,427
2029	31,370	34,651	28,980
2030	31,279	35,036	28,549
2031	31,243	35,425	28,444
2032	31,283	35,968	28,353
2033	31,196	36,358	28,144
2034	31,172	36,866	28,043
2035	31,188	37,368	28,005
2036	31,289	38,001	28,064

Table 5: Peak Demand Forecasts (MW)

Year	Summer			Winter		
	Base	High	Low	Base	High	Low
2022	6,229	6,230	6,175	5,898	5,899	5,839
2023	6,201	6,204	6,134	5,874	5,875	5,804
2024	6,179	6,265	6,024	5,859	6,030	5,693
2025	6,150	6,248	5,975	5,831	6,120	5,656
2026	6,113	6,294	5,849	5,806	6,287	5,535
2027	6,088	6,283	5,800	5,790	6,395	5,502
2028	6,067	6,270	5,731	5,777	6,494	5,472
2029	6,055	6,271	5,602	5,758	6,590	5,444
2030	6,056	6,280	5,564	5,750	6,769	5,430
2031	6,033	6,291	5,445	5,736	6,854	5,395
2032	6,035	6,312	5,448	5,738	6,961	5,395
2033	6,029	6,315	5,362	5,726	7,076	5,367
2034	6,020	6,330	5,364	5,715	7,211	5,325
2035	6,023	6,350	5,361	5,719	7,334	5,337
2036	6,026	6,379	5,321	5,737	7,648	5,364

3.2 Existing Generation Specifications

Table 6 lists the assumed net summer and winter capacity ratings for each of the Companies' existing generating resources.[4]

[4] The Companies expect to retire Zorn 1 by the end of 2021.

Table 6: Existing Generating Resource Characteristics

Resource	Net Max Summer Rating (MW)[5]	Net Max Winter Rating (MW)
Brown 3	412	416
Brown 5	130	130
Brown 6	146	171
Brown 7	146	171
Brown 8	121	128
Brown 9	121	138
Brown 10	121	138
Brown 11	121	128
Brown Solar	8	0
Cane Run 7	662	683
Dix Dam 1-3	32	32
Ghent 1	475	479
Ghent 2	485	486
Ghent 3	481	476
Ghent 4	478	478
Haefling 1-2	24	27
Mill Creek 1	300	300
Mill Creek 2	297	297
Mill Creek 3	391	394
Mill Creek 4	477	486
Ohio Falls 1-8	64	40
OVEC-KU	47	49
OVEC-LG&E	105	109
Paddy's Run 12	23	28
Paddy's Run 13	147	175
Trimble County 1 (75%)	370	370
Trimble County 2 (75%)	549	570
Trimble County 5	159	179
Trimble County 6	159	179
Trimble County 7	159	179
Trimble County 8	159	179
Trimble County 9	159	179
Trimble County 10	159	179
Business Solar	0.2	0
Solar Share	1.3	0

[5] Projected net ratings as of 2022. OVEC's ratings reflect the capacity that is expected to be available to the Companies at the time of the respective summer and winter peaks. The ratings for Brown Solar, Business Solar, Solar Share, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer and winter peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

Table 7 lists the generating units that are assumed to retire during the 15-year IRP planning period (2022-2036). The 2020 ECR analysis demonstrated that installing the water treatment capacity needed to simultaneously operate all four coal units at the Mill Creek station and comply with the amended Effluent Limit Guidelines ("ELG") is not least-cost. In addition, there is some likelihood that a new cooling tower will eventually be needed for Mill Creek Unit 1 to comply with Clean Water Act 316(b) regulations. For these reasons, the 2021 IRP assumes Mill Creek 1 will be retired in 2024, the Mill Creek station's deadline for ELG compliance.

Due to their age and inefficiency, the Companies' small-frame SCCTs do not undergo major maintenance, and the Companies plan to retire these units once a maintenance event renders them uneconomic to repair. Since the 2018 IRP, the Companies have retired Cane Run 11 and Paddy's Run 11 in this manner, and expect to retire Zorn before the end of 2021. For purposes of long-term planning in this analysis, the Companies assume that the remaining small-frame SCCTs, Haefling 1-2 and Paddy's Run 12, will be retired by 2025.

Significant changes in environmental regulations since the 2018 IRP are discussed in Section 6 if Volume I of the 2021 IRP. Based on these changes and the analysis summarized in Exhibit LEB-2 is Case Nos. 2020-00349 and 2020-00350, the 2021 IRP assumes Mill Creek 2 and Brown 3 will be retired in 2028. Based on the current debate regarding new laws and regulations to reduce CO_2 emissions that is mainly focused on stimulating the addition of "clean energy resources" or setting "clean energy standards", the Companies have assumed that all remaining CO_2-emitting units are retired at the end of their book lives for purposes of this analysis.

Table 7: Assumed Unit Retirement Dates

Unit(s)	Assumed Retirement Year
Mill Creek 1	2024
Haefling 1-2, Paddy's Run 12	2025
Mill Creek 2, Brown 3	2028
Ghent 1-2, Brown 9	2034
Brown 8 and 10	2035
Brown 11	2036

3.3 New Generation Specifications

Table 8 and Table 9 list the dispatchable and non-dispatchable resource options that were selected for evaluation in this analysis. These resources set the foundation for a clean energy transition. Non-dispatchable resources include wind and utility-scale solar resources located in Kentucky. Dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines with carbon capture and sequestration ("NGCC w/ CCS"), and 4-hour and 8-hour battery storage. Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions. SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

Table 8: Dispatchable Resources (2022 Installation; 2022 Dollars)

	SCCT	NGCC w/CCS	Battery Storage 4-hour	Battery Storage 8-hour
Summer Capacity (MW)[6]	220	513	1+	1+
Winter Capacity (MW)[6]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[7]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[7]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[7]	22	69	32	58
Firm Gas Cost ($/kW-yr)[8]	22	22	N/A	N/A
Variable O&M ($/MWh)[7]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

Table 9: Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

	KY Solar	KY Wind
Summer Capacity (MW)[9]	100+	100+
Winter Capacity (MW)[9]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[7]	25.1%	27.4%
Capital Cost ($/kW)[7]	1,305	1,325
Fixed O&M ($/kW-yr)[7]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[10]	N/A	15

With the exception of summer and winter capacity values, firm gas cost assumptions, and renewable contributions to summer and winter peak, the cost and operating inputs for the generation resources in Table 8 and Table 9 are based on the "Moderate" case forecast from the National Renewable Energy Laboratory's ("NREL's") 2021 Annual Technology Baseline ("ATB"). NREL's SCCT capital cost reflects the cost of constructing a single SCCT at a greenfield site. Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower. NREL's fixed O&M assumptions for each resource escalate over time in

[6] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled battery storage resources in 100 MW increments.

[7] Source: NREL's 2021 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2019 dollars, to nominal dollars at 2% annually.

[8] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

[9] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled solar and wind resources in 100 MW increments.

[10] Production Tax Credit of $15/MWh included for the first 10 years of wind resources.

nominal dollars with the exception of KY Solar and battery storage, which decrease until year 2030 and then escalate.

This analysis assumes summer reserve margin contributions of 78.6 percent for solar and 24.2 percent for wind, and winter reserve margin contributions of 0.0 percent for solar and 31.9 percent for wind. For purposes of this analysis, the Companies are assuming the Investment Tax Credit ("ITC") will be expanded to apply to battery storage installations regardless of whether or not they are co-located and associated with solar generation.

3.4 Fuel and Emission Prices

3.4.1 Natural Gas Prices

Table 10 contains the range of natural gas prices considered in this analysis. Advancements in natural gas drilling technologies have created an abundance of natural gas supply and greatly improved the economics of NGCC technology. More recently, natural gas prices have been buoyed by growing demand from Mexican pipeline and Liquified Natural Gas (LNG) exports. Additional factors that could provide upward pressure on prices include regulations targeting methane emissions from extraction wells, outright bans on the extraction technique of fracking, and significant growth in gas-fired baseload energy production to support intermittent renewable generation. The level of natural gas prices determines the favorability of renewable technology options; as natural gas prices increase, the value of renewable technology options potentially increases.

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas prices. For the base gas case, the Henry Hub price forecast in 2022 through 2024 reflects monthly forward market prices from NYMEX as of July 14, 2021. In subsequent years, the base forecast is interpolated to reach the Energy Information Administration's ("EIA") High Oil and Gas Supply case from its 2021 Annual Energy Outlook ("AEO") in 2050. The low Henry Hub price forecast reflects the actual spot price in 2020 escalated by half of the compound annual growth rate of the smoothed AEO High Oil and Gas Supply case. The high Henry Hub gas price forecast reflects a smoothed version of the EIA's reference case forecast from its 2021 AEO.

Table 10: Henry Hub Natural Gas Prices (Nominal $/MMBtu)

Year	Low	Base	High
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.2 Coal Prices

Table 11 lists the coal price forecast for the Illinois Basin. In the first five years of the forecast, the market price is a blend of prices based on coal bids received, but not under contract, and forecasts from independent third party consultants. Beyond the fifth year, prices are increased at the annual growth rate reflected in the EIA's 2021 AEO High Oil and Gas Supply case for "All Coals, Minemouth" price forecast. The high and low coal price forecasts reflect the historical relationship of changes in natural gas and ILB coal prices.

Table 11: Illinois Basin Coal Prices (Nominal \$/MMBtu)

Year	Low	Base	High
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.3 SO_2 and NO_x Emissions Allowance Prices

The emissions allowance price forecasts for SO_2 and NO_x are based on a third-party consultant’s forecast as of May 2021.

Table 12: SO_2 and NO_x Emission Prices (Nominal \$/short ton)

Year	Annual NO_x	Ozone NO_x	SO_2
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]

3.4.4 CO_2 Prices

Currently, there is no price associated with CO_2 emissions and no law or regulation is being seriously discussed that would explicitly put a price on such emissions. Instead, much focus recently has been on addressing CO_2 emissions indirectly via a Clean Energy Standard rather than through a CO_2 price or cap and trade scheme. During the Obama administration, the Clean Power Plan sought to reduce CO_2 emissions via state administered programs that focused on either emission rates or mass reductions rather than through a CO_2 price. The Companies have no basis for assuming that a price on CO_2 emissions will or will not be part of part of any such regulations. For these reasons, the 2021 IRP does not evaluate resource expansion plans with an assumed price for CO_2 emissions.

3.5 Other Inputs

3.5.1 Reserve Margin

The Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.[11] The derivation of these reserve margin targets are discussed in detail in 2021 IRP Reserve Margin Study.

3.5.2 Financial Inputs

Table 13 provides the financial inputs used to calculate revenue requirements and the revenue requirements discount rate.

Table 13: Key Financial Inputs

Input	Value
Return on Equity	9.425 %
Cost of Debt	3.96 %
Capital Structure	
Debt	46.78 %
Equity	53.22 %
Tax Rate	24.95 %
Revenue Requirement Discount Rate	6.41 %

[11] Because winter peak demands are more volatile than summer peak demands, the Companies require more reserves (relative to the forecasted summer and winter peak demand under normal weather conditions) in the winter months than in the summer months.

4 Resource Planning Analysis

4.1 Capacity and Energy Need

Table 14 and Table 15 contain the Companies' peak demand and resource summaries in the base load forecast scenario and reflect the assumed unit retirements in Table 7, as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[12]

[12] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Table 14: Summer Peak Demand and Resource Summary (MW, Base Load Forecast)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gross Peak Load	6,522	6,500	6,485	6,461	6,424	6,399	6,378	6,366	6,368	6,344	6,346	6,340	6,331	6,334	6,337
Non-Dispatchable DSM	-294	-300	-305	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311
Net Peak Load	6,229	6,201	6,179	6,150	6,113	6,088	6,067	6,055	6,056	6,033	6,035	6,029	6,020	6,023	6,026
Generation Resources	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Demand Conservation Program ("DCP")	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43
Retirements/Additions															
Coal[13]	-300	-300	-300	-300	-300	-300	-1,009	-1,009	-1,009	-1,009	-1,009	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs[14]	0	0	0	0	0	0	0	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs[15]	0	0	0	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47
Solar PPAs[16]	0	79	79	204	204	204	204	204	204	204	204	204	204	204	204
Total Supply	7,576	7,653	7,651	7,728	7,727	7,725	7,015	7,013	7,012	7,011	7,010	7,009	5,927	5,684	5,562
Reserve Margin	1,348	1,452	1,472	1,578	1,614	1,637	947	958	956	978	975	980	-93	-339	-465
Reserve Margin %	21.6%	23.4%	23.8%	25.7%	26.4%	26.9%	15.6%	15.8%	15.8%	16.2%	16.2%	16.3%	-1.6%	-5.6%	-7.7%

[13] The Companies assume that Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. This analysis assumes that Mill Creek 1 is retired in 2024, Mill Creek 2 and Brown 3 are retired in 2028, and Ghent 1-2 are retired in 2034.

[14] This analysis assumes that Brown 9 is retired in 2034, Brown 8 and 10 are retired in 2035, and Brown 11 is retired in 2036.

[15] This analysis assumes that Haefling 1-2 and Paddy's Run 12 are retired by 2025.

[16] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect 78.6% expected contribution to summer peak capacity as specified in section 3.3.

Table 15: Winter Peak Demand and Resource Summary (MW, Base Load Forecast)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Net Peak Load	5,898	5,874	5,859	5,831	5,806	5,790	5,777	5,758	5,750	5,736	5,738	5,726	5,715	5,719	5,737
Generation Resources	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirements/Additions															
Coal	0	0	0	-300	-300	-300	-1,013	-1,013	-1,013	-1,013	-1,013	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs	0	0	0	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
Solar PPAs[17]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Supply	8,100	8,100	8,100	7,744	7,744	7,744	7,031	7,031	7,031	7,031	7,031	7,031	5,928	5,662	5,534
Reserve Margin	2,201	2,226	2,240	1,913	1,939	1,954	1,254	1,274	1,282	1,295	1,293	1,305	213	-57	-203
Reserve Margin %	37.3%	37.9%	38.2%	32.8%	33.4%	33.8%	21.7%	22.1%	22.3%	22.6%	22.5%	22.8%	3.7%	-1.0%	-3.5%

Table 16 provides a summary of summer and winter reserve margins across base, high, and low load forecasts. The Companies' analysis assumes maintaining reserve margins in the range of 17 to 24 percent in the summer and 26 to 35 percent in the winter as stated in section 3.5.1. In the base load scenario, the Companies are forecasting a capacity need in 2028 following the assumed retirements of Mill Creek 2 and Brown 3, and further capacity needs in 2034 with the retirements of Ghent 1-2 and Brown 9. In the high load forecast, a winter capacity shortfall exists beginning in 2026 due to a higher penetration of electric space heating, which shortfall renewable resources such as solar would not be well suited to serve. As discussed in Section 5.(3) of Volume I, increases in electric heating penetration were assumed to begin in 2024 to evaluate the effects of a significant increase in electric space heating by the end of the IRP analysis period. Absent a new law or mandate, this transition is unlikely to begin in 2024. In the low load forecast, the Companies do not have a capacity need until the retirements of Ghent 1 and 2 in 2034.

[17] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect zero expected contribution to winter peak capacity as specified in section 3.3.

Table 16: Reserve Margin Forecasts Across Load Scenarios

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base Load															
Net Peak Load Summer	6,229	6,201	6,179	6,150	6,113	6,088	6,067	6,055	6,056	6,033	6,035	6,029	6,020	6,023	6,026
Net Peak Load Winter	5,898	5,874	5,859	5,831	5,806	5,790	5,777	5,758	5,750	5,736	5,738	5,726	5,715	5,719	5,737
Reserve Margin Summer %	21.6%	23.4%	23.8%	25.7%	26.4%	26.9%	15.6%	15.8%	15.8%	16.2%	16.2%	16.3%	-1.6%	-5.6%	-7.7%
Reserve Margin Winter %	37.3%	37.9%	38.2%	32.8%	33.4%	33.8%	21.7%	22.1%	22.3%	22.6%	22.5%	22.8%	3.7%	-1.0%	-3.5%
High Load															
Net Peak Load Summer	6,230	6,204	6,265	6,248	6,294	6,283	6,270	6,271	6,280	6,291	6,312	6,315	6,330	6,350	6,379
Net Peak Load Winter	5,899	5,875	6,030	6,120	6,287	6,395	6,494	6,590	6,769	6,854	6,961	7,076	7,211	7,334	7,648
Reserve Margin Summer %	21.6%	23.3%	22.1%	23.7%	22.8%	23.0%	11.9%	11.8%	11.7%	11.4%	11.1%	11.0%	-6.4%	-10.5%	-12.8%
Reserve Margin Winter %	37.3%	37.9%	34.3%	26.5%	23.2%	21.1%	8.3%	6.7%	3.9%	2.6%	1.0%	-0.6%	-17.8%	-22.8%	-27.6%
Low Load															
Net Peak Load Summer	6,175	6,134	6,024	5,975	5,849	5,800	5,731	5,602	5,564	5,445	5,448	5,362	5,364	5,361	5,321
Net Peak Load Winter	5,839	5,804	5,693	5,656	5,535	5,502	5,472	5,444	5,430	5,395	5,395	5,367	5,325	5,337	5,364
Reserve Margin Summer %	22.7%	24.8%	27.0%	29.3%	32.1%	33.2%	22.4%	25.2%	26.0%	28.8%	28.7%	30.7%	10.5%	6.0%	4.5%
Reserve Margin Winter %	38.7%	39.6%	42.3%	36.9%	39.9%	40.8%	28.5%	29.2%	29.5%	30.3%	30.3%	31.0%	11.3%	6.1%	3.2%

4.2 Development of Expansion Plan Alternatives

The Companies developed least-cost resource plans over three load and three fuel price scenarios with the resources in Table 8 and Table 9. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions.

4.3 Analysis Results

Table 17 shows the least-cost resource plans in the base load scenario. The base load forecast is relatively flat, so new resources are needed only to replace retired capacity. With base fuel prices, the least-cost expansion plan through 2036 includes 6 SCCTs, 2,100 MW of solar, and 200 MW of batteries. With high fuel prices, there is more emphasis on solar and battery storage in lieu of SCCT capacity. With low fuel prices, the least-cost expansion plan contains significantly less solar. Across all fuel price scenarios, the Companies' expect a greater reliance on the remaining existing generating resources, with a greater proportion of production coming from nighttime hours in proportion to the amount of solar generation that is deployed.

Table 17: New Generation in Least-Cost Resource Plans, Base Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026			
2027			
2028	2 SCCTs, 500 MW Solar	2 SCCTs, 1,000 MW Solar	2 SCCTs, 300 MW Solar
2029			
2030			
2031			
2032			
2033			
2034	4 SCCTs, 1,600 MW Solar	2,400 MW Solar, 800 MW Batteries	4 SCCTs
2035	100 MW Batteries	300 MW Batteries	1 SCCT
2036	100 MW Batteries	300 MW Wind	
Total New Generation	6 SCCTs, 2,100 MW Solar, 200 MW Batteries	2 SCCTs, 3,400 MW Solar, 300 MW Wind, 1,100 MW Batteries	7 SCCTs, 300 MW Solar

Table 18 shows the least-cost resource expansion plans in the high load scenario. The high load forecast has significant increases in peak load and energy as described in Section 5.(3) in Volume I, so new resources are needed not only to replace retired capacity but also to support load growth. With base fuel prices, the least-cost expansion plan through 2036 includes 6 SCCTs, 3,900 MW of solar, 100 MW of wind, and 2,600 MW of battery storage. With high fuel prices, there is more emphasis on wind in lieu of SCCT capacity and battery storage. With low fuel prices, the least-cost expansion plan includes only SCCTs and solar.

Table 18: New Generation in Least-Cost Resource Plans, High Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026[18]	1 SCCT	1 SCCT	1 SCCT
2027	1 SCCT	1 SCCT	1 SCCT
2028	3 SCCTs, 1,500 MW Solar	3 SCCTs, 1,500 MW Solar	3 SCCTs, 500 MW Solar
2029	1 SCCT	100 MW Batteries	1 SCCT
2030	100 MW Batteries	200 MW Batteries	1 SCCT
2031	100 MW Batteries	100 MW Batteries	
2032	100 MW Batteries	200 MW Batteries	1 SCCT
2033	200 MW Batteries	100 MW Batteries	
2034	2,400 MW Solar, 1,200 MW Batteries	2,200 MW Solar, 1,300 MW Batteries	5 SCCTs, 600 MW Solar
2035	500 MW Batteries	200 MW Wind, 300 MW Batteries	2 SCCT
2036	100 MW Wind, 400 MW Batteries	1,700 MW Wind	2 SCCTs
Total New Generation	6 SCCTs, 3,900 MW Solar, 100 MW Wind, 2,600 MW Batteries	5 SCCTs, 3,700 MW Solar, 1,900 MW Wind, 2,300 MW Batteries	17 SCCTs, 1,100 MW Solar

Table 19 shows the least-cost resource expansion plans in the low load scenario. The low load forecast has decreases in peak load and energy as described in Section 5.(3) in Volume I, so fewer resources are needed to replace retired capacity. With base fuel prices, the least-cost expansion plan through 2036 includes 4 SCCTs, 1,200 MW of solar, 100 MW of wind, and 200 MW of battery storage. With high fuel prices, there is more emphasis on solar and battery storage in lieu of SCCT capacity. With low fuel prices, the least-cost expansion plan relies solely on new SCCT capacity. Across all fuel price scenarios, reductions in load and energy mitigate some of the need for replacement generation. In the base and high fuel price scenarios, the Companies expect a greater reliance on the remaining existing generating resources during nighttime hours and when solar generation is otherwise unavailable.

[18] Note that the 2026 and 2027 SCCTs are being added in this scenario to address winter reliability concerns associated with a higher penetration of electric space heating, which concerns renewable resources like solar are not well suited to address.

Table 19: New Generation in Least-Cost Resource Plans, Low Load Scenario

Year	Base Fuel Prices	High Fuel Prices	Low Fuel Prices
2026			
2027			
2028	500 MW Solar	1,000 MW Solar	
2029			
2030			
2031			
2032			
2033			
2034	4 SCCTs, 700 MW Solar	2 SCCTs, 1,600 MW Solar, 300 MW Batteries	4 SCCTs
2035	100 MW Batteries	300 MW Batteries	1 SCCT
2036	100 MW Wind, 100 MW Batteries	100 MW Wind, 100 MW Batteries	
Total New Generation	4 SCCTs, 1,200 MW Solar, 100 MW Wind, 200 MW Batteries	2 SCCTs, 2,600 MW Solar, 100 MW Wind, 700 MW Batteries	5 SCCTs

Table 20 shows the forecasted CO_2 emissions in 2035 across all three load and fuel price scenarios compared to the Companies' actual emissions from 2010. Emission reductions are greater in scenarios with greater additions of renewable resources, and emissions are expected to drop between 22 to 36 percent in the low fuel price scenario, 36 to 42 percent in the base fuel price scenario, and 42 to 47 percent in the high fuel price scenario.

Table 20: Forecasted CO_2 Emissions vs. 2010 Actuals

Scenario	Year	CO_2 Emissions (short tons)	% Change from 2010
2010 Actual	2010	35,843	--
Base Load, Base Fuel Prices	2035	21,505	-40%
Base Load, High Fuel Prices	2035	19,692	-45%
Base Load, Low Fuel Prices	2035	25,100	-30%
High Load, Base Fuel Prices	2035	22,831	-36%
High Load, High Fuel Prices	2035	20,636	-42%
High Load, Low Fuel Prices	2035	28,079	-22%
Low Load, Base Fuel Prices	2035	20,619	-42%
Low Load, High Fuel Prices	2035	19,155	-47%
Low Load, Low Fuel Prices	2035	22,992	-36%

4.4 DSM Potential

The Companies considered the potential for DSM in context of the base load and base fuel case. Table 17 shows the expansion plan for this case, and Table 21 shows the capacity factors of the Companies' new and existing generating units for this case. The 200 MW of battery storage added in 2035 and 2036 is forecast to operate at a capacity factor of less than 1 percent, and is primarily for serving peak load. Successful deployment of DSM programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

Table 21: Capacity Factors in Base Load, Base Fuel Case

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	23%	29%	27%	30%	26%	25%	26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	2%	2%	2%	2%	2%	3%	3%	7%	6%	5%	2%	2%	3%	2%	3%	5%
Brown 6-7	5%	4%	6%	6%	7%	8%	5%	6%	4%	4%	5%	4%	2%	8%	6%	6%
Brown Solar	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
Cane Run 7	84%	82%	80%	77%	88%	87%	89%	76%	89%	88%	87%	81%	85%	83%	72%	81%
Dix Dam 1-3	29%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Ghent 1	61%	62%	72%	64%	59%	65%	64%	66%	58%	64%	66%	64%	66%	N/A	N/A	N/A
Ghent 2	61%	62%	67%	55%	63%	60%	55%	63%	62%	58%	61%	63%	62%	N/A	N/A	N/A
Ghent 3	65%	61%	62%	58%	57%	53%	56%	61%	60%	56%	58%	59%	60%	59%	59%	58%
Ghent 4	55%	53%	58%	46%	47%	45%	48%	47%	49%	51%	49%	50%	51%	53%	54%	54%
Haefling 1-2	0.1%	0.3%	0.1%	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 1	59%	69%	68%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	35%	30%	31%	36%	79%	76%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	61%	63%	55%	73%	68%	74%	63%	76%	69%	77%	71%	76%	71%	71%	64%	72%
Mill Creek 4	71%	61%	69%	73%	81%	80%	72%	74%	82%	69%	81%	76%	81%	70%	77%	71%
Ohio Falls 1-8	30%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	31%	32%	31%
Paddy's Run 12	0.3%	0.3%	0.1%	0.2%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 13	6%	7%	3%	3%	3%	1%	1%	4%	3%	3%	3%	3%	4%	4%	4%	4%
Trimble County 1	65%	74%	74%	77%	68%	76%	75%	79%	75%	78%	72%	78%	67%	78%	74%	78%
Trimble County 2	76%	69%	61%	65%	64%	59%	67%	69%	68%	67%	66%	67%	66%	60%	66%	65%
Trimble Co 5-10	12%	17%	13%	12%	12%	10%	11%	12%	8%	11%	9%	11%	12%	14%	17%	14%
Zorn 1	0.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Simpsonville Solar	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
New SCCTs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20%	22%	21%	20%	18%	19%	21%	23%	21%
New Solar	N/A	N/A	26%	25%	26%	26%	26%	27%	27%	27%	27%	27%	27%	27%	27%	27%
New Battery Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.4%	0.6%

4.5 Summary of Findings

Table 22 shows the least-cost resource expansion plans across all scenarios. Despite a wide range of load and fuel scenarios, some consistent results emerged. Solar and SCCTs are the predominate resource technology choices until the retirement of Ghent 1 and Ghent 2 in 2034. Battery storage is favored in cases with high renewable penetration. The replacement of Ghent 1 and Ghent 2 is expected to rely on renewable resources for energy in most scenarios, and either SCCTs or battery storage for capacity. And NGCC with CCS is not cost-competitive with solar combined with SCCTs or battery storage in any of the scenarios modeled in this analysis. In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors. Successful deployment of Demand-Side Management ("DSM") programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes.

Table 22: New Generation in Least-Cost Resource Plans

Years	Load Scenario	Fuel Price Scenario	Gas	Solar	Wind	Batteries
2026-2030	Base	Base	2 SCCTs[19]	500 MW	0 MW	0 MW
		High	2 SCCTs	1,000 MW	0 MW	0 MW
		Low	2 SCCTs	300 MW	0 MW	0 MW
	High	Base	6 SCCTs	1,500 MW	0 MW	100 MW
		High	5 SCCTs	1,500 MW	0 MW	300 MW
		Low	7 SCCTs	500 MW	0 MW	0 MW
	Low	Base	0 SCCTs	500 MW	0 MW	0 MW
		High	0 SCCTs	1,000 MW	0 MW	0 MW
		Low	0 SCCTs	0 MW	0 MW	0 MW
2031-2036	Base	Base	4 SCCTs	1,600 MW	0 MW	200 MW
		High	0 SCCTs	2,400 MW	300 MW	1,100 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW
	High	Base	0 SCCTs	2,400 MW	100 MW	2,500 MW
		High	0 SCCTs	2,200 MW	1,900 MW	2,000 MW
		Low	10 SCCTs	600 MW	0 MW	0 MW
	Low	Base	4 SCCTs	700 MW	100 MW	200 MW
		High	2 SCCTs	1,600 MW	100 MW	700 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource planning analysis represents the Companies' analysis of the best options to meet customer needs at this point in time, this

[19] A SCCT is assumed to have a summer capacity of 220 MW and a winter capacity of 248 MW. In the high load scenario, SCCT capacity is first added in 2026 to address winter reliability concerns associated with a higher penetration of electric space heating. In the base load scenario, SCCT capacity is first added in 2028 to address the reserve margin need resulting from the retirements of Mill Creek 2 and Brown 3.

plan is reviewed, re-evaluated, and assessed against other market-available alternatives prior to commitment and implementation.

The Companies identify transmission construction projects and upgrades required to maintain the adequacy of their transmission system to meet projected customer demands and address any changes to the generation resource mix. This is accomplished through various existing processes, including the annual Transmission Expansion Plan, Generator Interconnection Requests, and Transmission Service Requests.

Transmission Expansion Plan (TEP) Process

The TEP is developed annually and utilizes customer load forecasts and the expected generation to serve that load over a ten-year period. The TEP complies with NERC Reliability Standard TPL-001, the Companies Transmission Planning Guidelines, and is approved by the Independent Transmission Organization (ITO).

The TEP study process includes analyzing the base case for summer, winter, and off-peak seasons, plus over 100,000 contingencies (i.e., generator and transmission equipment outages and combinations including neighboring systems). This analysis identifies potential transmission constraints and results in construction projects or upgrades to maintain system reliability.

The annual TEP process ensures the transmission system can accommodate any expected future changes in the generation resource mix can meet future customer demand.

Generator Interconnection (GI) Process

New generation resources pursuing interconnection with the Companies' transmission system are required to follow the FERC approved Open Access Transmission Tariff GI process. This process is designed to maintain the reliability of the grid while allowing generation resources to connect in a fair and consistent manner.

The generation interconnection process requires generator owners to submit their generation projects to a queue by providing information that includes the exact location, capacity, and commercial operations start date. Transmission studies are performed in queue order. The studies identify any applicable transmission projects required to prevent reliability issues because of power flow changes on the grid with the generator addition.

The ITO oversees this process and approves new GI requests.

Transmission Service Request (TSR) Process

New delivery points for load or qualifying load increases at existing delivery points (5 MW or more on 69 kV facilities or 10 MW or more at higher voltage facilities) require the load serving entity to submit a TSR. Similar to the GI process, transmission studies are performed in queue order. Any transmission projects needed to accommodate the incremental load are identified.

The ITO oversees this process and approves new GI requests.

Transmission Considerations from Retiring Conventional Spinning Generation & Incorporating Inverter-Based Resources

As the Companies and the utility industry consider the retirement of conventional spinning generation and adding Inverter-Based Resources (IBR), the Companies' Transmission Department is preparing to support such a transition. As final generation resource decisions are made, the processes outlined above will be utilized to maintain system reliability.

Primary considerations that impact whether new or upgraded transmission facilities are needed include:

- Amount of IBR installed capacity
- Location and geographic dispersion of IBR
- Ability of the resulting generation portfolio to provide grid stability

There are two primary reliability functions typically supplied to the grid by conventional spinning generation that provide grid stability: frequency and voltage control. As IBRs are added to the grid in place of conventional spinning generation, transmission studies will be performed to ensure adequacy of voltage and frequency support.

The adequacy of frequency and voltage support is highly dependent on the location of those resources compared to load. For example, if a large generator has strong voltage and frequency support but is connected to the grid far from load centers, the resource will be unable to support voltage and frequency at a level comparable to a resource located close to the load center.

In Kentucky, high renewable penetration is more likely at locations with smaller load centers (i.e., rural areas). Therefore, voltage and frequency support equipment traditionally supplied by conventional spinning generation may be required near load centers. Voltage and frequency support equipment may could include the following:

Voltage Support

- Conversion of retired synchronous machines to condensers
- New synchronous condensers
- Static VAR Compensators (STATCOM)

Frequency Support

- Headroom requirements for new resources
- Synchronous condensers that add inertia to the grid

- Batteries that do not function as a generation resource. These would be partially charged to function as either a load or a generator during frequency events but otherwise are in standby mode.
- Available combustion turbines connected to the grid at minimum levels to provide real power during low frequency events.

The exact quantities and locations of the above listed devices will not be known without detailed information for the generation projects. But through the generation interconnection process, transmission will be able to integrate renewable resources while maintaining grid reliability.

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Kentucky Utilities Company / Louisville Gas and Electric Company

Project Number	Transmission Expansion Plan Projects	Estimated Timetable for Implementation

CONFIDENTIAL

Transmission System Map

2021 RTO Membership Analysis

PPL companies

October 2021

Contents

1 Executive Summary

This analysis was performed to evaluate whether membership in the Midcontinent Independent System Operator ("MISO") or the PJM Interconnection ("PJM") Regional Transmission Organizations ("RTOs") may provide potential net benefits to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively "the Companies") retail and wholesale requirements customers. This study is designed to be a high-level screening analysis to determine if the potential benefits and costs of RTO membership support future RTO membership, particularly in conjunction with the assumed retirement of Mill Creek unit 2 and Brown unit 3 in 2028.

This report discusses the risks, uncertainties, and non-quantifiable considerations regarding RTO membership and presents the results of the Companies' financial analysis. The Companies evaluated the sum of the financial impacts of the items shown in Table 1 through 2027. In 2028, the Companies assume that the retirements of Mill Creek unit 2 and Brown unit 3 will occur resulting in a capacity need. While the timing of these retirements is uncertain, this analysis assumes a 2028 retirement year. Once the Companies become "short" of capacity, the analysis of potential RTO benefits becomes much more challenging and uncertain. Inside an RTO, the Companies' resource planning activities change from focusing on the lowest cost means to reliably serve load to one of managing the market price risk of serving load (note that in an RTO, all load is served at market prices). The items in Table 1 reflect the potential incremental costs and benefits of RTO membership compared to non-RTO membership through 2027 but do not capture potential costs associated with actively managing the market price risk of serving customers' load.

Table 1: RTO Membership Cost and Benefit Components

Costs	Benefits
• RTO Admin Fee • Energy Uplift • Transmission Expansion • Internal Staffing & Implementation • Lost Transmission Revenue • Lost Joint Party Settlement Revenue	• Misc. Avoided Fees • Elimination of Depancaking • RTO Energy Market Impacts • RTO Capacity Market Impacts

The Companies' 2020 RTO Membership Analysis indicated that membership in MISO or PJM was not beneficial at that time. Key assumption changes from the 2020 study are

(1) evaluating a longer study period, which aligns with the analysis period of the Companies' 2021 Integrated Resource Plan (IRP), and

(2) considering the long-term impacts and risk profile regarding the composition of the Companies' generating fleet after the assumed retirements of several of the Companies' existing generating units.

The second assumption is a key change and a major consideration in this updated analysis, as retirements present a range of options for replacements of the retired units with associated potential savings and risks. While there may be an option to avoid future generation investments by joining an RTO, the attendant savings from such an option come with reliability risks and the need to effectively manage what could be significant exposure to market price risks for energy and capacity in the RTOs. Recognizing the range of uncertainties, the Companies have not attempted to develop an assumed price risk management plan for RTO membership but instead reviewed the potential new costs and benefits associated with the new risk profile inherent in RTO membership. Specifically, to demonstrate the range of the market uncertainties, the Companies identified the magnitude of supply side cost savings that will be required in 2028 and beyond to offset the added costs of joining an RTO.

Figure 1 and Figure 2 depict the annual sums of the ranges of values for the component items shown in Table 1 through 2027 for each RTO and demonstrate a range of favorability of RTO membership in the near term.[1] While the cases shown present discrete views for RTO membership favorability, they are intended to represent the distribution of potential outcomes. The green bars represent the high-favorability case, which is the combination of assumptions that results in the most favorable case for RTO membership in each year. The blue bars represent the least favorable combination of assumptions in each year. The red bars represent a case with mid-level assumptions. As the figures show, joining MISO is unfavorable in each year in all cases. The analysis for joining PJM is a bit more mixed with the high case showing the potential for savings and the mid case near zero (ranging between $4 million unfavorable and $2 million favorable). This difference is due primarily to the lower transmission expansion costs and higher forecasted capacity prices assumed in PJM compared to MISO.

[1] Negative values in Figure 1 and Figure 2 indicate that RTO membership is unfavorable.

Figure 1: MISO Range of Potential Near-Term Outcomes ($M)[2]

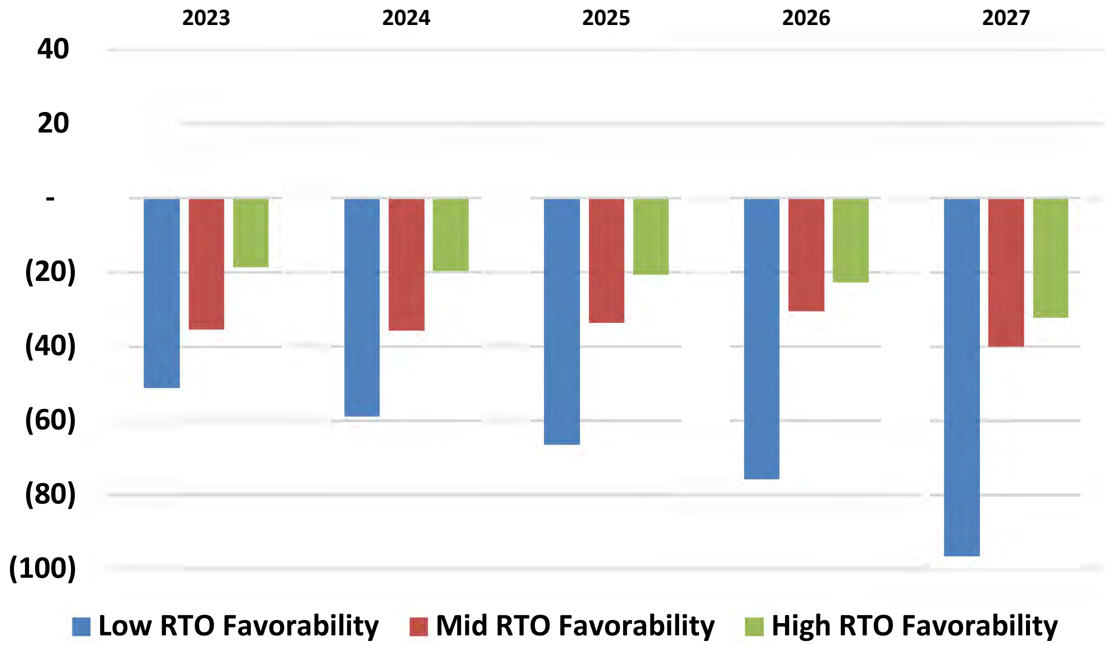
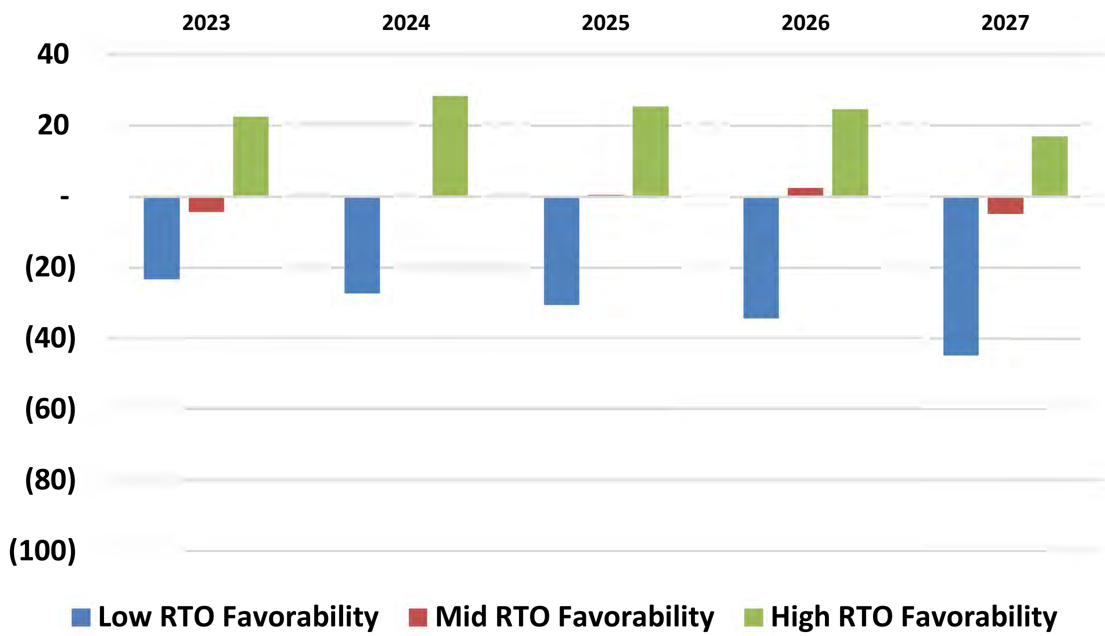


Figure 2: PJM Range of Potential Near-Term Outcomes ($M)[2]



PJM's high-favorability case ranges between $22 million and $28 million more favorable than the mid-case. Achieving this high favorability in the RTO requires the alignment of

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[2] Negative values indicate that RTO membership is unfavorable.

favorable assumptions for several of the cost and benefit components shown in Table 1. Table 2 shows the annual variance between the mid-favorability case and the high-favorability case for each of these variable components.

Table 2: Variances between PJM High and Mid-Favorability Cases ($M)

	2023	2024	2025	2026	2027
Lower Admin Fees	3.6	3.7	3.7	3.8	3.9
Energy Market Benefits	10.4	8.9	5.3	2.3	3.5
Capacity Market Benefits	8.4	11.8	11.8	11.8	11.8
Elimination of Depancaking	4.2	4.0	4.0	4.1	2.4
Total Variance	**26.6**	**28.4**	**24.8**	**22.0**	**22.0**

Figure 3 and Figure 4 provide longer-term views of the range of each RTO's projected fixed costs and shows that by the end of the study period in 2036, up to approximately $100 to $220 million in costs would need to be offset by savings for RTO membership favorability to break even. The difference between PJM and MISO is primarily due to the lower transmission expansion costs assumed in PJM compared to MISO. Such savings can come in the form of energy and capacity revenues and/or avoided generation investments. But such savings can also come with energy and capacity market price risk, the level of which depends highly on the Companies' strategy to mitigate this exposure, whether through financial hedging and/or through constructing or purchasing generating resources to participate in the RTO markets. Note that the market attributes (e.g., capacity price level, energy prices, etc.) that might make RTO membership attractive or unattractive prior to 2027 when the Companies are anticipated to have ample physical generation may have the opposite effect post-2028 when the Companies are assumed to be capacity deficient. For example, the potential to earn higher capacity revenues in PJM through 2027 would add to costs once Mill Creek units 1 and 2 and Brown unit 3 are retired.

Figure 3: Projected Fixed Costs Range - MISO ($M)

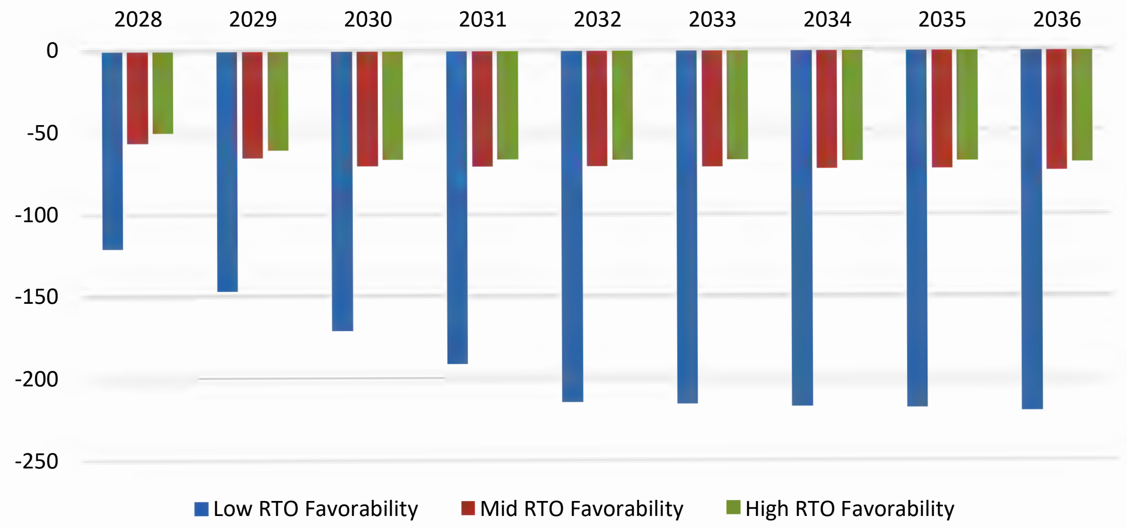
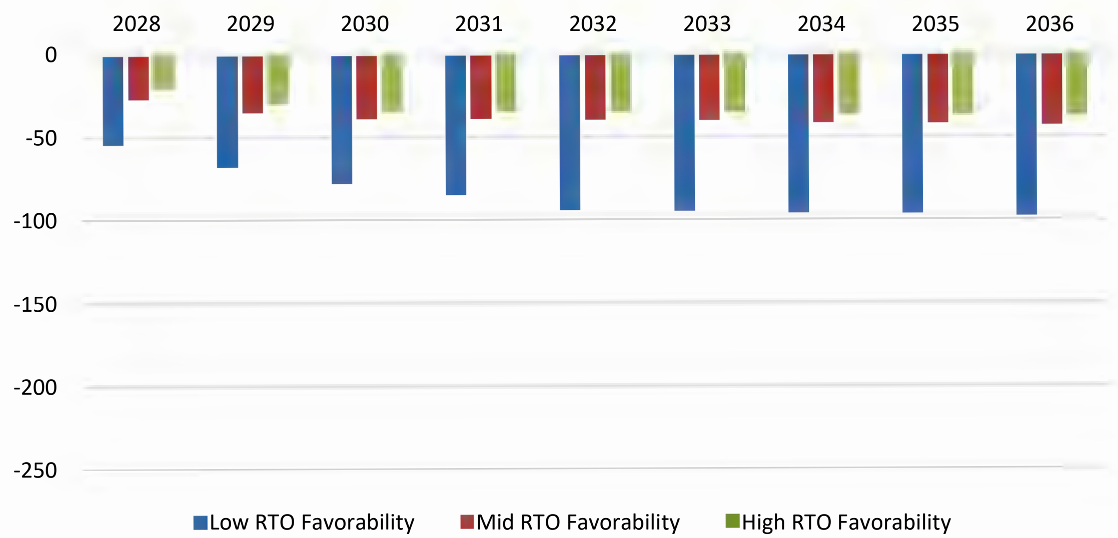


Figure 4: Projected Fixed Costs Range - PJM ($M)



Based on the analysis detailed in this report and the great deal of uncertainty regarding the evolving RTO markets, the Companies do not recommend RTO membership at this time. However, potential RTO membership should be considered in conjunction with the retirement timing for Mill Creek unit 2 and Brown unit 3. This study indicates that there is likely little benefit to joining MISO prior to 2028 while joining PJM could be beneficial before then if actual capacity and energy prices are high. However, when future generation retirements are assumed to occur starting in 2028, the Companies' evaluation of replacement generation would change in an RTO compared to operating on a standalone basis. Being in an RTO involves a change in mindset from having a fleet of physical generation assets to reliably serve load 8760 hours a year as a standalone utility to thinking in terms of financial risk management of both generation and load as independent activities. In an RTO, the Companies would be relying on a separate entity for managing reliability and dispatching the RTO's generation fleet to serve real-time load. At the same time, being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology, as RTO membership may support higher levels of renewable penetration with lower integration costs.

2 Introduction

As described in this report, the Companies have performed an updated review using available information and existing modeling functionality to determine whether RTO membership in MISO or PJM may provide potential net benefits to the Companies' customers. For purposes of this analysis, RTO membership includes transferring functional control of transmission assets and mandatory participation by the Companies' generation and load in the various markets currently administered by the RTO. It results in a much different operating paradigm and risk profile than the status quo. But as the industry transitions to cleaner energy resources, RTO membership may present the best path for integrating high levels of renewable penetration if necessary changes are achieved by the RTOs to address potential shortfalls in capacity and energy adequacy and reliability.[3]

As in the 2018 and 2020 analyses, a cross-functional team evaluated the major costs, benefits, opportunities, and uncertainties of RTO membership as compared to standalone operations of the Companies.[4] The team started with confirming that the components expected to have financial impacts in the 2020 analysis continued to be the correct components to address in the updated quantitative analysis. It was determined that it was appropriate to perform the updated quantitative analysis using mostly the same components, subject to some revisions in the underlying assumptions associated with those components as described below. In addition, the team re-examined and updated non-quantifiable considerations and uncertainties determined to have the potential to materially impact the decision. Critical non-quantifiable considerations are addressed in the next section, and an updated list and summary of non-quantifiable considerations is

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[3] For example, see "MISO's Renewable Integration Impact Assessment," February 2021, at https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

[4] The team consisted of representatives from Corporate Compliance, Energy Planning Analysis & Forecasting, Federal Policy, Legal, Power Supply, Transmission, and State Regulation and Rates.

appended hereto. The subsequent sections describe each of the cost and benefit components considered in the quantitative portion of the analysis, which are then summarized to lead to the Companies' conclusion of not joining an RTO at this time but to continue to evaluate possible future membership and the risks involved.

3 Risk and Uncertainty

3.1 Decision Analysis

The decision to join an RTO is a significant and possibly permanent, long-term commitment that requires careful consideration of many variables and assumptions, including whether operation under the rules of the RTO is consistent with the Companies' obligations to reliably serve customers at the lowest reasonable cost. Fundamentally, it is a decision to transfer functional control of generation and transmission operations to the RTO and participate in current and future RTO-administered wholesale markets for generation and load. RTO policies, requirements, and operations are driven by the changing regulatory landscape, variable market conditions, and diverse stakeholder groups that represent varying interests across multiple states.[5] RTO members, their stakeholders, and state regulators cede control over significant revenue streams, cost incurrence and allocation, and decisions impacting the transmission system and generation fleet – and ultimately cost of service to customers. Furthermore, the decision to join an RTO is complex and extremely difficult to reverse.

This report quantifies projected potential benefits and costs of integration into the RTOs utilizing available data and assumptions to anticipate financial impacts. The range of outcomes of this analysis demonstrate the uncertainty involved, especially in later years. In the near term, however, the data is somewhat clearer and lead the Companies to recommend not joining an RTO at this time. Market prices can be volatile in both the energy and capacity markets, as discussed in the next section. Transmission expansion costs remain an evolving area as transmission planning requirements continue to change and RTO cost allocation provisions are revisited.

Fully integrating into an RTO would commit the Companies to comply with RTO requirements as a supplier, a load-serving entity, and a transmission owner. Therefore, the potential for material changes and unanticipated costs, as well as the uncertainty of

[5] MISO operates over 15 US states and one Canadian province to manage approximately 71,800 miles of high voltage transmission and 192,285 MW of generating resources. PJM operates over 13 states and the District of Columbia to manage over 84,000 miles of high voltage transmission lines and 187,000 MW of generating resources.

any potential benefits, should be considered and fully understood before deciding to join an RTO. Though the Companies focused on quantifiable elements in performing this analysis, certain non-quantifiable considerations form a vital context in which to consider the quantifiable elements.

3.2 Market Price Risk

A key decision for any RTO member is how to manage the risk to customers of paying high market prices for energy and capacity when the member is a net purchaser in these markets. Numerous external factors impact RTO market pricing including fuel costs, weather events, load reductions, incremental resource additions, transmission performance, changes in suppliers, unplanned outages, and federal policy and regulatory changes (e.g., changing environmental regulations or FERC-directed changes in market design, compensation, or requirements). Managing these risks can come in the form of financial hedging forward energy prices, maintaining a level of owned or purchased generation resources to adequately cover capacity and energy needs on a net basis, or a combination of the two.

The RTO capacity markets have demonstrated volatility historically, with prices ranging between $50 and $165/MW-day in PJM and between $1.50 and $72/MW-day for MISO since the 2016/2017 planning year. However, recent prices remain well below the theoretical capacity price ceiling of the cost of new entry ("CONE"), which is currently $264/MW-day in PJM and $244/MW-day in MISO.

The energy markets can be particularly volatile in times of strain on the system when resources are scarcely meeting load. During the extreme cold period in February 2021, MISO's and PJM's real-time prices at LG&E and KU's interface points averaged over $100/MWh for the four days between February 15 and February 18 and reached up to $444/MWh. Prices at MISO's Texas Hub averaged $600/MWh and reached MISO's energy price cap of $3,500/MWh in response to the energy scarcity event in Texas during that period.[6]

On a standalone basis, the Companies manage energy risk in three areas:

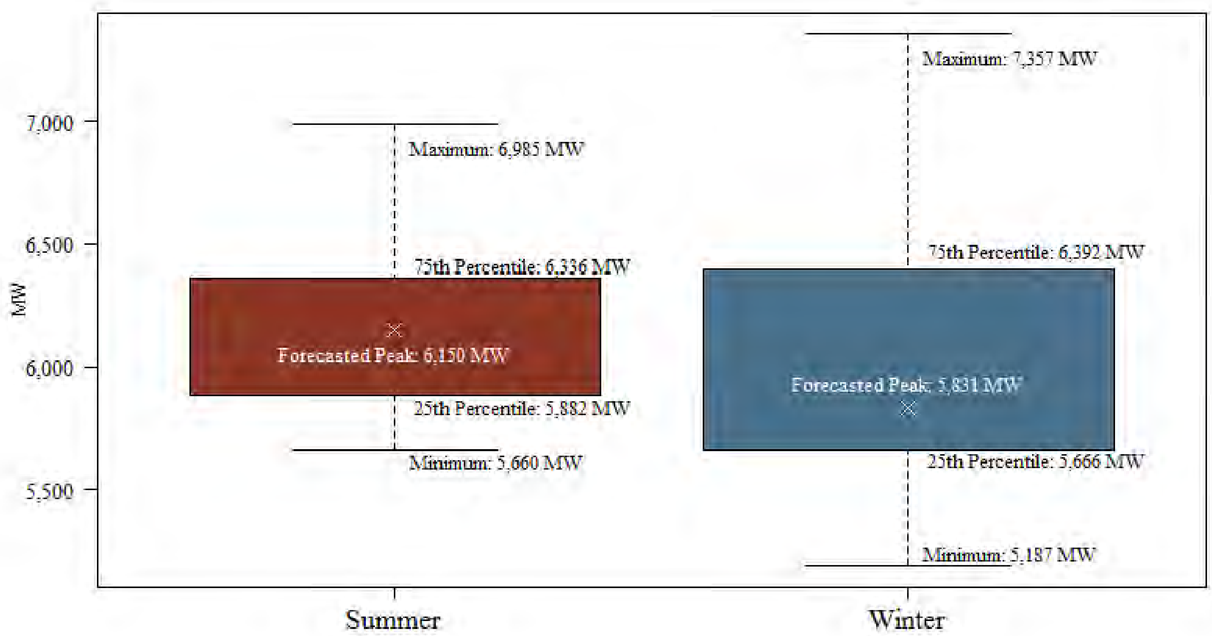
1. Managing fuel risk: maintaining coal inventories, purchasing forward natural gas for generation, and purchasing natural gas transportation rights.
2. Unit reliability: keeping generating units in working order and preparing for extreme operating conditions.

[6] The RTOs' current energy price caps are $3,500/MWh for MISO (LMP total) and $3,750/MWh for PJM (energy portion of LMP, plus congestion and losses).

3. Maintaining reserves: maintaining reserves to accommodate a reasonably wide range of potential seasonal load fluctuations.

In an RTO, fuel risk management and unit reliability would remain the Companies' responsibility while defining required system reserve levels and real-time dispatch would be the RTO's responsibility. The Companies currently manage reserves to meet a range of potential summer and winter peak loads, as shown in Figure 5. In an RTO, the Companies' focus would shift to evaluating the volatility in electricity prices and its correlation with electricity demand (financial risk) rather than just physical electricity demand (reliability risk). Determining the optimal hedging strategy when entering an RTO will require new analytical methods and tools beyond the scope of the Companies' traditional optimization and risk management modeling.[7]

Figure 5: Distributions of Summer and Winter Peak Demands, 2025[8]



[7] For example, given the importance of RTO capacity and energy prices, it would be important to be able to model and forecast RTO regional prices, something the Companies previously did when they were a MISO member. NERC's 2020 Long Term Reliability Assessment shows the differing existing and planned portfolios and reserve expectations between MISO and PJM. *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[8] See Companies' 2021 IRP, Volume III, "2021 IRP Reserve Margin Analysis," October 2021.

3.3 Non-Quantifiable Considerations

3.3.1 Changing Market Rules

The RTOs operate on a defined set of rules and tariffs that dictate all aspects of how participants function in the RTOs' various markets. A key assumption in the Companies' quantitative RTO membership analysis is that these RTO rules and tariffs remain unchanged over the 14-year analysis period because there is no basis on which to make any other assumption. However, what is certain is that the RTOs' market rules are in fact in a constant state of change in response to market participants' demands, changes in the industry, and unpredictable changes in regulations and policy.[9] For example, the capacity markets in both PJM and MISO continue to be modified in an attempt to better drive new capacity investments with the appropriate market signals. The RTOs have seen very low capacity prices, much lower than the actual cost of new entry. This combined with the limited forward visibility of PJM's 3-year-ahead and MISO 1-year-ahead market leads to little incentive for the construction of new capacity, which could lead to capacity deficiencies if not addressed. MISO has been evaluating a longer visibility period as well as a seasonal capacity market, which may result in new capacity rules. PJM continues to modify its capacity market rules and has often been at odds with FERC on proposed market changes, most recently regarding minimum capacity offer prices and state subsidies for certain capacity types.

3.3.2 Clean Energy Transition

As many entities with fossil fuel fired generation resources contemplate a transition to increased renewable resources, RTOs could be an attractive option for supporting this transition. The diverse geography, resources, and loads in an RTO allow for the integration of higher penetration of intermittent resources than what the Companies could likely achieve on a standalone basis and potentially at lower cost. The RTOs are anticipating this transition by considering the future changes required. MISO projects that up to 30% renewable penetration can be achieved with transmission expansion and significant changes to planning, markets, and operations. [10] MISO projects that even higher penetration can be achieved with more transformational changes and coordination.

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[9] *STRETCHED TO THE BREAKING POINT - RTOs and the Clean Energy Transition* (Tony Clark and Vincent Duane, July 2021) "*RTOs, their stakeholders and regulators have become accustomed to a never-ending refinement of market rules chasing the goal of incentive compatibility.*" Link: https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf

[10] "MISO's Renewable Integration Impact Assessment," February 2021. See https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.

However, as more companies lean on the RTOs to integrate increasing levels of renewables and replace dispatchable generation, reliably meeting customers' energy needs at every moment has the potential to become unsustainable. Furthermore, the RTOs themselves have considered ways to reduce CO_2, including carbon pricing, in the absence of national CO_2 regulations. Achieving CO_2 reductions with new renewables, especially wind resources, will likely require significant transmission investments to move the power from areas with high generation resources to load centers. Depending on these and other variables, it could be more cost-effective for the Companies to be on their own transition path rather than that of the RTOs.

3.3.3 Generation Dispatch Decisions

Generation dispatch decisions in an RTO are driven by a region-wide security constrained dispatch rather than the least-cost means to serve the Companies' customers. The Companies are currently able to make short term decisions to reliably meet their customers' energy needs. This is particularly important prior to and during extreme weather events (like the polar vortices of 2014 and 2015 and the cold weather event in February 2021).[11] An example of the short-term decisions currently available to the Companies during these events include starting units early (particularly simple cycle combustion turbines) to mitigate the potential impacts of forecasted cold weather. Yielding functional control of these real-time generation dispatch decisions to an RTO creates risk of inability to reliably serve load and increased costs (through non-performance or increased maintenance costs) as RTO dispatch decisions are driven by market prices and tariff rules.

3.3.4 Market Defaults

Defaults of other market participants remains unpredictable in RTOs. Both RTOs have established credit policies consistent with FERC requirements designed to limit the potential impacts of default, but a degree of default risk remains. Developers, choice marketers, independent generation, distributed energy resource aggregators, and demand resources participate in the markets alongside traditional load-serving utilities. Entity defaults and bankruptcies present a potential risk that the costs of such behavior will fall to other market participants. When entities default in excess of the financial security held by the RTO or enter bankruptcy proceedings that disrupt or prevent

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[11] On September 23, 2021, FERC and NERC issued preliminary findings and recommendations following their inquiry into the February 2021 cold weather event. Of the twenty-eight recommendations, nine are characterized as key recommendations and include changes to NERC Reliability Standards. Link: February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations | Federal Energy Regulatory Commission (ferc.gov)

recovery through collateral, other RTO members are allocated a portion of the default.[12] A market participant in MISO recently filed bankruptcy because of the February 2021 winter event that predominantly affected Texas, leaving MISO with $10.3 million in unpaid market charges. These charges were assessed to all market participants.

Additional non-quantifiable considerations that would need to be considered further before integrating into an RTO are provided in Appendix D.

3.4 Reliability Metrics[13]

In this 2021 RTO Analysis, the Companies reviewed relevant generation and transmission metrics to compare reliability performance within the RTOs versus the Companies' stand-alone performance. Reliably serving customers' energy needs requires properly aligned long term planning and risk assessment of future energy serving scenarios. As the scenario becomes clearer, executable decisions are reached and actionable activities (which may take years) are set in motion. The quality of such planning decisions, then, manifests in reliability performance metrics. Importantly, these long-term planning activities and responsibilities are different as a member of an RTO than they are as a standalone utility. As an example, the February 2021 outage event in ERCOT illustrates how reliability planning and responsibility is more diffuse in an RTO than would be the case for the Companies currently.

3.4.1 Generation Metrics

Equivalent Forced Outage Rate (EFOR) and Equivalent Unplanned Outage Rate (EUOR) are standard industry metrics that provide a view of the reliability performance of a generator or a generation fleet. EFOR reflects times when generation is forced out of service while EUOR also encompasses short term unplanned maintenance outages; both metrics include derated portions of unit capacity. Figure 6 and Figure 7 contain a three-and-a-

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[12] One example is the default of FTR market participant GreenHat Energy, LLC, and subsequent liquidation of the entity's FTR portfolio. Due to concerns that liquidation of the entire GreenHat FTR portfolio in accordance with the PJM tariff, PJM requested a tariff waiver to liquidate the FTR portfolio in a manner that would minimize market distortion. This waiver request was protested by certain marketers and initially denied by FERC before being sent to paper hearing. Ultimately PJM settled the dispute, allowing it to liquidate the GreenHat FTR portfolio in its preferred manner but also with certain "compromise payments" to the protesting marketers totaling $12.5 million. *See* "Submission of Settlement Agreement and Offer of Settlement," *PJM Interconnection, L.L.C.,* Docket Nos. ER18-2068-000 and ER18-2068-001 (submitted October 9, 2019); *letter order accepting,* 169 FERC ¶ 61,260 (2019). However, liability to current PJM market participants is based on the total default amount, which currently stands at $181.7 million. If LG&E and KU had been load-serving entities in PJM during the GreenHat default, they would have ultimately been responsible for approximately 4% of the total default amount, or $7.3 million.

[13] The Commission Staff Report (issued July 2020) from the Companies' 2018 IRP indicates the Company should consider potential benefits such as "improved reliability" in future RTO Analyses.

half-year history of LG&E and KU's EFOR and EUOR compared to the Reliability First Corporation's (RFC) top quartile and average performance for similar sized baseload units. RFC overlaps both MISO and PJM.

Figure 6: Equivalent Forced Outage Rate

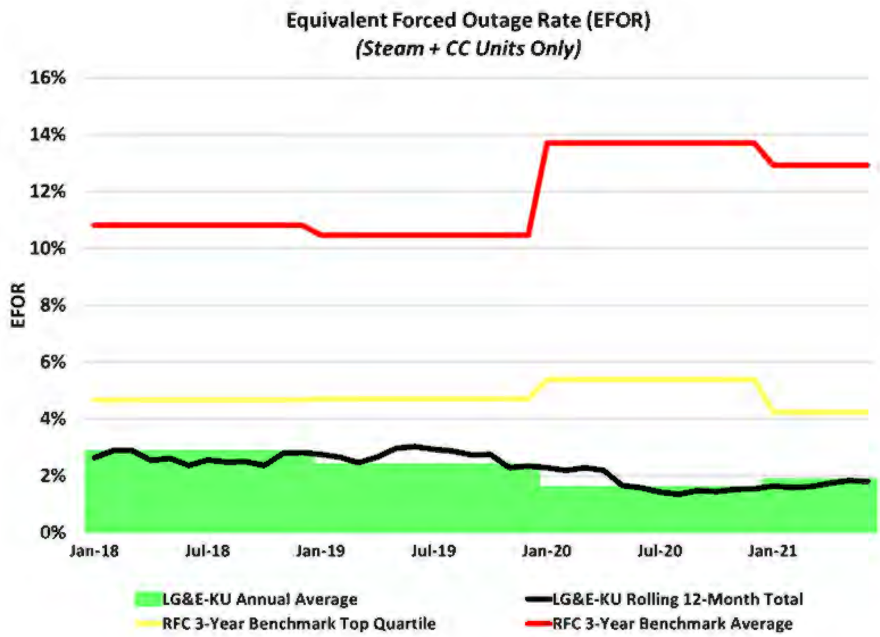
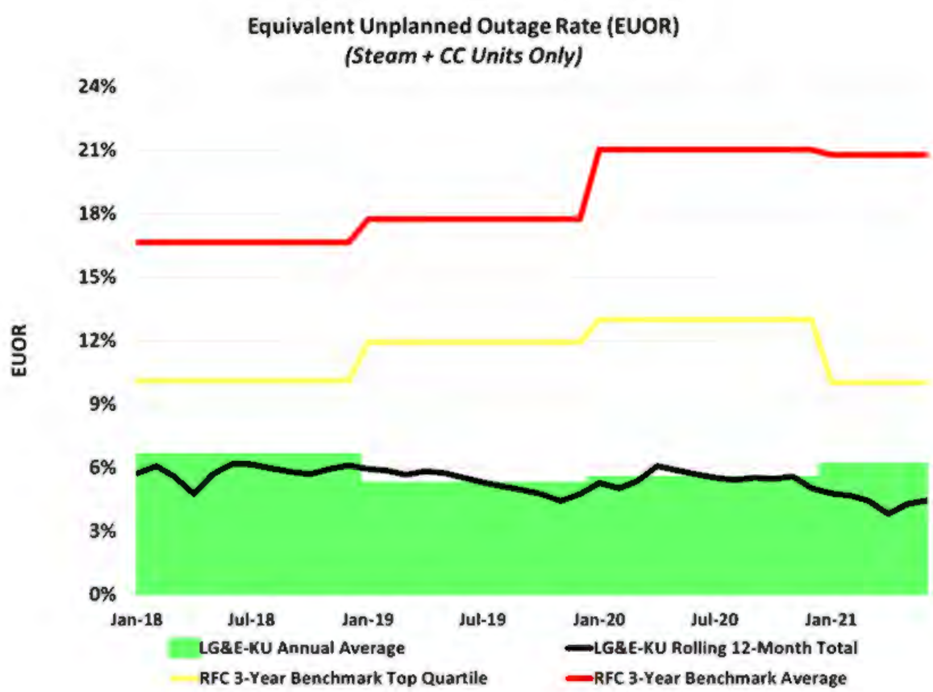


Figure 7: Equivalent Unplanned Outage Rate



Higher than expected EFOR and EUOR increase the likelihood of multiple generation outages occurring concurrently, potentially leading to a capacity shortfall and subsequent energy deficiency.

An Energy Emergency is a condition in which a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected load obligations.[14] An Energy Emergency Alert (EEA) is initiated on that entity's behalf when such conditions are present. As such, EEAs can be an indicator of capacity issues within an RTO. Since exiting MISO in 2006, the Companies have never experienced a resource shortage impacting LG&E/KU load service requiring declaration of an energy emergency alert.

The Companies have identified eight EEA events experienced within MISO since 2017. Of those eight, two reached EEA 3, the most severe level of EEA, resulting in firm load interruption. In August 2020, MISO directed 500 MW of firm load interruption in East Texas due to generation and transmission outages caused by Hurricane Laura. In February 2021, MISO directed 700 MW of firm load interruption across its South region due to its inability to balance generation and load in the face of extreme cold temperatures.

PJM has performed comparatively better during this period, experiencing a single EEA event within its territory in October 2019 caused by unseasonably warm temperatures.

As recently as this summer, NERC's Reliability Assessment indicated several ISOs and RTOs (including MISO[15]) were at elevated risk of experiencing energy supply shortfalls during above normal demand periods, as shown in Figure 8.

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[14] Definition from NERC Glossary of Terms

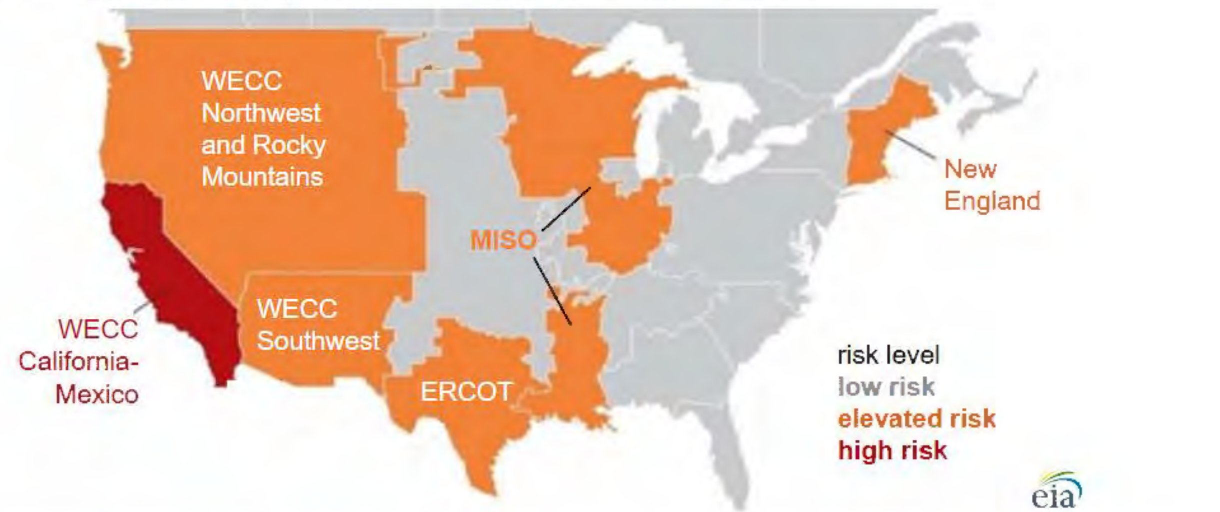
[15] MISO also recognizes their ISO is increasingly facing reliability risks, even outside of the summer peak-load months. *See* https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL_updated%204-29-2021504018.pdf at 3 ("[T]he region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges.").

Figure 8: NERC 2021 Summer Reliability Assessment

JUNE 30, 2021

NERC report outlines potential electricity disruptions in the United States this summer

U.S. energy emergency risk areas, summer (June–September) 2021

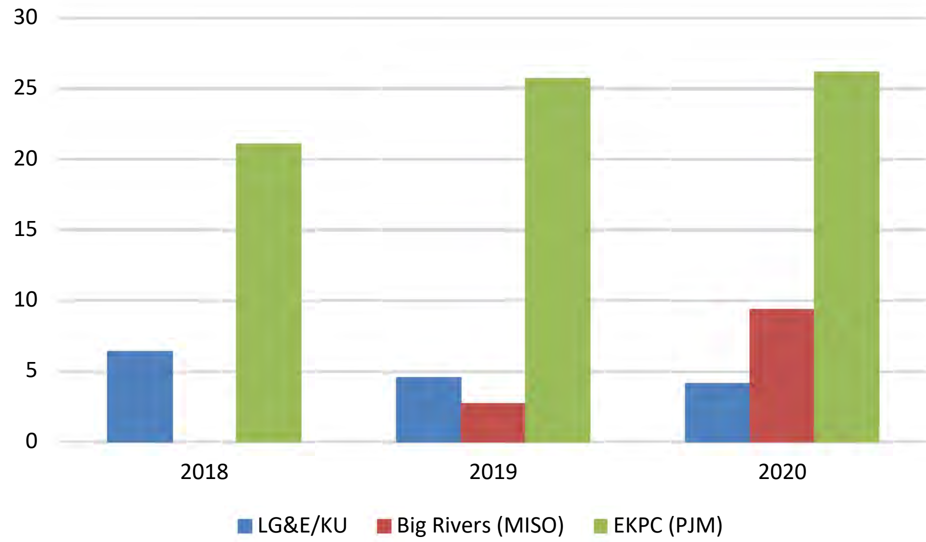


Source: Map by U.S. Energy Information Administration, based on North American Electric Reliability Corporation (NERC) *2021 Summer Reliability Assessment*
Note: ERCOT is the Electric Reliability Council of Texas; MISO is the Midcontinent Independent System Operator; WECC is the Western Electricity Coordinating Council.

3.4.2 Transmission Metrics

Transmission System Average Interruption Duration Index (SAIDI) is a metric to track transmission reliability. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Figure 9 shows a comparison of the SAIDI metric for LG&E/KU, Big Rivers (MISO RTO), and EKPC (PJM RTO) for 2018, 2019, and 2020. This data excludes Major Event Days (MED), each of which includes a severe windstorm or ice storm. Note that SAIDI is not tracked or reported to the RTO; rather, it is used and tracked by each member individually.

Figure 9: SAIDI Comparison Excluding MED[16]



3.4.3 Metrics Summary

The Companies have a long history of reliably serving the energy needs of their customers, even during extreme weather events. These generation and transmission reliability performance metrics quantitatively show successful planning and execution have exceeded neighboring utilities that participate in RTOs. Based on this data, there is no reason to believe that overall customer reliability would improve by joining an RTO.

4 Background

The Companies were founding members of MISO, operating within MISO from 2002 until September 1, 2006, when the Companies terminated their MISO membership with Kentucky Public Service Commission ("Commission") approval.[17] While the Companies are no longer members of MISO, the Companies are market participants in, and regularly transact in, both MISO and PJM.

Since exiting MISO, the Companies have periodically conducted high-level analyses to evaluate whether full membership in an RTO might be beneficial to its customers, and

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[16] Big Rivers SAIDI from 2018 was 15 but it included MED. Therefore, for 2018 the data was not included.

[17] In 2003, the Commission initiated on its own motion an investigation into the Companies' membership in MISO to determine if that membership provided net benefits to customers. *In the Matter of: Investigation of the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266, Order (July 17, 2003). The Commission determined in late May 2006 that ongoing MISO membership was not likely to provide ongoing net benefits to customers and authorized the Companies to terminate their MISO membership. Case No. 2003-00266, Order (May 31, 2006).

they currently have an obligation to file an annual RTO analysis.[18] The Companies filed their 2020 RTO Membership Analysis with the Commission on March 31, 2020.[19] The Companies are filing this updated analysis contemporaneously with their IRP filing in accordance the Commission's February 18, 2021 and March 22, 2021 Orders in Case Nos. 2018-00294 and 2018-00295. This report is modeled after the Companies' previous RTO Membership Analyses and updated to reflect the best available data at the time of this analysis.

5 Methodology

Consistent with the Companies' IRP, this analysis is through 2036. After reviewing the methodology used in the two most recent RTO Membership Analyses and the status of recent developments in the RTOs, the Companies determined that it was appropriate to use the same methodology as was used in the prior analyses for the near term, with updates to the different components to reflect RTO operational changes and other new information for 2023 through 2027. For this period, the analysis focuses on estimating the net financial impact to customers by comparing the standalone operations of LG&E and KU to estimated incremental benefits and costs of RTO membership. As with prior analyses, the team developed and studied three scenarios using different projections and assumptions to provide a range of potential outcomes.[20] The High Case uses assumptions most supportive of RTO membership, such as lower administration costs, higher energy and capacity prices, and lower transmission expansion costs. The Mid Case uses assumptions and forecasts reflective of mid-range assumptions using published forecasts for administration costs, mid-range market energy and capacity prices, and transmission expansion costs based on published MISO rates and the use of a neighboring PJM utility as a proxy. The Low Case captures the downside risk of RTO membership uncertainty by assuming low market energy and capacity prices, and higher costs. Appendix A contains

[18] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order at 29-30 (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order at 33 (Ky. PSC Apr. 30, 2019).
[19] In accordance with the Commission's April 30, 2019 Orders in Case Nos. 2018-00294 and 2018-00295, the Companies filed their 2020 RTO Membership Analysis in the post-case correspondence of those proceedings.
[20] Although the scenarios apply the underlying assumptions across all years, it is possible that actual performance across the analysis period could be of mixed results with some years more consistent with the High Case, with others more consistent with the Low or Mid Case. In other words, the purpose of the three cases is to provide a reasonable range of possible outcomes across the analysis period, not to say that there are only three sets of possible outcomes.

a description of the methodology used to develop the underlying assumptions that differ between the three scenarios.

Beginning in 2028, when this analysis assumes Mill Creek 2 and Brown 3 will be retired, the analysis considers the projected range of the fixed cost components of RTO membership and focuses on the new market risk profile of the Companies as more generating units retire and customers are subject to increasing market exposure.

6 Key Assumptions

- The period of the analysis is 2023 through 2036. This 14-year term is slightly longer than the term used in the 2020 analysis to provide alignment with the time horizon of the IRP.
- The total financial impact of Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), and congestion costs over the analysis period have net zero cost. When the Companies were MISO members, the congestion management strategy was to hedge congestion costs, seeking to minimize such costs and not speculate. It is assumed this will be the approach if the Companies were RTO members in the future.
- The purchase or sale of ancillary services has net zero cost because the Companies are both buyers and sellers of these products and any charges are offset by credits. This assumption is consistent with other analyses provided to the Commission.
- The Companies estimated potential energy market benefits and costs using their commodity price forecasts, generation available for sales, and native load forecast used for annual business planning and the 2021 IRP.
- The Companies did not use generator-specific or load-specific Locational Marginal Pricing ("LMP") models but used forecasts for market energy prices at the Companies' interfaces with MISO and PJM.
- The Companies assumed retirements of the Companies' generating units to occur according to the units' depreciable lives, except for Mill Creek Unit 1, which is assumed to retire in 2024, and Mill Creek Unit 2 and Brown Unit 3, which are assumed to retire in 2028. Ghent Units 1 and 2 and Brown Unit 9 are assumed to retire in 2034; Brown Units 8 and 10 are assumed to retire in 2035; Brown Unit 11 is assumed to retire in 2036. These assumptions are consistent with the Companies' 2021 IRP.
- The analysis does not attempt to address how the retirements of existing units would be replaced by new generation resources in the case of RTO membership. Instead, starting with the Companies' assumed capacity need in 2028 (with base load), it evaluates the fixed costs of RTO membership and contemplates the market energy

and capacity risk exposure and potential mitigation methods. In an RTO, the Companies would no longer be focused on matching generation to load but would rely on the RTO for reliability. If the Companies were to join an RTO, they would need to evaluate the market energy and capacity price risk to customers of participating in these markets and consider an appropriate hedging strategy to mitigate this risk. This analysis does not incorporate any optimization of such a hedging strategy.

- The analysis focuses on impacts to the Companies' native load customers only and not third-party generators, loads, or other potentially impacted parties.
- Quantifiable items do not include any value adjustments to account for potential future changes in policy or market rules.
- Generating capacity above the RTO Planning Reserve Margin results in a benefit and is quantified in the Capacity Market Benefits. Capacity below the Planning Reserve margin would result in a cost.
- Uplift costs are based on RTOs' estimates of costs to load.
- Some reallocation of human resources is assumed to be necessary, but it is assumed that there is no incremental change in overall headcount attributable to joining an RTO.
- No financial impacts from deviations between day-ahead and real-time energy markets, operations, and load are included in the analysis.

7 RTO Cost Components

7.1 Allocation of Transmission Expansion Costs

Transmission planning and the allocation of expansion costs are major activities for each RTO. A significant cost in this analysis is the allocation of transmission expansion costs allocated to RTO members' load.

- For MISO membership, the Companies' annual costs were estimated to range from $45 million to $53 million in the Mid Case.[21]
- For PJM membership, the Companies' annual transmission expansion costs were estimated to range from $17 million to $19 million in the Mid Case.

7.1.1 MISO

Under current MISO policy, the cost of a new transmission project that addresses energy policy or provides widespread benefits across the footprint is considered a "Multi-Value

[21] These estimates do not include anticipated allocation of costs for transmission expansion projects currently being considered by MISO in its Long-Range Transmission Plan (LRTP) process.

Project" ("MVP"). The cost of MVPs is allocated 100% to load in the northern and central regions of MISO using a "postage stamp" methodology—i.e., all members' load pays the same rate for the MVP irrespective of where the load is located in the applicable footprint—and are recovered under Schedule 26A of the MISO Tariff. The Companies' estimated share of the roughly $6.6 billion in MVP projects currently approved in the MISO Transmission Expansion Plan ("MTEP") is based on the "indicative annual charges for approved MVP" published on the MISO website applied to the Companies' forecasted loads.[22]

For the High Case, the annual expansion costs were not changed from the Mid Case because the vast majority of the existing MVPs, which were approved as a portfolio in 2011, have been completed, which eliminates any rationale for assuming a reduced expansion cost. For the Low Case, the transmission expansion costs were assumed to increase 14.8% per year over the first 10 years of RTO membership, and remain level thereafter to simulate a quadrupling of the Mid Case cost based on the impact of the anticipated significant transmission build out as discussed below.

As part of its Reliability Imperative initiative, MISO determined that the generation resource evolution and electrification represented in its Futures analysis necessitated a "Long-Range Transmission Plan" (LRTP) to identify needed transmission solutions. This effort is, in large part, in response to expected nation-wide grid expansion needs to accommodate renewable generation. MISO developed an initial transmission roadmap to indicate the expected scope of significant long-range transmission needs in its Futures 1, 2, and 3 planning scenarios and is currently in the process of identifying possible transmission projects through the LRTP for inclusion and approval in Appendix A of the annual MISO Transmission Expansion Plan (MTEP). MISO intends to identify such LRTP projects while analyses, business cases, and cost allocation are developed. Although projects identified in the LRTP are not initially designated for cost allocation purposes prior to approval in the MTEP, it is likely under current MISO cost allocation rules[23] that they will be regionally, rather than locally, allocated to members' load.

7.1.2 PJM

Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculation. These

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[22] https://www.misoenergy.org/planning/planning/schedule-26-and-26a-indicative-reports/

[23] MISO and its stakeholders are currently discussing through its Regional Expansion Criteria and Benefits (RECB) Working Group forum various potential cost allocation methodologies, both existing and new, to be applied to Future 1 transmission expansion projects identified in the LRTP.

charges are recovered under Schedule 12 of the PJM tariff. The Companies estimated their allocation for projects documented in the RTEP within this analysis period using PJM's publicly posted RTEP project information. As was done for the 2020 RTO Membership Analysis, in this analysis the Companies used PJM's most-current RTEP project information (2020). There were significant differences in the cost allocation in PJM's 2020 information as compared to the 2019 data provided by PJM and used in the Companies' 2020 RTO Membership Analysis, in particular PJM's approval and allocation of a $288 million transmission project in Virginia in 2020.[24] Because of the changes made in the cost allocations in the updated information from PJM, this analysis reflects a sizeable increase in the projected transmission expansion costs associated with PJM membership, which also demonstrates the increased uncertainty caused by cost allocation methodologies in larger-scale regional RTO footprints.

In developing the Low and High cases, the Companies used the same variance assumptions for PJM as applied concerning MISO. The annual expansion costs were not changed from the Mid Case to assign a value for the High Case and increased by 14.8% per year from the Mid Case to assign a value to the Low Case. This is based on similar potential in PJM for large-scale transmission buildout in response to expected nation-wide grid expansion needs to accommodate renewable generation. The cost allocation for RTEP projects in PJM is subject to the potential for periodic revision and reallocation based on changes in flow and other cost allocation factors.[25]

7.2 Administrative Charges

MISO and PJM have various tariff schedules to recover the administrative cost of operating the markets and providing services to their respective members.

MISO forecasts annual administrative rate increases between 3% and 5%. MISO annual cost in the Mid Case is $14.8 million beginning in 2023 and increases to $24.1 million by 2036. MISO's 2020 forecasted administrative rate for 2021 was escalated 4% each year and then applied to the Companies' annual load forecast to estimate annual MISO administration expense. The administration rates are based on cost projections contained in MISO's 2020 revenue requirement forecast.

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[24] To estimate transmission expansion costs that the Companies would expect to be allocated as a member of PJM, the Companies used EKPC's 2020 transmission expansion allocation and adjusted appropriately to account for differences between Companies' load and EPKC's load.

[25] *See e.g.*, Linden VFT, LLC v. PJM Interconnection, L.L.C., 170 FERC ¶ 61,123 (2020), in which FERC denied a complaint filed by Linden VFT, LLC challenging revised cost allocation for two projects following the termination of Consolidated Edison Company of New York, Inc.'s transmission service agreements that resulted in an alleged increase in costs from $10 million to approximately $132 million.

PJM annual cost in the Mid Case is $18 million beginning in 2023 and increases to $24.2 million by 2036. The Companies based these estimates on 2020 state-of-the-market reports submitted by PJM's market monitor. The 2020 rates were then escalated 2.5% each year. PJM's administrative cost rates have increased by an average of 1.9% per year from 2015 through 2020, in line with PJM's expected rate of around 2.5%.

Although revenue requirements for administrative costs are expected to increase around 1% to 5% each year, the average cost to load can be more volatile, driven by the amount of load (weather and demand dependent) and the number of customers to allocate expense, which can vary by RTO membership entries and exits. Results from prior years have shown double-digit year-over-year changes at times to the cost per MWh to load, both positive and negative, e.g., ranging from 17% lower to 15% higher. To reflect forecast rate volatility compared to Mid Case results, the annual administration costs were reduced by 20% from the Mid Case to assign a value for the High Case and increased by 20% from the Mid Case to assign a value to the Low Case.

7.3 Uplift Costs

MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, these costs for both RTOs are the result of committing units in real-time that were not committed in the day-ahead market. MISO refers to uplift costs as "revenue sufficiency guarantee" ("RSG") costs; PJM refers to such costs as "balancing operating reserve" ("BOR") expense. Uplift expense for MISO is expected to average around $7.5 million per year, while PJM uplift is expected to average just under $5 million per year. Rates are based on state-of-the-market reports submitted by each RTO's market monitor.

Although uplift costs have declined compared to 2014, there remains a risk of material additional cost assignment driven by extreme weather events and unplanned outage risk.

In 2014 PJM collected $960 million in uplift, with an average cost to load of $1.15 per MWh. PJM then took steps to address issues contributing to uplift, including implementation of enhanced testing requirements for generators receiving capacity payments, increased penalties for non-performance, and the shift of reserve capacity from the West Region to the East. As a result, in 2015 uplift cost declined 67% to $0.38 per MWh and then saw another 55% decrease in 2016 to $0.17 per MWh. While the 2017 cost was $0.14 per MWh, expense increased to $0.23 per MWh in 2018 but then declined to $0.11 per MWh for 2019 before increasing slightly to $0.12 per MWh in 2020. The Companies used an average rate of $0.15 for this study to account for potential market volatility. The rate is the average of 2018 through 2020.

MISO uplift costs have also decreased compared to 2014, although on a less extreme and more stable basis as compared to PJM, resulting from a combination of RTO improvements related to cost causation and lower fuel expense. Uplift cost of $0.40 per MWh to load in 2014 declined to $0.22 per MWh in 2015 and then decreased further to $0.20 in 2016. MISO's 2017 cost increased to $0.25 per MWh, decreased to $0.23 per MWh in 2018, and then decreased again to $0.18 per MWh in 2019. However, in 2020 the Uplift cost rose to $0.31 per MWh, the highest since 2014. The Companies used the rate of $0.24 per MWh, the average of 2018 through 2020 MISO uplift costs, to be consistent with the period used in PJM's analysis.

Planning for and managing through extreme weather and unplanned outage events is difficult, particularly because the response would be directed by the RTO juggling resource, market, and other considerations over a wide area. Therefore, uplift costs are a potentially material expense risk for RTO participants.

7.4 Lost Transmission Revenue

The analysis reflects an expected decrease in the sale of point-to-point transmission service resulting from RTO membership as the Companies would be under the RTO tariff and not offer point-to-point transmission service directly. The lost transmission revenue included in this analysis ranges from $1.2 to $2.7 million.

7.5 Lost Joint Party Settlement Revenue

An additional $1.4 to $1.9 million of lost revenue was also included because of the existing settlement agreement between MISO, SPP, and the Joint Parties (including the Companies). The settlement agreement addressed issues identified by SPP and the Joint Parties that arose from MISO's southern expansion to include Entergy and operate as a single Balancing Authority Area. Under the settlement agreement, MISO compensates SPP and the Joint Parties for the use of these parties' systems. It is not clear that the Joint Parties agreement as applied to the Companies would terminate as a result of RTO membership, but the Companies determined that it was reasonable to assume for the purposes of this analysis that compensation to the Companies under the settlement agreement would stop if the Companies were to integrate into MISO or PJM. The Companies did not include in this analysis an assumption that if they were to join MISO, they would potentially be asked to contribute an as-yet unknown amount to the compensation paid by MISO to SPP and the Joint Parties.

7.6 Implementation Costs

The Companies would incur costs to fully integrate their operations into an RTO. For the purpose of this updated analysis, the Companies assumed that these costs would be approximately $1 million per year for additional metering hardware and software required by RTOs. It should be noted though that the stability of these costs is also uncertain as RTO initiatives impacting metering requirements and computer hardware and software enhancements develop.

8 RTO Benefit Components

8.1 Capacity

Joining an RTO has significant implications for the Companies' future capacity profile. A primary benefit of RTO membership is the ability to share capacity across a diverse collective load profile, which allows for a lower need for collective reserves compared to the total reserves that would be required for each entity individually. The Companies evaluated the RTO capacity impact through 2027 by modeling the benefit of selling capacity in the RTO capacity markets.

8.1.1 Capacity Market Benefits and Costs[26]

As an initial matter, the performance of an analysis of potential capacity auction benefits for either RTO must come with a significant caveat that the capacity market constructs for both RTOs remain in flux.

A protracted dispute over PJM's minimum offer price rule (MOPR) resulted in a lengthy suspension of the PJM planning year 2023/2024 capacity auction. PJM filed tariff modifications and auction timelines on March 18, 2020 in response to FERC's order to modify the MOPR rules. PJM proposed changes to the capacity market and in October 2020 FERC approved PJM's plans. However, significant opposition to the proposed changes remained as many PJM stakeholders believed the MOPR rules remained intact. Maryland and New Jersey reportedly considered exiting the capacity market altogether. In response, PJM initiated a stakeholder process to comprehensively revise the MOPR, resulting in new rules that exempted renewable energy facilities, new natural gas facilities, and nuclear power plants. The new rules went into effect on September 29, 2021 when FERC failed to reach a decision on a 2-2 split vote.

In a separate matter, on October 4, 2021 PJM submitted a request for rehearing to FERC regarding a September 2, 2021 FERC order establishing new capacity market seller offer cap (MSOC) rules. The new offer cap would limit capacity bids to the "unit-specific net avoidable cost rate" and would take effect in the January 2022 capacity auction. It is highly

[26] While this cost-benefit analysis is based upon RTO membership, membership is not required to participate in PJM or MISO capacity markets.

uncertain as to whether the new rules will stand. PJM questioned the feasibility of the new offer cap methodology and broad opposition exists amongst generators in PJM.

MISO has identified several projects to "redefine markets" as a part of its "MISO Forward" report and integrated road map. For example, MISO's Resource Availability and Need ("RAN") initiative alone is exploring several potential modifications to MISO market design, resource requirements, and incentives that may or may not come to fruition during the period studied in this analysis.

The state of uncertainty and evolution for both markets means there is inadequate information available to consider all possible future market construct changes into the updated analysis. As such, the Companies used the same general methodology for evaluating capacity auction impacts as was used in the 2020 RTO Membership Analysis.

Both PJM and MISO take the position that they can provide appropriate generation reliability with a lower target annual peak reserve margin as compared to the Companies' target summer reserve margin range of 17 percent to 25 percent. Therefore, to the extent that the Companies forecast their reserve margin to be above the RTO target, the potential exists to sell capacity (net of their capacity needs for load) into the RTO capacity auctions. However, after the retirement of the Companies' generating units occur, the Companies expect to be a net purchaser of capacity from the RTO. This analysis evaluates the potential value or cost of capacity sales and purchases in both the PJM and MISO capacity market constructs assuming the following:

- Forecasted low, mid, and high peak demand based on normal weather and a range of forecast assumptions consistent with the 2021 IRP,
- The difference between the Companies' generating capacity and each RTO's forecasted load obligation is assessed for net sales or purchases in the RTO capacity market,
- The Companies' capacity offered into the capacity market may not clear at 100 percent, and
- Capacity pricing that considers the median of historical auction results.

Inputs to this analysis are sensitive to these assumptions and deviations would result in material impacts to the projected results.

8.1.2 PJM Reliability Pricing Model ("RPM")

Inputs to estimating the value of the PJM capacity market are as follows:

- Installed Capacity ("ICAP") [27] – excludes small-frame combustion turbines, [28] Curtailable Service Rider ("CSR") load, and Demand Conservation Program ("DCP"),[29] but includes capacity available through the Companies' ownership share of Ohio Valley Electric Corporation ("OVEC").
- Unforced Capacity ("UCAP")[30] – calculated by adjusting ICAP for the business plan forced outage and maintenance outage rates for coal and natural gas units. Hydro and solar units were adjusted using PJM's specified ELCC Class Ratings for intermittent resources.[31]
- Cleared Capacity – three levels of capacity clearance rate were considered based on PJM's historical capacity clearance rate by fuel type.
- Capacity Need – based on the Companies' joint system peak load forecast, adjusted for 1) historical average peak diversity between LG&E and KU and PJM RTO and 2) PJM's applicable Forecast Pool Requirement factor.
- Capacity Price – reflects the median historical base residual auction price since the 2016/2017 planning year of $100/MW-day, which occurred for the 2019/2020 planning year.

8.1.3 The MISO Planning Resource Auction ("PRA")

Inputs to estimating the value of the MISO capacity market to the Companies are as follows:

- ICAP – excludes small-frame combustion turbines, CSR load and DCP,[32] but includes capacity available through the Companies' ownership share of OVEC.

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[27] ICAP is defined by RTOs as a unit's net summer capability.

[28] The Companies have four small-frame natural gas-fired peaking units. Because of their age, the Companies plan to limit spending on the small-frame SCCTs and retire the units when significant investment is needed for their continued operation.

[29] CSR load reduction was excluded due to uncertainty as to whether rights under the retail CSR tariff would be consistent with RTO capacity performance obligations. DLC load reduction is seasonal and therefore does not appear to meet RTO capacity performance requirements.

[30] Unforced capacity is defined as installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating. For this analysis, Unforced Capacity is calculated as the Installed Capacity adjusted for 5-year average $EFOR_d$ plus 25% of EMOR or UCAP=ICAP*[1-(EFORd+0.25*EMOR)].

[31] PJM ELCC Class Ratings; *see*: https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx.

[32] CSR and DCP load reductions were excluded due to uncertainty as to whether these retail programs would be consistent with MISO tariff requirements.

- UCAP – same as PJM UCAP input for coal, natural gas, hydro, and fixed-panel solar units. Tracking-panel solar units were adjusted using MISO's specified capacity credits for solar resources.[33]
- Cleared Capacity – capacity bid is assumed to clear the auction using a range of MISO's Zone 6 historical clearance rates for all resource types.[34]
- Capacity Need – based on the Companies' joint system peak load forecast adjusted for 1) historical average peak diversity between LG&E and KU and MISO, 2) MISO's UCAP planning reserve margin, and 3) MISO's transmission loss factor.
- Capacity Price – reflects the median historical capacity auction price since the 2016/2017 planning year of $5/MW-day, which occurred for MISO's two most recent planning years of 2020/2021 and 2021/2022.

8.1.4 Capacity Market Financial Impacts

For both RTOs, capacity net sales and purchases are estimated as a function of cleared UCAP minus RTO Capacity Need. If resources are not fully replaced as units retire over the review period, installed capacity, and consequently unforced capacity, declines through the period. Peak loads are relatively flat across the period. As a result, it is likely that in the near term, the Companies would have capacity above the amount they would need to purchase to serve load, which would be available to offer into each RTO's capacity auction, although the level of availability differs due to each RTO's reserve margin requirements. As existing resources retire and are assumed to be replaced with solar resources to meet the RTOs' minimum reliability levels, the Companies would be in a net purchasing position to the extent their portfolio did not clear the annual capacity auction.

Even when the Companies may have capacity available to offer in each market, PJM has a rate of capacity clearance by fuel type that varies from year to year but is less than 100% of the capacity offered into the market. For example, coal capacity clearing the auction has ranged from 81% to 91% of coal capacity offered since the 2016/2017 auction. For natural gas capacity, this range is 92% to 98%.

MISO data on capacity clearance rates is not provided with the granularity of PJM data, so clearance rates could not be applied by fuel type; however, clearance data provided by zone indicates nearly 100% of all offered resources have cleared the auction for Zone 6, which is adjacent to the Companies' service area, since 2016. A range of historical

[33] MISO wind and solar capacity credit; See: https://cdn.misoenergy.org/2021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf.
[34] MISO data summarized at the zonal level without specificity by fuel type.

capacity clearance rates since 2016/2017 was applied to all resources in each of the cases analyzed.

Across all cases, the calculated annual capacity impact for PJM's RPM ranges from ($7) million to $23 million annually in 2023 through 2027. For MISO, with typically significantly lower capacity auction clearing prices but higher resource clearing rates, the calculated annual capacity market impact ranges from $1 million to $1.7 million across all cases.

8.1.5 Performance Risks

PJM has established stringent Capacity Performance ("CP") requirements for generator performance. All generation capacity resources that are capable or can reasonably become capable of qualifying as CP resources must be offered into the capacity market as CP resources. Exceptions are permitted if the seller can demonstrate that a resource is reasonably expected to be physically incapable of meeting CP requirements. A resource that requires substantial investment to qualify as a CP resource is not excused from the CP must-offer requirement but is expected to include such costs in its CP sell offer.

Generators must be capable of sustained, predictable operation that allows the resource to be available to provide energy and reserves during performance assessment hours throughout the Delivery Year. Penalties are applied when actual performance is less than expected performance. The non-performance charge rate for capacity performance is a function of the net cost of new entry ("CONE") for the delivery area in which the resource is located, based upon PJM's modeling. For 2022/2023, this rate is estimated to be $3,169 per MWh.[35] For example, one hour of unplanned outage for the Companies' natural gas combined cycle with a UCAP of 632 MW could result in a non-performance charge of more than $2 million.[36]

MISO has not designated capacity performance requirements in the same manner as PJM; however, Planning Resources are obligated to provide capacity to their designated zone for the entire planning year, as well as to perform during system emergencies.[37] If a load-serving entity does not achieve resource adequacy for the planning year, a capacity deficiency charge will be assessed based upon 2.748 times the CONE. MISO's CONE for Zone 6 for the 2021/2022 planning year is $244.16 per MW-day.[38] Though this analysis

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[35] Non-Performance Charge Rate estimated using the value of net CONE for PJM RTO.

[36] Non-Performance Charge = Performance Shortfall MW *Non-Performance Charge Rate

[37] A resource may be designated as a Planning Resource either through the MISO PRA or as part of a fixed resource adequacy plan for a load serving entity (LSE). Only Planning resources cleared through the PRA are subject to capacity credits and penalties.

[38] Non-Performance Charge Rate estimated using the value of net CONE for MISO Zone 6.

does not quantify these non-performance charges, the risk associated with non-performance is significant.

8.2 Energy Market Benefits and Costs

The Companies estimated energy market benefits and costs using the Companies' existing planning models. These models are of the Companies' system; they are not RTO-wide regional models. An analysis using a complete RTO-wide regional market model would be advisable before making any decision to join an RTO based on expected energy market benefits and costs.

The Companies used their production cost software tool, PROSYM, to forecast the potential energy market benefits and costs of joining an RTO by estimating the potential net impacts to (1) market energy purchase costs for retail and wholesale requirements customers and (2) market energy sales margins, using a base load forecast and a range of commodity price forecasts. The following model revisions were made to PROSYM to reflect RTO membership.

- Dispatching/selling generating units into the RTO energy market and purchasing native load energy from the RTO energy market.
- The Companies' normal business plan assumptions include constraints on starting combustion turbines for the sole purpose of making market sales to model the typical dispatch of these units. The analysis of RTO membership eliminated these constraints on dispatch because the RTO would be directing dispatch decisions.
- The Companies' assumption for the spinning reserve requirement was reduced from 327 MW in the business plan to 220 MW in the RTO analysis based on the Companies' projected load ratio share of the estimated spinning reserve requirements in the RTO.
- The Companies eliminated several expenses applied to market sales and purchases in the Companies' current business plan.
    - **RTO expenses**. RTO balancing operating reserve charges on sales and purchases are included in the business plan to cover deviations between the day-ahead and real-time market. The average of these RTO expenses that were eliminated in the RTO analysis over the study period were assumed to be \$0.39/MWh with an average annual increase of 2%. Initial RTO expenses (Peak: \$0.42/MWh, Off-Peak: \$0.38/MWh, Weekend: \$0.26/MWh) were in 2021 dollars based on recent historical averages.
    - **RTO transmission**. RTOs charge for transmission to "drive-out" energy from the RTO footprint for expenses for purchases made by the Companies. The average of these RTO transmission charges that were eliminated in the RTO

analysis over the study period were assumed to be $1.51/MWh with an average annual increase of 1%. Initial RTO transmission rates (Peak: $1.4/MWh, Off-Peak: $1.4/MWh, Weekend: $1.4/MWh) were in 2021 dollars and reflect the current rates as of the 2022 business plan.

- **LG&E-KU transmission.** The Companies also charge for transmission for market sales made by the Companies. The average of these transmission charges that were eliminated in the RTO analysis over the study period were assumed to be $6.55/MWh with an average annual increase of 1%. Initial LG&E-KU transmission rates (Peak: $8.31/MWh, Off-Peak: $4.04/MWh, Weekend: $4.04/MWh) were in 2021 dollars and reflect the current rates in the 2022 Business Plan.
- **Losses**. When generating energy for market sales, the Companies must generate additional electricity above the transacted volume to compensate for losses on the transmission lines. The Companies' 2020 Business Plan estimated the cost associated with losses to be 0.5% of the fuel cost to generate the energy sold. In an RTO, the Companies' generation would be sold at the generator bus versus the RTO interface. The RTO analysis assumes that over the study period the average cost of losses eliminated is $0.1/MWh with an average annual increase of 1.5%.
- **Market price buffer**. To manage the uncertainty that exists between real-time market electricity prices and aggregated hourly settled prices, the Companies' normal business plan assumes that energy sales and purchases will not be transacted unless a minimum of a $5/MWh hurdle can be achieved. Under the RTO analysis, this hurdle rate is eliminated.

The PJM and MISO analyses used a range of commodity prices: low, mid, and high fuel price forecasts for the Companies' generation units and the corresponding low, mid, and high electricity price forecasts specific to each RTO. Table 3 summarizes the minimum and maximum estimated annual net energy market benefits and costs for the 2023-2027 period for each commodity price forecast. The net energy market impact figures reflect the sum of (1) the potential favorable incremental benefits of selling energy into the RTO market and (2) the potential incremental costs or benefits of purchasing market-priced energy for the Companies' retail and wholesale requirements customers, relative to non-RTO membership.[39]

[39] Appendix C shows the annual benefits and costs of each of these components for each scenario.

Table 3: Range of Annual Net Energy Market Benefits, 2023-2027 ($M)

Commodity Prices	Low	Mid	High
MISO	15-21	7-10	12-16
PJM	16-21	7-10	10-14

In all scenarios, the estimated benefit of additional energy sales margin was greater than the additional cost of purchasing market energy for native load through 2027. These benefits represent about 1-3% of the total native load cost of $670 to $840 million per year in these scenarios. The value is highly dependent on energy market prices, which can be volatile at times. As noted in the Companies' prior RTO analyses, energy market impact estimates are highly uncertain as they depend on the level of market electricity prices, which directly depend on many uncertain variables including fuel prices, weather, and RTO-wide load and generation capacity and performance. They may also be indirectly influenced by many external factors, including state and federal policy.

Figure 10 and Figure 11 display the ranges of market energy price forecasts used in the near-term analysis for MISO and PJM.

Figure 10: MISO Energy Price Forecast Scenarios (Nominal Annual Average $/MWh)

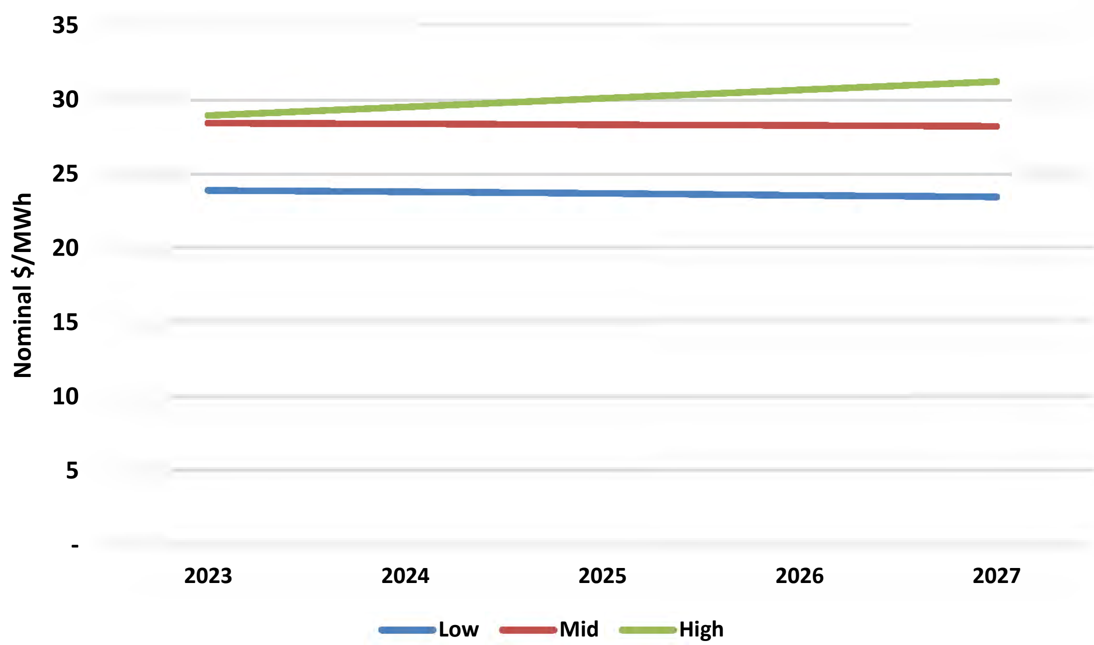
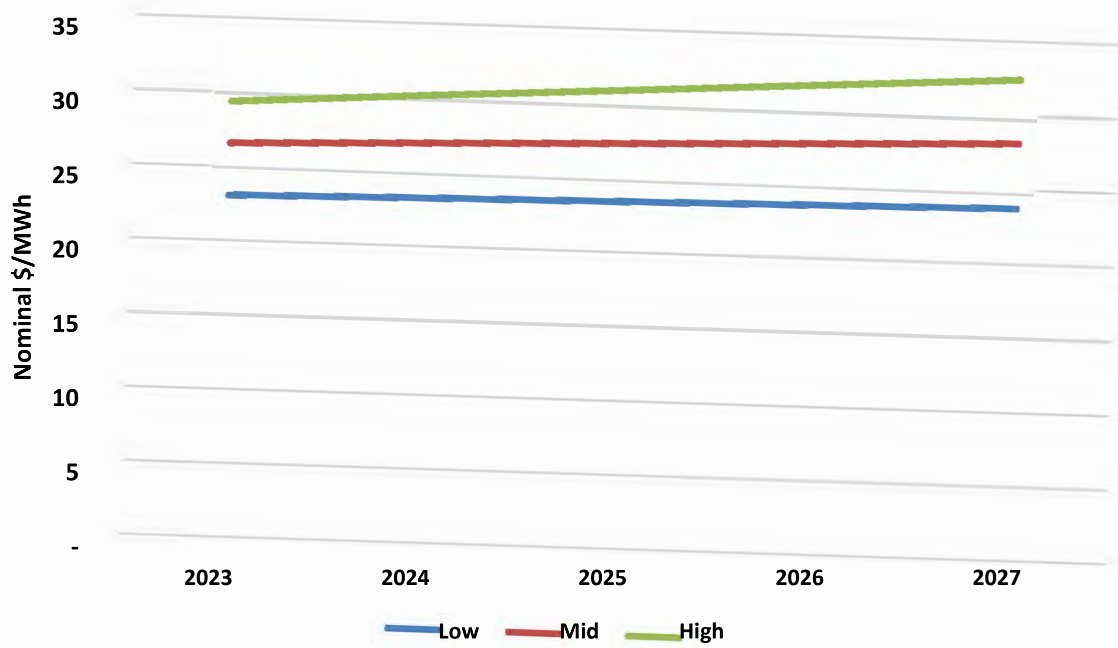


Figure 11: PJM Energy Price Forecast Scenarios (Nominal Annual Average $/MWh)



8.3 Transmission Revenue

In both MISO and PJM, the Companies would have a "zonal" transmission rate that would be calculated in a similar fashion to how their transmission rate is calculated currently with the Companies as stand-alone transmission providers. In an RTO, the zonal transmission rate would apply to any Network or Point-to-Point ("PTP") transmission that sinks in the zone and the rate would continue to be based on the Companies' transmission revenue requirements.

The Companies would also potentially receive an allocation of revenues from each RTO based on the revenues that each RTO collects for PTP transmission service that does not sink within the RTO (i.e., drive-out and drive-through transmission service). Both PJM and MISO have a mechanism for this allocation based on combinations of transmission plant in service ratio and flow-based derivations. Due to the difficulties in projecting drive-through and drive-out transmission use as well as flows and ratios that would drive the Companies' allocation of revenues, the Companies did not attempt to determine the potential projected value of this allocation and therefore did not include it in this analysis. When the Companies were previously members of MISO, revenues for drive-through and drive-out transmission use were around $1M annually. Due to the passage of time and changes in transmission facilities and use since the Companies' exit, the Companies did not use this historical performance value as a proxy but do believe it indicates that revenue from this service is not likely to be significant.

8.4 **FERC Charges**

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as the Companies are assessed outside of an RTO. For this analysis, the projected FERC assessment charges were included in RTO administrative charges. The amount that the Companies currently pay is included as a projected benefit to quantify properly the net change in cost.

8.5 **Eliminated Administration Charges**

Membership in either PJM or MISO would result in cost savings from the elimination of certain third-party services. For the purposes of this analysis, the Companies assumed they would no longer need the current Independent Transmission Organization ("ITO") or Reliability Coordinator ("RC") services provided by TranServ and TVA, respectively. In addition, the analysis assumes the current reserve-sharing contract with TVA would no longer be needed.

8.6 **Elimination of De-Pancaking Expense**

The Companies currently provide MMD credits to certain entities importing from MISO.[40] The Companies assumed all credits for MISO charges and waiving of their transmission charges would cease if they joined MISO and all but MISO Schedule 26A would be eliminated if the Companies joined PJM.[41] The benefit amount from eliminating MMD expense is based on such expenses included in the Business Plan and allocated to LG&E and KU retail and wholesale customers. For the High Case, the depancaking expenses were increased by 20% to account for potential increase in the MISO drive-out rate. For the Low Case, the depancaking expenses were assumed to increase to align with the increased MISO transmission expansion cost that is assumed in the Low Case. This results

[40] The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. *See*, *E.ON U.S., LLC, et al.*, Docket No. ER06-1279-000. The Companies received FERC approval to eliminate this obligation, but subject to the implementation of a transition mechanism for certain power supply arrangements. The transition mechanism is currently in effect, under which the Companies must still provide certain credits for MISO transmission charges, but the details of such transition mechanism are still under litigation. *See*, FERC Docket Nos. EC98-2-001, ER18-2162-000, EC98-2-002, ER18-2162-001, ER19-2396-000, ER19-2397-000, ER19-2396-001, ER19- 2397-001, EC98-2-003, ER18-2162-002, EC98-2-004, ER18-2162-003, ER19-2396-002, ER19-2397-002 and D.C. Circuit Court of Appeals Docket Nos. 19-1236, 19-1237, 20-1282, 20-1326, 20-1452, 20-1459, 21-1013, 21-1025 (consolidated).

[41] FERC has required that transmission across the MISO-PJM be depancaked through the use of license plate rates. An exception to this general depancaking rule was created for MISO Schedule 26A in 2016. *See*, *Midwest Independent Transmission System Operator, Inc.*, 156 FERC ¶61,034 (2016) (Order on Remand from the Seventh Circuit finding that, in light of current conditions, the limitation on export pricing to PJM is no longer justified for MISO Schedule 26A charges.)

in slightly higher annual depancaking expense in the Low Case ranging from 2% to 29% year over year from the Mid Case.

9 Near-Term Quantitative Results

The Companies developed a range of results reflecting low, mid, and high favorability for joining each RTO through 2027. The high-favorability cases reflect the combinations of benefit/cost items that result in the most RTO favorability. The low and mid-favorability cases were developed similarly to demonstrate a broad range of reasonable uncertainty. Appendix A details the assumptions that were included in each favorability case. Figure 12 and Figure 13 display the values for all three favorability cases by year for both MISO and PJM (See Appendix B for detailed annual values).

Figure 12: MISO Range of Near-Term Potential Outcomes ($M)

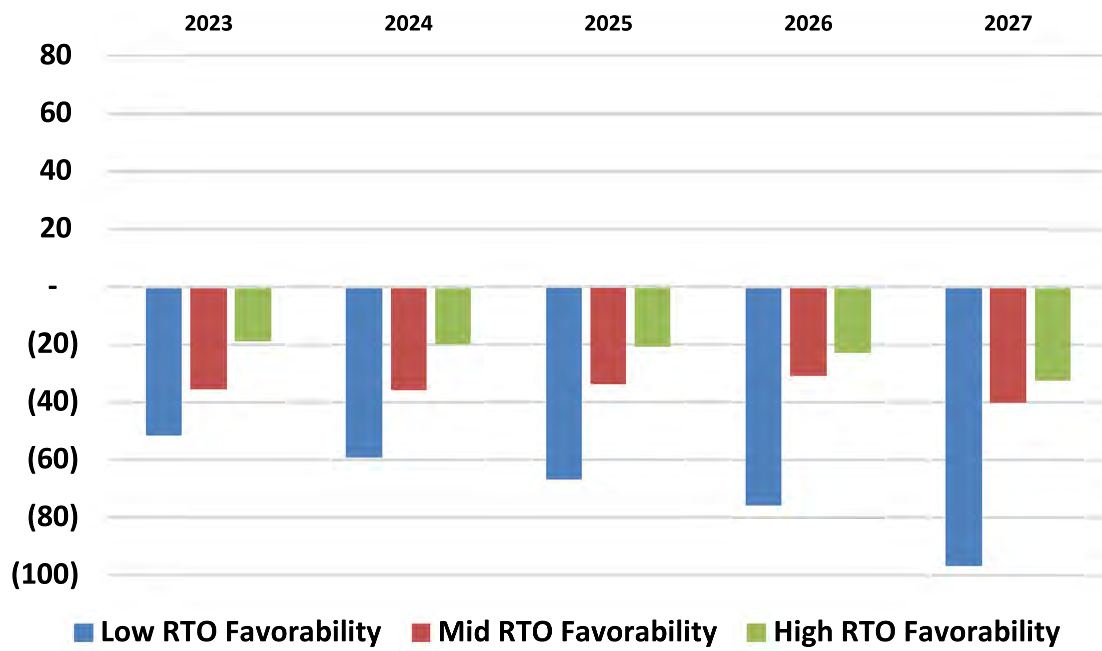
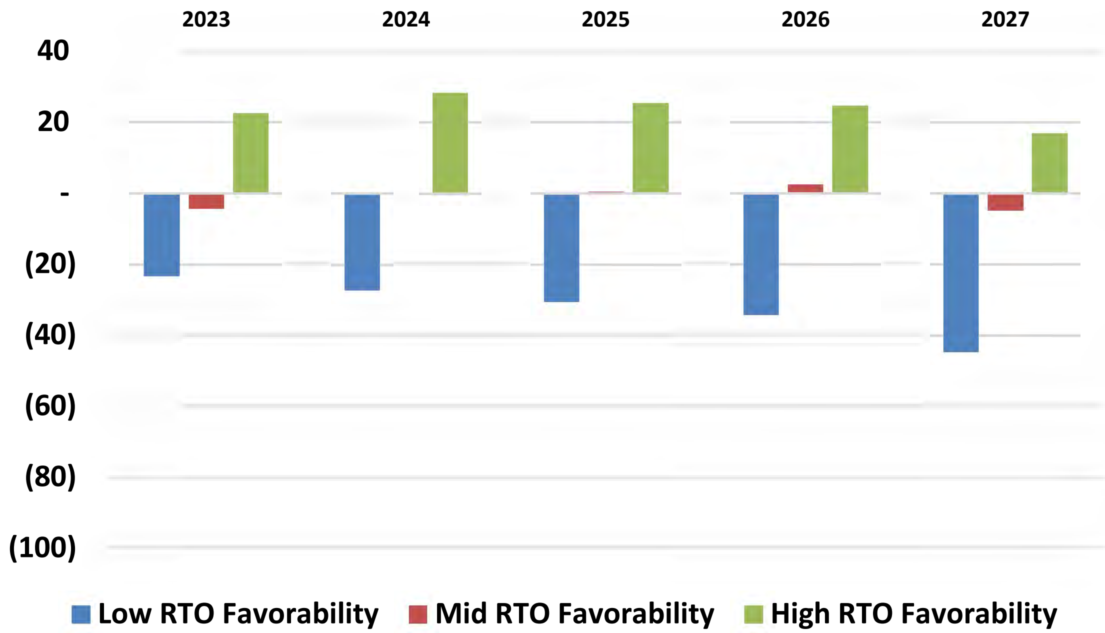


Figure 13: PJM Range of Potential Near-Term Outcomes ($M)



Before 2028, the projected potential net benefits and costs of joining an RTO are mixed. While the cases shown present discrete views for RTO membership favorability, they are intended to represent the distribution of potential outcomes. The green bars represent the high-favorability case, which is the combination of assumptions that results in the most favorable case for RTO membership in each year. The blue bars represent the least favorable combination of assumptions in each year. The red bars represent a case with mid-level assumptions. As the figures show, joining MISO is unfavorable in each year in all cases. The analysis for joining PJM is a bit more mixed with the high case showing the potential for savings and the mid case near zero (ranging between $4 million unfavorable and $2 million favorable). This difference is due primarily to the lower transmission expansion costs and higher forecasted capacity prices in PJM compared to MISO.

PJM's high-favorability case ranges between $22 million and $28 million more favorable than the mid-case. Achieving this high favorability in the RTO requires the alignment of favorable assumptions for several of the cost and benefit components. Table 4 shows the annual variance between the mid-favorability case and the high-favorability case for each of these variable components.

Table 4: Variances between PJM High and Mid-Favorability Cases ($M)

	2023	2024	2025	2026	2027
Lower Admin Fees	3.6	3.7	3.7	3.8	3.9
Energy Market Benefits	10.4	8.9	5.3	2.3	3.5
Capacity Market Benefits	8.4	11.8	11.8	11.8	11.8
Elimination of Depancaking	4.2	4.0	4.0	4.1	2.4
Total Variance	**26.6**	**28.4**	**24.8**	**22.0**	**22.0**

- **Admin Fees – the high-favorability case assumes 20% lower admin fees vs. the base case.**
- **Energy Market Benefits** – the high case reflects low commodity prices (see Table 3). In this case, low prices allow for the lowest increase in the cost to serve native load but still allow for a more-than-offsetting increase in market sales vs. standalone operations. The net of these impacts is the most favorable with low prices.
- **Capacity Market Benefits** – the high case reflects the highest capacity auction clearing rates observed since the 2016/2017 planning year.
- **Depancaking** – the high case assumes that 20% higher depancaking expenses can be avoided by joining an RTO by assuming an increase in MISO's drive-out rate.

10 Longer-Term Considerations

Absent RTO membership, the Companies project needing new capacity as they retire their coal fleet.[42] As the need for new capacity develops, the RTO membership evaluation becomes more complex. On a standalone basis, the Companies would need to decide what amount and type of new capacity to add to meet their optimal reserve margin range for reliability. In an RTO, the Companies would need to determine the appropriate risk profile that (1) offsets the fixed costs of RTO membership with financial benefits to customers and (2) mitigates customers' exposure to price volatility in the RTOs' energy and capacity markets. While the Companies own their existing resources, there is a natural hedge to this price risk by offsetting the costs with energy and capacity revenues in the RTO markets. But as more of the Companies' existing units retire, this hedge degrades, and exposure increases, without mitigation in some form.

At one extreme, the Companies could increasingly rely on the RTO for their net energy and capacity needs as their own generation retires. This unhedged approach would avoid

[42] These retirement assumptions are not yet firm commitments but will require further evaluation as the units continue to operate and as potential new environmental regulations develop.

the costs of new generation but would come with significant exposure to volatility in the energy and capacity markets. In periods of high energy prices (which are often correlated with periods of high load/extreme temperatures), the costs to customers could increase drastically.

A fully hedged portfolio would be similar to one under the Companies' standalone planning in which the Companies would expect to cover their own capacity and energy needs on a net basis, similar to the RTOs' fixed resource requirement option. Such a portfolio would effectively eliminate market price risk but may be more costly than a portfolio with fewer resources and some amount of market exposure.

An optimal hedging strategy could include physical assets, financial instruments, or both to mitigate price exposure. Designing the appropriate hedging strategy will require an assessment of the optimal risk exposure through a detailed evaluation of the market prices at an LMP granularity and a robust forecast of price volatility, which the Companies have not undertaken for this high-level screening analysis. For RTO membership to be favorable, the expected benefits of joining the RTO should outweigh the expected range of fixed costs consistently over time and in a clear and convincing manner because it is highly uncertain whether the Companies would be able to exit an RTO a second time. Figure 14 and Figure 15 show the projected range of fixed costs for each RTO and that by the end of the study period in 2036, the Companies would annually need to realize up to \$220 million of benefits in MISO or \$100 million in PJM for RTO membership to be favorable in the long term.[43]

[43] The main driver of the difference between MISO's and PJM's high case for net fixed costs is the assumed potential for much higher transmission costs in MISO.

Figure 14: Projected Fixed Costs Range - MISO ($M)

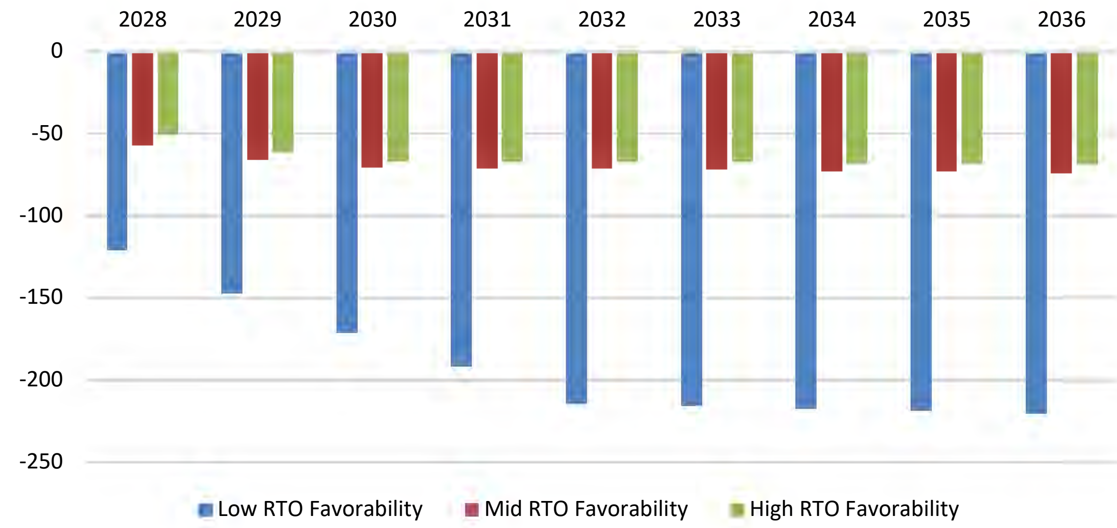
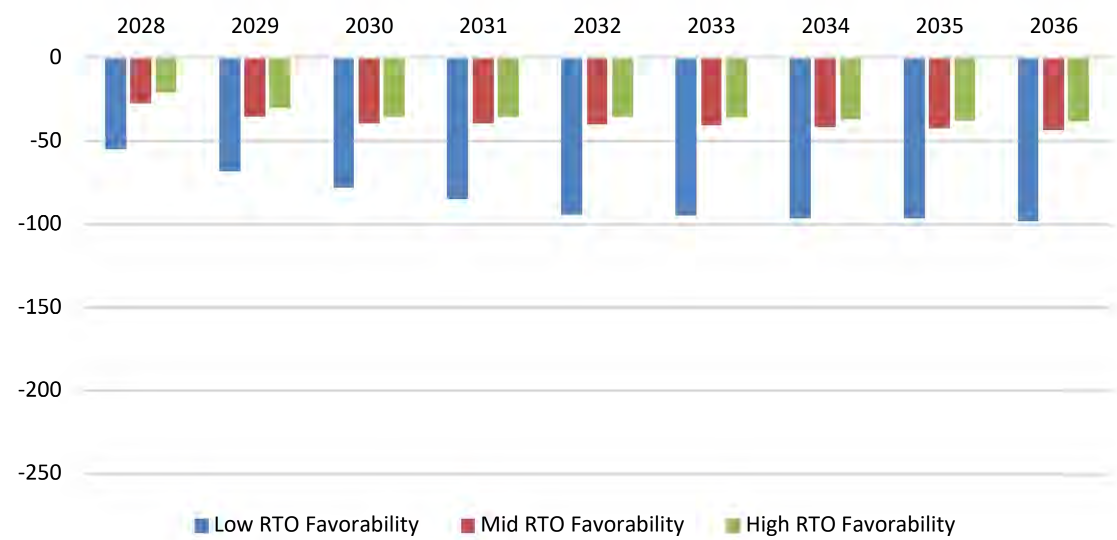


Figure 15: Projected Fixed Costs Range - PJM ($M)



11 Conclusion

The Companies do not recommend RTO membership at this time but will continue to evaluate RTO membership annually with a particular focus on the retirement timing for Mill Creek unit 2 and Brown unit 3 in 2028. This study indicates that there is likely little benefit to joining MISO prior to 2028, while joining PJM could potentially be beneficial before then if actual capacity and energy prices are high. However, when future generation retirements are assumed to occur starting in 2028, the Companies' evaluation of replacement generation would change in an RTO compared to operating on a standalone basis. Being in an RTO involves a change in mindset from having a fleet of physical generation assets to reliably serve load 8760 hours a year as a standalone utility to thinking in terms of financial risk management of both generation and load as independent activities. In an RTO, the Companies would be relying on a separate entity for managing reliability and dispatching the RTO's generation fleet to serve real-time load. At the same time, being a member of a larger generation footprint could be beneficial if the nation's and the Companies' future generation resources consist of large quantities of intermittent renewable technology because RTO membership may support higher levels of renewable penetration with lower integration costs.

12 Appendix A – Scenario Inputs

	Low Favorability Case	Mid Favorability Case	High Favorability Case
PJM			
Reliability Pricing Model (RPM)			
Base Load. All cases: Year 1 price is the historical incremental auction value to Base Residual Auction (BRA) ratio applied to the year 2 BRA value. Year 2 BRA price is median clearing price since the 2016/2017 planning year. UCAP for Ohio Falls hydroelectric and solar units reflect PJM ELCC factors. Dix Dam reflects year-round rating. MC2 assumed offline Apr-Oct each year through 2024. Base unit retirement schedule.	Low capacity clearance rates by fuel type.	Base capacity clearance rates by fuel type.	High capacity clearance by fuel type.
Energy Market Benefits – Assumed Price Forecast			
Base Load. All cases are based on Companies' electricity market price forecasts	Mid-range commodity prices.	High commodity prices.	Low commodity prices.
Transmission Expansion Costs			
	Annual expansion costs were increased from the Mid Case by compounded 14.8% per year for 10 years to reflect	Used PJM's "tcic" spreadsheet applied to forecasted load and project load-ratio share.	No change from Mid Case.

	potential large transmission grid build out to support renewable integration.		
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on 2020 state of the market reports submitted by PJM's market monitor.	Costs were reduced by 20% from the Mid Case.
Depancaking Expense			
	Increased to align with increased Transmission Expansion Cost included in Low Case	Based on current projections and assumption that only 26A would be reimbursed	Increased the Mid Case by 20% to reflect increased MISO transmission rates.
MISO			
Planning Resource Auction (PRA)			
Base Load. All auction prices reflect the median Planning Resource Auction (PRA) Zone 6 clearing price since the 2016/2017 planning year. Capacity clearance rates are based on aggregate Zone 6 figures, not fuel specific. UCAP for Ohio Falls hydroelectric reflects 42% capacity factor (as used for PJM, MISO did not specify capacity credit for intermittent hydro resources). Brown Solar UCAP reflects 38% capacity factor (as used for PJM, MISO did not specify	Low capacity clearance rates for Zone 6.	Base capacity clearance rates for Zone 6.	High capacity clearance rates in Zone 6.

capacity credit for fixed solar resources). All other Solar PPA capacity reflects MISO solar capacity credit. Dix Dam reflects year round rating. MC2 assumed offline Apr-Oct each year through 2024. Base unit retirement schedule.			
Energy Market Benefits – Assumed Price Forecast			
Base Load. All cases are based on Companies' electricity market price forecasts	Mid-range commodity prices.	High commodity prices.	Low commodity prices.
Transmission Expansion Costs			
	Annual expansion costs were increased from the Mid Case by compounded 14.8% per year for 10 years to reflect potential for large transmission build out to support renewables integration.	MISO published indicative annual charges for approved MVP applied to forecasted loads.	No change from Mid Case.
Administrative Charges			
	Costs were increased by 20% from the Mid Case.	Based on cost projections contained in MISO's 2020 revenue requirement forecast.	Costs were reduced by 20% from the Mid Case.
Depancaking Expense			
	Increased to align with increased Transmission Expansion Cost included in Low Case	Based on current projections	Increased the Mid Case by 20% to reflect increased MISO transmission rates.

13 Appendix B – Cost Analyses

The following tables show the cost and benefit components for all three favorability scenarios for each RTO. The market impacts are included for years 2023-2027, but are undetermined thereafter.

MISO Membership Cost Analysis - Low Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Admin Cost	-17.8	-18.5	-19.1	-19.8	-20.5	-21.3	-22.0	-22.9	-23.7	-24.7	-25.6	-26.6	-27.7	-28.9
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-60.8	-69.0	-77.8	-87.9	-99.4	-112.8	-127.5	-144.4	-163.7	-186.1	-186.1	-186.1	-186.1	-186.1
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-89.8	**-98.7**	**-108.1**	**-118.6**	**-131.0**	**-145.1**	**-160.6**	**-178.5**	**-198.9**	**-222.3**	**-223.3**	**-225.1**	**-226.0**	**-227.7**

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO Energy Market Benefits/(Costs)	6.5	7.5	8.6	8.6	9.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.0	1.1	1.2	1.3	1.3	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.6	24.7	25.1	26.3	16.4	17.3	6.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	38.7	**39.9**	**41.7**	**43.0**	**34.5**	**24.3**	**13.8**	**7.6**	**7.8**	**7.8**	**7.8**	**7.8**	**7.9**	**7.9**

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Net Benefits/(Costs)	**-51.1**	**-58.7**	**-66.4**	**-75.6**	**-96.4**	**-120.8**	**-146.8**	**-170.8**	**-191.2**	**-214.5**	**-215.5**	**-217.3**	**-218.1**	**-219.8**

MISO Membership Cost Analysis - Mid Case ($M)

Costs	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Admin Cost	-14.8	-15.4	-15.9	-16.5	-17.1	-17.7	-18.4	-19.0	-19.8	-20.6	-21.4	-22.2	-23.1	-24.1
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-79.0	**-79.0**	**-78.5**	**-78.1**	**-78.0**	**-78.0**	**-77.9**	**-78.2**	**-78.5**	**-78.9**	**-79.1**	**-80.2**	**-80.4**	**-81.5**

Benefits	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Energy Market Benefits/(Costs)	11.8	11.7	13.5	15.6	15.4	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.2	1.3	1.3	1.4	1.5	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	24.1	23.6	23.4	23.8	14.1	14.4	5.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	43.7	**43.2**	**45.0**	**47.6**	**38.0**	**21.4**	**12.3**	**7.6**	**7.8**	**7.8**	**7.8**	**7.8**	**7.9**	**7.9**

Net Benefits/(Costs)	**-35.3**	**-35.7**	**-33.5**	**-30.5**	**-40.0**	**-56.6**	**-65.6**	**-70.5**	**-70.8**	**-71.1**	**-71.3**	**-72.3**	**-72.5**	**-73.7**

MISO Membership Cost Analysis - High Case ($M)

Costs	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Admin Cost	-11.9	-12.3	-12.7	-13.2	-13.7	-14.2	-14.7	-15.2	-15.8	-16.5	-17.1	-17.8	-18.5	-19.3
MISO Uplift Cost - Revenue Neutrality Uplift	-7.7	-7.7	-7.6	-7.6	-7.6	-7.6	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5	-7.5
MISO Transmission Expansion Cost (MVP)	-53.0	-52.3	-51.4	-50.6	-49.9	-49.3	-48.5	-47.9	-47.3	-46.8	-46.2	-45.6	-45.1	-44.8
LG&E/KU Internal Staffing & Implementation	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost XM Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-76.0	**-75.9**	**-75.3**	**-74.8**	**-74.6**	**-74.5**	**-74.3**	**-74.4**	**-74.6**	**-74.8**	**-74.8**	**-75.7**	**-75.7**	**-76.7**

Benefits	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
MISO Energy Market Benefits/(Costs)	20.7	20.0	18.5	15.2	16.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
MISO Capacity Market Benefits/(Costs)	1.3	1.3	1.4	1.5	1.6	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
LG&E/KU Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	28.9	28.3	28.1	28.6	17.0	17.3	6.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	57.4	**56.2**	**54.7**	**52.1**	**42.4**	**24.3**	**13.3**	**7.7**	**7.8**	**7.9**	**7.9**	**7.9**	**7.9**	**8.0**

Net Benefits/(Costs)	**-18.6**	**-19.6**	**-20.6**	**-22.7**	**-32.2**	**-50.2**	**-60.9**	**-66.6**	**-66.7**	**-66.9**	**-66.9**	**-67.8**	**-67.8**	**-68.8**

PJM Membership Cost Analysis - Low Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-21.6	-22.1	-22.5	-22.9	-23.4	-24.0	-24.4	-25.0	-25.6	-26.3	-26.8	-27.5	-28.2	-29.0
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-22.3	-25.3	-28.4	-33.0	-37.0	-41.4	-46.4	-51.9	-58.0	-66.6	-66.6	-66.6	-66.6	-66.6
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-52.8	-55.7	-59.2	-64.1	-68.6	-73.5	-79.1	-85.3	-92.3	-101.5	-102.2	-103.7	-104.1	-105.4

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	7.0	8.2	8.8	8.6	10.1	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	-4.8	-6.4	-6.7	-6.0	-4.9	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	20.9	20.1	20.0	20.4	11.9	12.2	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	29.7	28.6	28.8	29.9	24.0	19.2	11.4	7.6	7.8	7.8	7.8	7.8	7.9	7.9

Net Benefits/(Costs)	**-23.2**	**-27.1**	**-30.4**	**-34.2**	**-44.6**	**-54.3**	**-67.7**	**-77.7**	**-84.5**	**-93.7**	**-94.4**	**-95.8**	**-96.3**	**-97.6**

PJM Membership Cost Analysis - Mid Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-18.0	-18.4	-18.7	-19.1	-19.5	-20.0	-20.4	-20.8	-21.3	-21.9	-22.4	-22.9	-23.5	-24.2
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-19.4	-19.2	-18.8	-19.0	-18.5	-18.1	-17.7	-17.2	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-46.4	-45.9	-45.8	-46.2	-46.3	-46.2	-46.2	-46.5	-46.7	-47.3	-47.9	-49.2	-49.5	-50.7

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	10.5	12.1	12.6	13.9	14.0	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	4.2	6.7	6.9	7.5	8.6	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	20.9	20.1	20.0	20.4	11.9	12.2	4.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	42.2	45.6	46.2	48.7	41.5	19.2	11.4	7.6	7.8	7.8	7.8	7.8	7.9	7.9

Net Benefits/(Costs)	**-4.2**	**-0.3**	**0.4**	**2.5**	**-4.8**	**-27.0**	**-34.9**	**-38.8**	**-38.9**	**-39.5**	**-40.1**	**-41.4**	**-41.7**	**-42.9**

PJM Membership Cost Analysis - High Case ($M)

Costs	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Admin Fee Cost	-14.4	-14.7	-15.0	-15.3	-15.6	-16.0	-16.3	-16.7	-17.1	-17.5	-17.9	-18.3	-18.8	-19.3
PJM Energy Uplift (BOR) Cost	-4.8	-4.8	-4.8	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
PJM Transmission Expansion Cost	-19.4	-19.2	-18.8	-19.0	-18.5	-18.1	-17.7	-17.2	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
LG&E/KU Internal Staffing & Implementation	-1.5	-0.8	-0.7	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
LG&E/KU Lost Transmission Revenue	-1.3	-1.3	-1.3	-1.2	-1.2	-1.2	-1.2	-1.5	-1.6	-1.6	-1.7	-2.5	-2.2	-2.7
LG&E/KU Lost Joint Party Settlement Revenue	-1.4	-1.5	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9
	-42.8	-42.2	-42.1	-42.4	-42.4	-42.2	-42.2	-42.3	-42.5	-42.9	-43.4	-44.6	-44.9	-45.9

Benefits	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PJM Energy Market Beneits/(Costs)	20.9	21.0	17.8	16.3	17.5	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
PJM Capacity Market Benefits/(Costs)	12.6	18.5	18.8	19.3	20.4	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*	*TBD*
Avoided Fees (FERC, TVA RC, ITO, TEE)	6.6	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4	7.4	7.4	7.4	7.5	7.5
LKE Elimination of De-Pancaking	25.1	24.2	24.0	24.5	14.3	14.6	5.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	65.2	70.3	67.3	67.0	59.1	21.6	12.2	7.7	7.8	7.9	7.9	7.9	7.9	8.0

Net Benefits/(Costs)	**22.4**	**28.1**	**25.3**	**24.5**	**16.8**	**-20.6**	**-29.9**	**-34.6**	**-34.6**	**-35.0**	**-35.5**	**-36.7**	**-36.9**	**-38.0**

14 Appendix C – Energy Market Benefits

The tables below show the projected incremental total energy market benefits to market sales revenues and costs to native load through 2027 of joining MISO and PJM compared to the Companies' current business plan across the low/mid/high commodity price forecast scenarios for each RTO. Negative figures reflect net benefits; positive figures reflect net costs.

MISO - Mid Load ($M)		2023	2024	2025	2026	2027
	Market Energy Sales	-151	-148	-148	-141	-138
	Native Load Cost	130	129	130	126	121
Low Commodity Prices	Total	-21	-20	-18	-15	-17
	Market Energy Sales	-243	-242	-231	-208	-188
	Native Load Cost	236	234	222	199	178
Mid Commodity Prices	Total	-7	-8	-9	-9	-10
	Market Energy Sales	-229	-239	-233	-210	-204
	Native Load Cost	217	227	219	195	189
High Commodity Prices	Total	-12	-12	-14	-16	-15

PJM - Mid Load ($M)		2023	2024	2025	2026	2027
	Market Energy Sales	-128	-138	-147	-153	-159
	Native Load Cost	107	117	129	136	142
Low Commodity Prices	Total	-21	-21	-18	-16	-18
	Market Energy Sales	-186	-202	-207	-201	-199
	Native Load Cost	179	194	199	192	189
Mid Commodity Prices	Total	-7	-8	-9	-9	-10
	Market Energy Sales	-248	-269	-269	-253	-254
	Native Load Cost	237	257	256	239	240
High Commodity Prices	Total	-10	-12	-13	-14	-14

15 Appendix D – Non-Quantifiable Considerations

Consideration	Stability	Description
Governance		
Stakeholder Process – Tariff Filings and Operating Decisions	Continues to Evolve and Change	Although the structures of the two RTOs differ, both RTOs have defined rules with respect to regulatory filing rights. This means that certain stakeholders have considerably more power than others to push RTO policy and RTO requirements.
Stakeholder Mix – Weighted Voting Rights	Continues to Evolve and Change	MISO has approximately 189 voting entities (of which 146 are members) in ten different stakeholder sectors with weighted voting rights, including but not limited to sectors for Transmission Owners, Marketers, Public Consumer Advocates, Environmental and other groups, and Transmission Developers. PJM has approximately 133 voting members in five different sectors for transmission owners, generation owners, retail end-use customers, electric distributors, and suppliers who do not qualify for any of the other four sectors.[44]
Policy Impact	Stable	The RTOs have demonstrated considerable impact on the creation and implementation of federal energy, environmental, and market policy. Whether or not the RTO position aligns with the interests of the Companies and their customers would determine whether an RTO will be an effective advocate or a complicating hurdle in managing an evolving federal regulatory landscape. Given the diversity among stakeholders and their and the RTO's own interests, alignment cannot be assumed.
FERC Oversight of Tariff and Markets	Continues to Evolve and Change	Although FERC review of RTO tariff filings is subject to the statutory authorities conveyed in the Federal Power Act, the implementation of this statutory authority to further federal policy objectives continues to evolve. The PJM and MISO tariffs, including the market rules and requirements, are complex, and some of the most significant changes in

[44] Because of the size of the Companies, it is unlikely that the Companies would fall into the small group of stakeholders able to essentially unilaterally move or strongly influence RTO policy. Therefore, simply joining an RTO would eliminate a significant amount of the control that the Companies have to manage costs and operations to the benefit of their customers.

		RTO tariffs are often driven by FERC initiative and mandate rather than stakeholder proposals.[45]
Markets		
Market Structure	Continues to Evolve and Change	Market structure and market prices administered by RTOs are subject to change over time from various drivers, including FERC-directed market changes (which can include such things as changes to market compensation structures, performance requirements, and participant responsibilities), stakeholder initiatives, independent market monitor recommendations, or actions from the RTOs themselves.[46] The PJM MOPR dispute, the MISO's strategic initiatives as documented in the MISO Forward report and integrated roadmap, and the efforts of both RTOs to integrated energy storage technology and develop new reserve products are illustrative of this continuing evolution.
Default of Other Market Participants	Unpredictable	See Section 3.2
Misconduct of Other Market Participants	Unpredictable	Entities' market activities designed to suppress or inflate market prices can directly impact other market participants' opportunities and market performance. Although there are processes at FERC to disgorge amounts if there is a finding of unlawful manipulation, recovery of disgorged profits is not guaranteed and takes significant time.[47]

[45] For example, in February 2018, PJM presented two alternatives for a rule change to FERC and requested the Commission determine between these alternatives the appropriate approach since PJM, its market monitor, and its stakeholder committee members were unable to agree. FERC rejected both proposals in June 2018 and recommended PJM pursue a third alternative.

[46] *See, e.g.,* FERC's notice convening technical conferences, titled *Modernizing Electricity Market Design*, in FERC Docket No. AD21-10. The technical conferences are intended to discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time.

[47] *See e.g.*, *Virginia Electric & Power Company, d/b/a Dominion Energy Virginia (DEV)*, Docket No. IN19-3-000, Order Approving Stipulation and Consent Agreement, 167 FERC ¶61,103 (2019), in which DEV was assessed a civil penalty of $7 million and required to disgorge $7 million in profits due to the FERC's finding that DEV had violated market manipulation prohibitions by allegedly improperly targeting and increasing its receipt of lost opportunity cost credits; *PSEG Energy Resources & Trade, LLC*, Docket No. IN18-4-000, Order Approving Stipulation and Consent Agreement, 163 FERC ¶61,022 (2018), in which PSEG was assessed a civil penalty of $8 million and required to disgorge approximately $27 million in profits and $4.5 million in interest due to the FERC's finding that PSEG had violated market manipulation prohibitions by allegedly submitting incorrect cost-based offers into the PJM market.

Market Maturity	Continues to Evolve and Change	With the recent MOPR order, the future of PJM's RPM is uncertain. The MISO PRA underwent reforms to create External Resource Zones to allocate excess auction revenues to Load Serving Entities impacted by changes to MISO's resource adequacy construct through Historic Unit Considerations, and align parameters used to calculate auction inputs such as import and export limits and Local Clearing Requirements with the use of these limits in the PRA.[48] In addition, the MISO Forward report and integrated roadmap include several market reform initiatives to accommodate the changing composition of MISO's market.
Market Efficiency	Continues to Evolve and Change	PJM issued a Problem Statement in 2017 identifying a concern that the current Locational Marginal Prices ("LMP") do not accurately represent the true incremental cost of generation or send the right price signals. Over the course of 2018 PJM developed a proposal to address this concern[49] resulting in a tariff filing with the FERC in March of 2019.[50] FERC has yet to issue an order on the filing. One of the key areas of focus identified by MISO in 2019 was the Resource Adequacy and Need initiative, to identify near-term solutions to increase the conversion of committed capacity resources into energy during times of need.[51]
Future Costs and Cost Allocation		
Cost Allocation	Continues to Evolve and Change	Cost allocation methods are periodically revisited and can potentially change in the future. An individual RTO member has little control over cost-related decisions and challenges to those decisions can be lengthy and unproductive.[52]
Transmission Expansion Costs	Continues to Evolve and Change	RTOs have seen consistent growth in transmission projects and development. In RTOs, determinations as to whether projects are built

[48] *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER18-1173-000 and ER18-1173-001, 164 FERC ¶ 61,081 (2018).

[49] Price Formation: Energy Price Formation Senior Task Force, PJM Interconnection, December 14, 2018, https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20181214/20181214-item-04-price-formation-paper.ashx

[50] *PJM Interconnection, L.L.C.*, Docket No. EL19-58.

[51] https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

[52] For example, *see supra* fn 15 describing the Linden VFT, LLC RTEP project cost dispute with PJM. See also Section 7.1.1 above, in particular footnote 14, regarding evolving cost allocation discussions in MISO for transmission expansion projects identified in its Long-Range Transmission Plan (LRTP) process.

		and who bears the costs associated with the projects are subject to still-evolving RTO rules.[53] In addition, federal and state policy on transmission expansion and cost allocation continues to evolve and is uncertain.[54] In both RTOs, load is typically assigned some, if not most or all, of the costs associated with transmission expansion. Factors that trigger the need for projects, how those projects are designated, who is awarded the option to build, and the percentage of expansion cost assigned locally rather than across the RTO footprint is governed by the RTO's tariff and transmission planning processes. Individual transmission owners within an RTO have limited power to control these costs.[55] However, the Companies will be required to comply with the results of the ANOPR proceeding at FERC regardless of whether they are in an RTO or not, thus there is presently considerable uncertainty in the industry generally regarding transmission planning and cost allocation.
Planning and Operational Control		
Functional Control of Generation Assets	Stable	RTO integration requires the Companies to transfer functional control of their transmission system to an RTO in addition to committing the Companies' generation assets and load to participation in the RTO administered markets. The transfer of control and commitment of generation means that the RTO makes both planning and operating decisions for the Companies' assets that affect reliability, asset performance and longevity, and costs borne by load. This extends to the

[53] MISO changed aspects of its transmission cost allocation in 2003, 2007, 2009, and 2012, and recently started another stakeholder project to review cost allocation. In 2018, PJM changed the cost allocation for certain regional and lower voltage facilities included in RTEP to provide that one half of the costs of these facilities would be allocated on a load-ratio share basis and the other half of the costs allocated based on the solution-based distribution factor (DFAX) method. *PJM Interconnection, L.L.C.*, Docket Nos. ER18-579-000 and ER18-579-001.

[54] *See, e.g.,* FERC's issuance of an Advance Notice of Proposed Rulemaking, titled *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, in FERC Docket No. RM21-17-000 (July 15, 2021) (the "ANOPR").

[55] *See, e.g.,* FERC's approval of the PJM filing associated with the assignment of cost responsibility for 39 baseline upgrades from the 2017 Regional Transmission Expansion Plan, rejecting a challenge to the allocation of several projects by Old Dominion Electric Cooperative who had argued that PJM provided an inadequate basis for the allocation. FERC approved PJM's use of a proxy in assigning the costs entirely to the local zone. *PJM Interconnection, LLC*, 161 FERC ¶ 61,190 (2017).

		approval of outages and maintenance, determinations impacting fuel supply and fuel supply arrangements, and dispatch decisions.
Drivers Behind Generation Dispatch Decisions	Unpredictable	See Section 3.2.
Transmission Planning	Continues to Evolve and Change	Transmission Owners and Transmission Planners in an RTO are subject to the RTO's transmission planning criteria. Although some limited authority remains with the Transmission Owners and Transmission Planners, the RTO would be the Planning Authority for the region and planning studies would need to conform to the RTO's criteria. Transmission Owners who integrate into an RTO assume an obligation to build in accordance with the applicable RTO's tariff and agreements.
Other/Optional Upgrades	Continues to Evolve and Change	In RTOs, market participants and transmission developers are able to propose and build transmission projects that do not otherwise pass transmission-planning criteria in order to obtain Financial Transmission Rights.
Right of First Refusal	Continues to Evolve and Change	FERC directed transmission providers to eliminate provisions in FERC jurisdictional tariffs and agreements that granted incumbent Transmission Owners a right of first refusal to transmission facilities in their respective service territories or have a right to build regional transmission projects when the costs of those projects would be assigned to the incumbent's load.
Resource Adequacy	Continues to Evolve and Change	The PJM states are deregulated, with the RTO setting resource adequacy requirements and procuring capacity through auction to meet projected need. MISO states, on the other hand, have typically been regulated, with state commissions setting resource adequacy. Both PJM and MISO have fixed resource plans that allow a load serving entity to demonstrate that it has designated capacity to meet all or a portion of its load and reserve requirements.
Regional Operations	Stable	RTOs are able to leverage resources and redispatch options across a broad region, which may provide efficiencies and flexibility in mitigating operating issues and resource optionality.

Regional Coordination	Stable	Integrated operations across the different Transmission Owner systems within the RTO region is well established and centralized operations and formal dispute processes have eliminated many of the coordination issues between systems within the RTO.
Interregional Coordination	Continues to Evolve and Change	Interregional coordination between the RTOs and neighboring external systems is structured but also subject to frequent litigation and change. Issues along the RTO seams, both between markets and between markets and non-RTO areas, remain problematic, and any integration that may change or impact an existing seam is likely to pose additional issues that would require resolution.
Competitive Transmission	Continues to Evolve and Change	Development of transmission for which the costs are regionally allocated is a competitive process in RTOs, although little results have been seen by way of competitive transmission projects in RTOs to date. The types of transmission projects subject to competitive bidding requirements in the RTOs continues to evolve. In 2019, FERC instituted a proceeding to require PJM to include projects needed to meet local transmission planning criteria in the competitive bidding process.[56]

[56] *PJM Interconnection, L.L.C.*, Docket No. EL19-61-000, 168 FERC ¶ 61,132 (2019).

Compliance		
Compliance Program Costs	Continues to Evolve and Change	An analysis of the NERC Compliance impact of RTO membership found the impact to be cost-neutral, with a slight potential that it could actually increase compliance costs. Although responsibility for compliance with some standards and requirements is transferred to the RTO, the member companies retain responsibility for most compliance, and may still be required to provide evidence of compliance with standards for which the RTO is responsible.
Audits	Stable	Membership in an RTO does not alleviate any of the burden and expenses related to periodic audits. Member companies would still be subject to periodic regulatory audits by the regional entity and may also be subject to additional audits by the RTO to ensure compliance with standards and RTO-specific manuals or processes.
Fines and Penalties	Unpredictable	For any fines and penalties that result from the failure of a member to comply with a standard or requirement, the cost of the fine is allocated back to that member. For any fines or penalties assessed based on the RTO's failure to comply, the cost of the penalty is allocated to all member companies. For any violations where the RTO assigned responsibility for the standard or requirement, or there is joint responsibility between the RTO and the member company, the RTO retains all control over decisions to self-report and negotiate penalties.
Exit Fees		
Costs to Exit	Stable	MISO's and PJM's transmission owner agreements provide a mechanism for a transmission-owning member of either RTO to withdraw from the RTO. The notice period and requirements of such withdrawals vary with the RTOs, but both contain language that the withdrawing member shall remain liable for obligations undertaken while under the respective RTO agreement.[57]

[57] As the Companies experienced with its MISO withdrawal in 2006, exiting an RTO can be complex and time consuming, and may result in a significant level of financial obligation.

EXHIBIT ACL-3

Public Company Responses to Data Requests

Data Requests

LG&E-KU Response to Commission Staff Request 1-53(f)
LG&E-KU Response to Commission Staff Request 5-4(a)

LG&E-KU Response to Sierra Club Request 2-18
LG&E-KU Response to Sierra Club Request 2-26(b), Attachment 1
LG&E-KU Response to Sierra Club Request 2-30

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Request for Information
Dated February 17, 2023

Case No. 2022-00402

Question No. 53

Responding Witness: David S. Sinclair / Stuart A. Wilson

Q-53. Refer to the Wilson Direct Testimony, Exhibit SAW-1, page 5, subpart 3, and Table 1, page 11.

a. Explain how and whether the analysis of reliability enhancements was more qualitative in nature based on experience and personal knowledge or quantitative based on modeling results.

b. Explain how the cost of the Brown Energy Storage System (Brown BESS) compares to the costs of the 2-hour and 4-hour batteries submitted in response to the RFP.

c. Assuming that the Brown BESS will be utilized in the same manner as the combination solar/battery projects submitted in response to the RFP, explain how the cost of the Brown BESS utilized in conjunction with LG&E/KU's proposed solar projects compares to the combination battery/solar projects submitted in response to the RFP.

d. From a ratepayer's perspective, explain why it is more economical for LG&E/KU to own Brown BESS as opposed to accepting one of the RFP proposals.

e. Step 2 involved stress testing the economically optimal portfolio. Step 3 involved analyzing the addition of additional resources to the economically optimal portfolio. Explain and compare the portfolio cost differences between the economically optimal portfolio (Step 2) and the final portfolio (Step 3).

f. Provide a table showing the annual load forecast components and the annual existing resources, resource additions and retirements, net capacity position and reserve margin over the forecast period for both summer and winter seasons.

A-53.

a. The reliability analysis was quantitative based on modeling results. See section 4.6 of the Exhibit SAW-1 beginning on page 34. Please note that this section of Exhibit SAW-1 was updated in the response to Question No. 47(a).

b. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The attachment compares the cost of Brown BESS to the costs of the 2-hour and 4-hour battery proposals based on the projects' levelized costs. The cost of Brown BESS reflects the updates to ITC revenue requirement calculations discussed in the response to Question No. 47(a). The levelized cost of the other 4-hour battery proposals ranges from \$100,898/MW-Year to \$206,332/MW-Year and averages \$153,012/MW-Year. The levelized cost of the Brown BESS is \$138,133/MW-Year.

   In the Stage One, Step One analysis (Portfolio Development and Screening with PLEXOS), PLEXOS did not select battery storage as part of a least-cost portfolio in any of the fuel-price cases. Brown BESS is included to enhance reliability, but its primary value is in providing operational experience for integrating future renewable generation. It is not the most cost-effective means of enhancing reliability as modeled. See section 4.6.2 of the updated Exhibit SAW-1 beginning on page 36. See also the response to Question Nos. 25(b) and 25(c).

c. The Companies' BESS is not linked to, or limited to, the operation of solar. It will be connected to the transmission grid and will be directly charged with energy from the grid and will discharge energy into the grid independent of the operation of any solar projects on the system. See the response to part (b).

d. See Sinclair Direct Testimony at pages 25-26. The financial development and contractual risks of solar PPAs apply to BESS PPAs, and the industry's understanding of BESS as a means of improving reliability continues to develop. It is therefore unclear whether a BESS PPA would be more economical than the Brown BESS, but it would certainly involve additional risks and provide the Companies significantly less valuable operational experience with a technology that is likely to become increasingly important as renewable energy capacity grows.

e. Cost differences between the final portfolio (Step 3) and the economically optimal portfolio (Step 2) are due to the costs related to the Marion and Mercer solar assets and Brown BESS. The table below shows the incremental PVRR of each of these components in the fuel price scenarios with zero CO_2 price and zero REC price. As requested, the PVRR differences are computed with the assumption that the solar PPA projects in the economically optimal portfolio will be completed. These values reflect the updated PTC and ITC revenue requirement calculations described in the response to Question No. 47(a).

PVRR Comparison (Final Portfolio less Economically Optimal Portfolio, $M, 2022 dollars, Zero CO_2 Prices, Zero REC Prices*)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR Impact of Solar Assets	PVRR Impact of Brown BESS	Total PVRR Impact
Expected CTG	Low Gas, Mid CTG	253	130	384
	Mid Gas, Mid CTG	196	127	323
	High Gas, Mid CTG	35	95	131
Atypical CTG	Low Gas, High CTG	245	130	375
	High Gas, Low CTG	38	78	116
	High Gas, Curr CTG	-49	79	29

*Over the last three years, the Companies have sold Brown Solar RECs for between $8 and $13 per REC. A price of $10 per REC reduces the solar assets' PVRR impact by $72 million. Non-zero CO_2 prices would also improve the solar assets' economics.

f. See attached.

Summer Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Peak Load	**6,162**	**6,197**	**6,248**	**6,253**	**6,347**	**6,319**	**6,308**	**6,305**	**6,302**	**6,298**	**6,293**	**6,289**	**6,284**	**6,280**	**6,275**	**6,271**	**6,266**	**6,262**	**6,257**	**6,253**	**6,249**	**6,244**	**6,240**	**6,235**	**6,231**	**6,226**	**6,222**	**6,218**
Dispatchable Generation Resources																												
Existing Resources	7,583	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612
Retirements/Additions																												
Coal[1]	-300	-300	-300	-300	-597	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,494	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646	-1,646
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs[2]	0	0	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC[3]	0	0	0	0	621	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242	1,242
Total	7,283	7,312	7,265	7,265	7,589	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,313	7,161	7,161	7,161	7,161	7,161	7,161	7,161	7,161	7,161	7,161	7,161
Reserve Margin %	18.2%	18.0%	16.3%	16.2%	19.6%	15.7%	15.9%	16.0%	16.0%	16.1%	16.2%	16.3%	16.4%	16.5%	16.5%	16.6%	16.7%	14.4%	14.4%	14.5%	14.6%	14.7%	14.8%	14.8%	14.9%	15.0%	15.1%	15.2%
Intermittent/Limited-Duration Resources																												
Existing Resources	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Existing CSR	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128
Existing Dispatchable DSM[4]	62	60	56	52	49	46	44	42	40	38	36	35	33	32	31	30	29	28	28	27	27	26	26	25	25	25	24	24
Retirements/Additions																												
Solar[5]	0	79	177	681	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866	866
Battery Storage	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Dispatchable DSM[4]	0	14	28	44	70	102	121	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Total	294	385	493	1,136	1,343	1,373	1,389	1,393	1,391	1,389	1,388	1,386	1,385	1,384	1,383	1,382	1,381	1,380	1,379	1,379	1,378	1,378	1,377	1,377	1,376	1,376	1,376	1,376
Total Supply	**7,577**	**7,697**	**7,758**	**8,401**	**8,932**	**8,686**	**8,702**	**8,706**	**8,704**	**8,702**	**8,701**	**8,699**	**8,698**	**8,697**	**8,695**	**8,695**	**8,694**	**8,541**	**8,540**	**8,540**	**8,539**	**8,538**	**8,538**	**8,538**	**8,537**	**8,537**	**8,537**	**8,536**
Total Reserve Margin	**1,415**	**1,500**	**1,510**	**2,148**	**2,585**	**2,366**	**2,394**	**2,401**	**2,402**	**2,405**	**2,407**	**2,410**	**2,414**	**2,417**	**2,420**	**2,424**	**2,427**	**2,279**	**2,283**	**2,287**	**2,290**	**2,294**	**2,298**	**2,302**	**2,306**	**2,311**	**2,315**	**2,319**
Total Reserve Margin %	**23.0%**	**24.2%**	**24.2%**	**34.3%**	**40.7%**	**37.4%**	**38.0%**	**38.1%**	**38.1%**	**38.2%**	**38.3%**	**38.3%**	**38.4%**	**38.5%**	**38.6%**	**38.7%**	**38.7%**	**36.4%**	**36.5%**	**36.6%**	**36.7%**	**36.7%**	**36.8%**	**36.9%**	**37.0%**	**37.1%**	**37.2%**	**37.3%**

Winter Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Peak Load	**5,910**	**5,908**	**6,011**	**6,003**	**6,107**	**6,104**	**6,103**	**6,102**	**6,100**	**6,101**	**6,103**	**6,104**	**6,106**	**6,107**	**6,108**	**6,110**	**6,111**	**6,113**	**6,114**	**6,116**	**6,117**	**6,118**	**6,120**	**6,121**	**6,123**	**6,124**	**6,125**	**6,127**
Dispatchable Generation Resources																												
Existing Resources	7,901	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909
Retirements/Additions																												
Coal[1]	0	0	-300	-300	-597	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,499	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657	-1,657
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs[2]	0	0	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC[3]	0	0	0	0	641	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282	1,282
Total	7,901	7,909	7,554	7,554	7,898	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,637	7,479	7,479	7,479	7,479	7,479	7,479	7,479	7,479	7,479	7,479	7,479
Reserve Margin %	33.7%	33.9%	25.7%	25.8%	29.3%	25.1%	25.1%	25.2%	25.2%	25.2%	25.1%	25.1%	25.1%	25.0%	25.0%	25.0%	25.0%	22.3%	22.3%	22.3%	22.3%	22.2%	22.2%	22.2%	22.1%	22.1%	22.1%	22.1%
Intermittent/Limited-Duration Resources																												
Existing Resources	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Existing CSR	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128
Existing Dispatchable DSM[4]	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Retirements/Additions																												
Solar[5]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battery Storage	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Dispatchable DSM[4]	0	13	26	40	61	89	103	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Total	221	234	246	385	407	435	449	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Total Supply	**8,122**	**8,143**	**7,800**	**7,939**	**8,305**	**8,072**	**8,085**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**8,087**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**	**7,929**
Total Reserve Margin	**2,211**	**2,235**	**1,789**	**1,936**	**2,197**	**1,967**	**1,982**	**1,985**	**1,987**	**1,985**	**1,984**	**1,982**	**1,981**	**1,980**	**1,978**	**1,977**	**1,975**	**1,816**	**1,815**	**1,813**	**1,812**	**1,810**	**1,809**	**1,807**	**1,806**	**1,805**	**1,803**	**1,802**
Total Reserve Margin %	**37.4%**	**37.8%**	**29.8%**	**32.2%**	**36.0%**	**32.2%**	**32.5%**	**32.5%**	**32.6%**	**32.5%**	**32.5%**	**32.5%**	**32.4%**	**32.4%**	**32.4%**	**32.4%**	**32.3%**	**29.7%**	**29.7%**	**29.6%**	**29.6%**	**29.6%**	**29.6%**	**29.5%**	**29.5%**	**29.5%**	**29.4%**	**29.4%**

[1]Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NO_x limits, which results in a reduction of available summer capacity through 2024. Mill Creek 1 will be retired by the end of 2024, Mill Creek 2 is retired in 2027, Ghent 2 and Brown 3 are retired in 2028, and OVEC's contract term ends in 2040.

[2]Haefling 1-2 and Paddy's Run 12 are assumed to be retired in 2025.

[3]Mill Creek 5 and Brown 12 are added in 2027 and 2028, respectively.

[4]Dispatchable DSM reflects expected load reductions under normal peak weather conditions.

[5]100 MW of solar capacity is added in 2024 (Rhudes Creek PPA), 125 MW in 2025 (Ragland PPA), 642 MW in 2026 (Gray's Branch PPA, Nacke Pike PPA, Mercer County Solar Facility, and Song Sparrow PPA), and 235 MW in 2027 (Gage Solar PPA and Marion County Solar Facility).
Capacity values reflect 78.6% expected contribution to summer peak capacity and 0% expected contribution to winter peak capacity.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Fifth Request for Information
Dated June 27, 2023

Case No. 2022-00402

Question No. 4

Responding Witness: Stuart A. Wilson

Q-4. Refer to LG&E/KU's response to Staff's First Request for Information (Staff's First Request), Item 47(a), Exhibit SAW-1, Appendix D, pages D-22 through D-24.

a. Explain whether the results of the economic minimum reserve margin analysis (17 percent summer and 24 percent winter) correspond to a LOLE of 3.87 days in 10 years.

b. Using the resources LG&E/KU used to calculate the economic reserve margin, explain what the minimum reserve margin and resource portfolio would correspond to a LOLE 1 day in 10 years.

c. Explain why a LOLE of 1 day in 10 years is not appropriate for determining the minimum reserve margin target.

A-4.

a. They do not. As noted on page 13 of Exhibit SB4-1, an LOLE of 3.87 days in 10 years corresponds to a portfolio with a similar composition of resources (i.e., similar proportions of fully dispatchable, intermittent, and limited duration resources) but with slightly higher reserve margins (17.9% summer, 26.0% winter). A portfolio with (1) a similar resource composition and (2) 17% summer and 24% winter reserve margins would have a somewhat higher LOLE.

b. As discussed in Appendix D of Exhibit SAW-1, page D-22, the Companies calculated their economic reserve margins based on their existing portfolio except Mill Creek 1 (planned retirement in 2024) and the small-frame SCCTs (assumed retirement in 2025). In addition, the analysis, which was completed for 2028, assumed the Rhudes Creek and Ragland solar PPAs are not completed. Consistent with the methodology used to calculate the maximums of the Companies' summer and winter reserve margin ranges for the 2021

IRP, the Companies evaluated adding SCCT capacity to this portfolio to achieve an LOLE of 1 day in 10 years. Achieving an LOLE of 1 day in 10 years requires 240 MW of SCCT capacity and the associated reserve margins are 23% in the summer and 31% in the winter.

For the workpapers supporting this response, see the attachments being provided as separate files in Excel format as well as the SERVM database file named "SERVM.D20230703.T084051.Daily.BAK," which is included in the confidential attachment to Question No. 1(b) at the filepath: \CONFIDENTIAL_WORKPAPERS\SERVM_PSC5_01\SERVM.zip.

c. The Companies have not said that an LOLE of 1 day in 10 years is inappropriate for determining the minimum reserve margin target. LOLE gives no consideration to the cost of unserved energy. Therefore, the Companies also consider the economic reserve margin, which minimizes the sum of (1) generation capacity costs and (2) reliability and generation production costs.[35] Either method could produce lower minimum reserve margins depending on the input assumptions.

[35] See Appendix D to Exhibit SAW-1, page D-8.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Sierra Club's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 2-18

Responding Witness: David S. Sinclair

Q.2-18. Please refer to "2022 RTO Membership Analysis," Exhibit 2 "Guidehouse Energy Markets Analysis," at pages 3-35. For the referenced capacity expansion assessment:

a. Please confirm that Guidehouse used Power System Optimizer to perform the capacity expansion assessment. If not confirmed, please provide the name of the software used to perform the capacity expansion assessment. If the tool is proprietary, please explain the method it uses.

b. Please provide all input and output files supporting the capacity expansion assessment (in electronic, machine readable format with formulae intact).

c. Please describe any methods and assumptions used in the capacity expansion model to adjust costs and benefits that occur in different years in order to optimize net benefits, such as calculations of present value, annualization or levelizing of capital costs, capital recovery factors, etc. Among the assumptions provided, please include the discount rate, whether the discount rate used reflects real vs. nominal, assumed useful life or depreciation schedule of capital investments if applicable, and any other assumed parameters used for these calculations. Please provide descriptions and citations to support the assumptions, together with any documents, analyses, or forecasts relied upon to calculate such parameters.

A.2-18. In the interest of performing more expansive, detailed energy and capacity market modeling, as well as to obtain independent, objective analysis concerning possible RTO membership, the Companies engaged Guidehouse, Inc. to assist the Companies in developing the energy and capacity market costs and benefits reported in the 2022 RTO Membership Analysis. Because Guidehouse is an independent, third-party consultant with the requisite expertise to perform detailed RTO market modeling, the Companies did not possess the requested documents prior to receiving this request. In addition, certain other Sierra Club requests seek information the Companies did not possess at the time of these requests. Therefore, in this request and the requests that follow, the Companies have indicated that they obtained the requested information from Guidehouse as appropriate.

Note that all references to "PSO" are to Power System Optimizer.

Guidehouse has provided the following responses:

a. Confirmed. Guidehouse used PSO's Capex capabilities to approximate capacity expansion results. Manual adjustments were made as necessary in order to streamline production cost modeling and avoid unrealistic reserve penalties.

b. See the attachments being provided in Excel format by Guidehouse.

c. As described above, Guidehouse used PSO's capabilities to create initial results. Manual adjustments were occasionally made following the capacity expansion runs prior to running the production cost runs. Inputs generally rely on NREL's Annual Technology Baseline https://data.openei.org/submissions/5716, and are combined with Guidehouse's independent views which are shaped by professional opinion and client interactions.

   Manual adjustments were made to the results of the capacity expansion runs for a couple reasons. Firstly, adjustments were made to compensate for various anomalous production cost outputs. For example, if production cost runs yielded a noticeable number of hours with reserve violations it would be indicative that the reserve margin was likely too small. In this case some capacity would be added in order to reduce and/or eliminate any hours during which these violations were occurring. Secondly, adjustments were made because the capacity expansion and production cost simulations in PSO are not performed concurrently. It can be onerous in PSO to translate the Capacity Expansion outputs to Production Cost inputs. This can lead to potentially slow and costly iterations between model runs.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Sierra Club's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 2-26

Responding Witness: David S. Sinclair

Q.2-26. Please refer to Attachment 1 in response to Sierra Club's Initial Request for Information question 12a, and to file 20221017_LAK_ExpPlanFixedCosts_2022RTOAnalysis_D02.xlsx therein, as well as "2022 RTO Membership Analysis", Exhibit 2, Appendix B "Capacity Additions and Retirements", Table B5 at page 4-69:

a. On worksheet "RRProfiles" of the referenced file, rows 2 – 6 contain an annualization profile for the capital costs of each of five types of new entrant generator, reflecting the percent of capital cost accrued in each of many years. Please provide the method for developing each of these capital annualization profiles, including input parameters (such as discount rate, depreciation schedule, etc.), real vs. nominal, descriptions and citations supporting those input parameters, and all input files supporting calculation of the annualization profile (in electronic, machine readable format with formulae intact).

b. On worksheet "RTO" of the referenced file, please confirm that the capacity additions by year labeled "wind" in column E in fact refer to the capacity expansion model results for utility-scale solar, or if not, then please explain the discrepancy relative to Table B5. Please confirm that the capital costs of wind were applied to utility solar entry in the calculation of net benefits for the RTO case, or it not, please explain.

A.2-26.

a. See attached. The referenced annualized profiles reflect the calculation of revenue requirements for a generic capital expenditure with applicable economic assumptions, as a percentage of total capital spent.

b. Confirmed. This file includes an error in that the expansion plan data for the RTO cases were transposed among the storage, solar, and wind columns on the "RTO" worksheet. After making this correction and the corrections noted in the response to Question No. 24, the Companies continue to conclude that

RTO membership is not in customers' best interest at this time. For an updated *2022 RTO Membership Analysis*, see attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. For updated workpapers, see attachments being provided in Excel format.[5] Revisions are highlighted in blue.

[5] Attachments 2-6 are updates to specific workpapers (as indicated in the filenames) that were provided in Attachment 1 to SC 1-12(a). Attachments 5-6 are provided by Guidehouse.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Sierra Club's Supplemental Request for Information
Dated April 14, 2023

Case No. 2022-00402

Question No. 2-30

Responding Witness: Stuart A. Wilson

Q.2-30. Please refer to Exhibit SAW-1, sponsored by Stuart A. Wilson, Table 14 at page D-23 and Table 15 at page D-24.

a. Please confirm that the Reference Portfolio described in row 1 of Table 14 plus 480 MW of SSCT exceeds the target summer and winter reserve margin. With reference to Table 15, please confirm that your analysis shows that the loss-of load- expectation (LOLE) of that portfolio is 3.87 days in 10 years (or, if not, please state the LOLE of that portfolio).

b. Please confirm that the LOLE analysis shows that the Reference Portfolio with supply additions to meet the 17% and 24% target reserve margin would yield an LOLE reliability metric more than three times worse than the 1-in-10 guideline set by NERC. If not, please state what the LOLE is at the 17% and 24% target reserve margins.

A.2-30

a. Both statements are confirmed.

b. Confirmed. Please note that 17% and 24% are the minimums of the summer and winter target reserve margin ranges, respectively, and are determined as the Companies' "economic" reserve margins. In the 2021 IRP, the Companies determined the high end of the target reserve margin range as 24% in the summer and 35% in the winter. Those reserve margin levels meet the 1-in-10 reliability guideline.

EXHIBIT ACL-4

PJM Hourly Load Forecast Spreadsheet

(Excel File Provided Separately)

EXHIBIT ACL-5

RTO Study Production Costs and Capacity Additions Spreadsheet

(Excel File Provided Separately)

EXHIBIT ACL-6

2022 RTO Membership Analysis

(Updated May 2023)

2022 RTO Membership Analysis

PPL companies

November 2022

UPDATED MAY 2023

Contents

1 Executive Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") performed this study to evaluate whether membership in a Regional Transmission Organization ("RTO") may provide potential net benefits to retail and wholesale requirements customers. Building on the work of the Companies' previous RTO membership studies, this study provides both quantitative and qualitative analyses to determine if seeking RTO membership at this time would likely be net beneficial for customers. Based on the analyses presented herein, the Companies conclude that seeking RTO membership at this time likely would not benefit customers.

Notable Change from Previous Studies: Focus on PJM Membership

Unlike the Companies' previous RTO membership studies, the 2022 RTO Membership Analysis exclusively studies the costs and benefits of PJM membership. This study focuses solely on PJM membership for two reasons: (1) MISO has significant reliability concerns; and (2) all of the Companies' past RTO membership studies have shown that MISO membership would not be beneficial for the Companies' customers.

More In-Depth Quantitative Analysis Shows PJM Membership Not Currently Beneficial

Focusing on possible PJM membership, the Companies performed a more in-depth quantitative analysis than in previous RTO studies. That began with identifying the primary categories of costs and benefits associated with RTO membership shown in Table 1, which are similar to those the Companies analyzed in previous RTO studies:

Table 1: RTO Membership Cost and Benefit Components

Costs	Benefits	Cost or Benefit
• RTO Administrative Fee • Energy Uplift • Transmission Expansion • Internal Staffing & Implementation • Lost Transmission Revenue • Lost Joint Party Settlement Revenue	• Miscellaneous Avoided Fees • Potential Reduction or Elimination of Transmission De-pancaking Costs • Avoided Capacity Savings • RTO Capacity Market Impacts	• RTO Energy Market Impacts

For the 2022 RTO Membership Analysis, the Companies desired to perform more expansive energy and capacity market modeling than in the Companies' prior RTO studies. The Companies researched reputable third-party consultants and ultimately engaged

Guidehouse, Inc. to assist the Companies in developing the energy and capacity market costs and benefits reported in the 2022 RTO Membership Analysis.[1]

The 2022 RTO Membership Analysis also evaluates more future scenarios over a longer period than the Companies' previous RTO studies: two fuel-price cases (mid and high) and two CO_2 regulatory cases (none and 70% reductions from 2010 levels by 2040), all four of which the Companies studied over a 16-year period.

As shown Figure 1 below, the more in-depth quantitative analysis in this RTO membership study indicates that joining PJM at this time likely would not be beneficial for customers.

Figure 1 - Net Benefits/(Costs) of Joining PJM (Nominal $M)

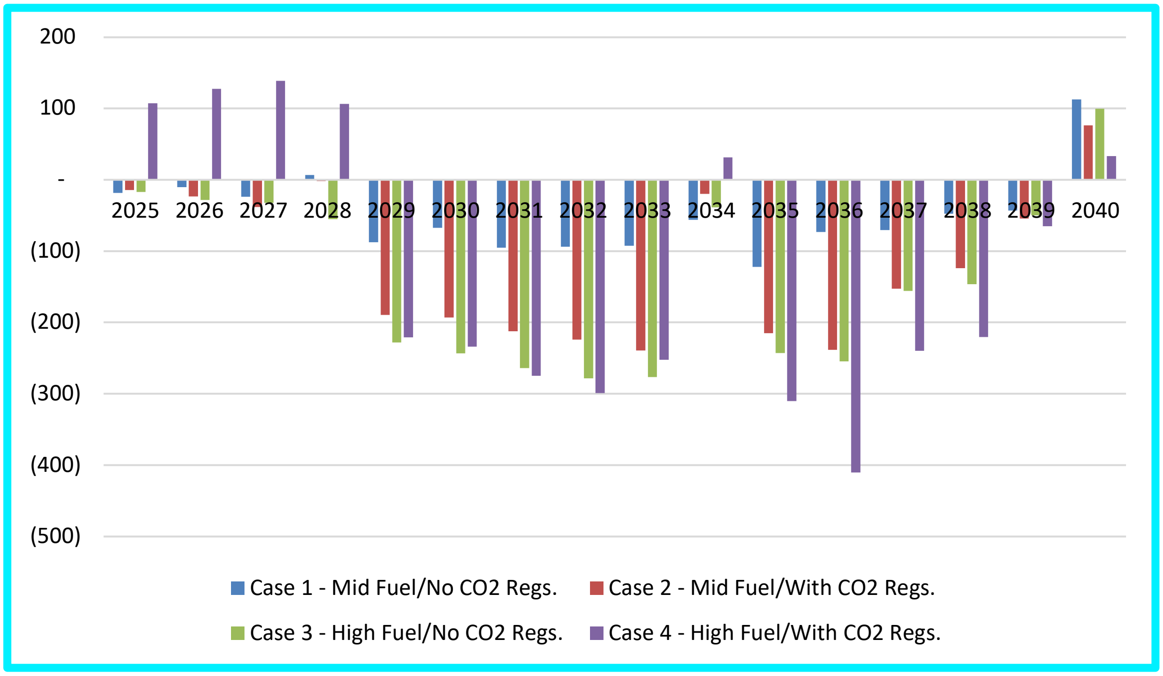


Figure 1 reflects that PJM membership offers the potential benefit of increased energy sales into PJM in the early years when the Companies are longer on capacity, especially in Case 4, which assumes high fuel prices and national CO_2 reduction regulations. But in Cases 1-3, PJM's fixed costs exceed these energy market benefits in the early years. Beginning in 2029, as more of the Companies' coal units retire, avoided capacity savings in PJM only partially offset fixed and energy costs, resulting in PJM membership being higher cost than

[1] Guidehouse has extensive experience serving as a market consultant in the North American power markets supporting M&A on greenfield and brownfield power projects, gas and transmission expansions, and regional planning studies. Guidehouse has also provided Independent Market Consultant Reports, including analyses of long-term electricity market price forecasts, transmission and congestion, import-export forecasts, and detailed market overviews and reports. For further information about Guidehouse, see Exhibit 1. For the complete Guidehouse analysis, see Exhibit 2.

standalone operation in all cases and in every year except 2034 and 2040.[2] The tables in Appendix 1 show the annual cost and benefit components of these figures.

Table 2 below shows the same results in nominal dollars and in 2022 present value ("PV") dollars discounted using a weighted average cost of capital for the Companies.[3]

Table 2 - Net Benefits/(Costs) of Joining PJM ($M)

	Case 1	Case 2	Case 3	Case 4
Nominal	(783)	(1,864)	(2,212)	(1,983)
2022 PV Dollars	(421)	(966)	(1,166)	(848)

In sum, the Companies' quantitative analysis of PJM membership shows that in both nominal and present value terms, PJM membership likely would not be beneficial for the Companies' customers at this time.

Guidehouse Capacity Expansion Modeling Favors NGCC and Solar

As part of its energy and capacity pricing modeling, Guidehouse conducted its own capacity expansion plan modeling for the Companies both as standalone utilities and as PJM members. The capacity expansion plans created by Guidehouse's models added natural gas combined cycle ("NGCC") and solar capacity to the Companies' generation portfolio in the near and medium term as the Companies' coal units retire. Notably, by 2034 (i.e., by the time the model assumed Mill Creek Units 1 and 2, Brown Unit 3, and Ghent Units 1 and 2 would retire) both the standalone and PJM-membership capacity expansion plans included two NGCC units totaling almost 1,000 MW, 400 MW or more of simple-cycle combustion turbine ("CT") capacity, and 750 MW of utility solar capacity. This suggests that replacing retiring coal capacity with NGCC and solar capacity would not prejudice the Companies' customers if PJM membership became advantageous in the next 10-15 years.

Qualitative Analysis Shows Prudence of Wait-and-See Approach to PJM Membership

The Companies' quantitative analysis alone demonstrates that seeking PJM membership at this time is not prudent, and a number of qualitative considerations further bolster that conclusion:

- PJM's market rules, particularly those concerning capacity markets, remain in flux. PJM is experiencing the same capacity transformation most of the nation is

[2] The net benefits shown in 2034 and 2040 result primarily from differences in expansion plan timing.
[3] The weighted average cost of capital used for this discounting is 6.43%.

undergoing, and it is working to optimize capacity markets to ensure reliability at reasonable costs. But that is a work in progress, making it difficult to forecast accurately what PJM's market rules—and their financial impacts on customers—might be in the near and medium term.

- Although not to the same extent as MISO, PJM has reliability concerns that raise doubt about the ability of new load-serving members to assume confidently that carrying less capacity in PJM—the primary basis for long-term RTO membership benefits—will result in reliable service for the customers they serve.

- The Companies' quantitative analysis assumes zero cost for hedging or otherwise managing price risk in an RTO, and it further assumes relatively modest transmission cost allocations for other members' transmission expansion projects. Those assumptions may prove to be reasonable, but the risk associated with them is primarily that they underestimate RTO costs, not that they overestimate them.

- It is reasonable to assume the Companies could obtain PJM (or other RTO) membership at any time.

- It is equally reasonable to assume—based in large part on the Companies' own experience exiting MISO—that exiting an RTO would be costly and time-consuming, if possible at all. Because of the difficulty and low likelihood of exiting an RTO, it is in customers' interest for projected benefits of RTO membership to be both durable and reasonably likely across broad range of future scenarios before seeking RTO membership.

- Based on the Guidehouse capacity expansion plan modeling, it appears that pursuing a capacity expansion plan for the Companies that included both NGCC and solar capacity in the near and medium term would result in a "no regrets" outcome if PJM membership became prudent in the next 10 to 15 years.

These qualitative factors show that, if anything, the Companies' and Guidehouse's analyses overestimated possible RTO benefits and underestimated RTO costs by assuming stable market rules, RTO resource adequacy and reliability, low transmission expansion costs, and zero cost associated with hedging RTO price risk. They further show that there is no particular advantage to seeking RTO membership now because the opportunity will remain open in the future. Finally, they show that capacity expansion plans that would ensure reliable and economical service as standalone utilities should also be advantageous if the Companies later become RTO members.

In short, the Companies' quantitative and qualitative analyses are fully aligned: RTO membership is not in customers' best interest at this time. The Companies will perform another RTO Membership Study in 2023, reassessing any changes in the outlook for RTO reliability as indicated in NERC, RTO, and other reports, as well as updating the inputs to energy and capacity market models.

2 Background

The following background information provides helpful context for the Companies' quantitative and qualitative analyses in the 2022 RTO Membership Analysis.

2.1 The Companies' History and Experience with RTOs

The Companies were founding members of MISO, operating within MISO from 2002 until September 1, 2006, when the Companies terminated their MISO membership with Kentucky Public Service Commission ("Commission") approval.[4] Although the Companies are no longer members of MISO, the Companies are market participants in, and regularly transact in, both MISO and PJM.

2.2 The Companies' Previous RTO Membership Analyses

Since exiting MISO, the Companies have periodically conducted high-level analyses to evaluate whether full membership in an RTO might be beneficial to their customers, and they currently have an obligation to file an annual RTO analysis.[5] The Companies filed their 2021 RTO Membership Analysis with the Commission on October 19, 2021.[6]

The Companies based their 2022 study on the Companies' previous RTO Membership Analyses with the addition of third-party energy and capacity market modeling by Guidehouse to reflect the best available and current data.

2.3 Approach to RTO Membership Decision

The decision to join an RTO requires not only a broad evaluation of detailed assumptions and quantitative modeling, but also a fundamental business review of the desired operating environment considering the required changes to the Companies' overall operating practices and their potential impacts on customers. Fundamentally, joining an RTO is transferring functional control of generation and transmission operations to the RTO and participating in current and future RTO-administered wholesale markets, however those markets for generation and load may develop. Significant risk exists that operation under

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[4] In 2003, the Commission initiated on its own motion an investigation into the Companies' membership in MISO to determine if that membership provided net benefits to customers. *In the Matter of: Investigation of the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, Case No. 2003-00266, Order (Ky. PSC July 17, 2003). The Commission determined in late May 2006 that ongoing MISO membership was not likely to provide ongoing net benefits to customers and authorized the Companies to terminate their MISO membership. Case No. 2003-00266, Order (Ky. PSC May 31, 2006).

[5] Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, Case No. 2018-00294, Order at 29-30 (Ky. PSC Apr. 30, 2019); Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, Case No. 2018-00295, Order at 33 (Ky. PSC Apr. 30, 2019).

[6] In accordance with the Commission's April 30, 2019 Orders in Case Nos. 2018-00294 and 2018-00295, the Companies filed their 2020 RTO Membership Analysis in the post-case correspondence of those proceedings.

the rules of the RTO will not be consistent with the Companies' obligations to reliably serve customers at the lowest reasonable cost. RTO policies, requirements, and operations are driven by the changing regulatory landscape, variable market conditions, and diverse stakeholder groups that represent varying interests across multiple states.[7] RTO members, their stakeholders, and state regulators cede control over significant revenue streams, cost incurrence and allocation, and decisions impacting the transmission system and generation fleet – and ultimately cost of service to customers. It is unlikely that a decision to join an RTO will be reversible in the future, so it is critical that the Companies have adequate insight into the potential future structure and market rules of the RTO.

2.4 RTO versus standalone responsibilities

Responsibilities are fundamentally different for utilities that are part of an RTO versus standalone operation. Before considering potential financial costs and benefits that are highly dependent on market forecasts and RTO market rule developments, it is important to understand the functional responsibilities of RTO members and non-members across the spectrum of Balancing Authority, Generation, and Transmission activities as described in Table 3.

[7] PJM operates in all or parts of 13 states and the District of Columbia to manage over 85,000 miles of high voltage transmission lines and 185,000 MW of generating resources.

Table 3 - Functional Responsibilities

Activity	Current / Stand Alone	RTO Member
Generation Commitment / Dispatch	Self-managed to meet customers' load	RTO/market controlled
Generation Reliability	Self-managed	Market influenced; RTO rules
Reliability Metrics	Self-managed	Market influenced
Changing Market Design / Rules	N/A	RTO controlled
Fuel and Energy Costs for Customers	Self-managed; regulatory review / low volatility	Subject to Locational Market Price ("LMP"); highly volatile
Renewable integration	Self-managed	Market influenced
Resource Adequacy	Self-managed	Market influenced
Resource Planning	Low cost reliable service responsibility	Manage market risk
Stakeholder / Customer desires	More narrow / alike	Wide ranging / dissimilar
Transmission Cost Allocation	Self-managed	RTO controlled
Transmission Reliability	Self-managed	RTO influenced
Transmission Expansion Planning	Self-managed and ITO[8]	RTO oversite and influence
Transmission Operations	Self-managed	RTO oversite and approval
ATC Calculations and OASIS Administration	Self-managed; RC[9] and ITO	RTO managed
Transmission Compliance	Self-managed	RTO managed (primarily)

As RTO members, the Companies would no longer commit units to serve native load customers based on the Companies' load forecast and unit economics as occurs in today's standalone operating environment. Instead, the RTO would dispatch the Companies' generating units, leaving the Companies' customers subject to market LMPs that reflect broader RTO load and system conditions, transmission congestion, and RTO market rules. In an RTO, the Companies' activities would focus on meeting RTO tariff requirements and attempting to hedge market risk through the use of Auction Revenue Rights ("ARRs") and Financial Transmission Rights ("FTRs"). PJM describes FTRs as a way to "allow market participants to offset potential losses (hedge) related to the price risk of delivering energy to the grid. FTRs are financial contracts entitling the FTR holder to a stream of revenues (or charges) based on the day-ahead hourly congestion price difference across an energy

[8] As non-RTO members, the Companies have an Independent Transmission Operator ("ITO"), which helps ensure impartial transmission system administration. TranServ is the Companies' current ITO.
[9] As non-RTO members, the Companies have third-party Reliability Coordinator ("RC"). TVA is the Companies' current RC.

path."[10] ARRs "are entitlements allocated annually to firm transmission service customers that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. ARRs are another hedging mechanism available to PJM's transmission service customers."[11] In summary, the Companies' primary focus as RTO members would shift from supporting customers with reliability and economic unit dispatch to optimizing transactions to meet RTO market rules and reduce customers' exposure to financial risk.

2.5 MISO Reliability Concerns and Study Focus on PJM

The Companies' 2022 RTO Membership Analysis focuses solely on a PJM membership evaluation due to increasing uncertainty about MISO's reliability related to the lack of generation resources in the MISO footprint, as well as the Companies' consistent findings in all their previous RTO membership analyses that potential MISO membership was always less favorable than potential PJM membership. If MISO's reliability concerns resolve, the Companies will again include an evaluation of MISO membership in future RTO membership analyses.

Recent reports from NERC and MISO itself indicate a state of increasing reliability risk within MISO. NERC's 2022 Summer Assessment asserts that MISO faces a capacity shortfall in the North and Central areas, resulting in high risk of energy emergencies during summer conditions. Four of eleven zones entered the annual Planning Resource Auction ("PRA") without enough capacity to cover their requirements.[12] MISO's PRA for planning year 2022/2023 indicated a 1.3 GW capacity shortfall in the North and Central regions, resulting in capacity prices clearing at the Cost of New Entry ("CONE") $236.66 / MW-Day.[13]

MISO stated in its 2022/2023 Planning Resource Auction Results presentation, "Zones 1-7 have an increased risk of needing to implement temporary, controlled load sheds."[14] In MISO's Summer 2022 Seasonal Assessment for Generation presentation (dated April 28, 2022), MISO indicated that "[u]nder typical demand and generation outages, MISO is projecting insufficient firm resources to cover summer peak forecasts."[15] Furthermore,

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[10] "Financial Transmission Rights", PJM, https://www.pjm.com/markets-and-operations/ftr.
[11] Auction Revenue Rights FAQs, PJM, PJM Learning Center - Auction Revenue Rights FAQs.
[12] "2022 Summer Reliability Assessment",https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf, North American Electric Reliability Corporation, May 2022, pg. 4-5
[13] "2022/2023 Planning Resource Auction Results", https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf, MISO, April 14, 2022, slides 2, 4.
[14] "2022/2023 Planning Resource Auction Results", https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf, MISO, April 14, 2022, slide 9.
[15] https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf, MISO, April 28, 2022, page 28.

"Emergency resources and non-firm energy imports are projected to be needed to maintain system reliability."[16]

MISO's capacity market structure continues to evolve in an attempt to catch up to these looming reliability risks. On August 31, 2022, FERC issued an Order conditionally approving changes to MISO's tariff to move its capacity market from an annual construct to a seasonal construct with four seasonal resource adequacy requirements.[17] In a concurring opinion to that Order, one FERC Commissioner expressed an "increasing[] concern[]" about "MISO's ever-decreasing excess reserve margins and MISO's apparent inability to retain sufficient dispatchable generation to ensure reliability and resource adequacy."[18] The Commissioner further characterized the market's inability to procure sufficient dispatchable generation as "a flaw so fundamental that it calls the justness and reasonableness of a market's resulting rates into question."[19]

These significant reliability concerns alone would be adequate cause to exclude MISO from this year's RTO study. But that exclusion finds further support in all of the Companies' previous analyses, which have uniformly found that, though no RTO membership was favorable for the Companies' customers, potential MISO membership was consistently less favorable than potential PJM membership. For example, in the Companies' 2021 RTO Membership Analysis, potential MISO membership was detrimental to the Companies' customers across all five years and all three cases studied, whereas the potential PJM membership results were mixed across the three cases.[20] The same was true in the Companies' 2020 RTO Membership Analysis across all ten years and all three cases studied.[21] It was therefore reasonable to exclude MISO from this year's study and perform a more in-depth quantitative analysis of possible PJM membership.

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[16] https://cdn.misoenergy.org/20220428%20Summer%20Readiness%20Workshop624245.pdf, MISO, April 28, 2022, page 28.

[17] *Midcontinent Independent System Operator, Inc.*, FERC Docket Nos. ER22-495-001 and ER22-495-002, Order Accepting Proposed Tariff Revisions Subject to Condition (FERC Aug. 31, 2022).

[18] *Id.*, Concurring Opinion of Commissioner Danly at 1-2.

[19] *Id.* at 2 ("A market's failure to procure sufficient capacity with the needed characteristics is a flaw so fundamental that it calls the justness and reasonableness of a market's resulting rates into question. Perhaps, given this systemic failure, Vistra Corp. was correct in describing MISO's capacity market as 'irreparably dysfunctional.'").

[20] Case Nos. 2020-00349 and 2020-00350, 2021 RTO Membership Analysis at 6 (Oct. 19, 2021).

[21] Case Nos. 2020-00349 and 2020-00350, 2020 RTO Membership Analysis at 21-22 (Mar. 31, 2020).

3 Quantitative Analysis of Possible PJM Membership

The quantitative analysis the Companies performed as part of the 2022 RTO Membership Analysis is the most rigorous, in-depth annual RTO analysis the Companies have performed to date. The analysis considered a longer time span than previous studies (16 years), involved more expansive energy and capacity modeling than previous studies with the assistance of a reputable third-party consultant, Guidehouse, and studied more future scenarios than previous RTO membership analyses.

This year's quantitative analysis is nonetheless fundamentally similar to previous years' studies: it uses high-quality assumptions about key inputs (e.g., load and fuel-price forecasts), develops possible future scenarios for study, identifies categories of costs and benefits likely to change between standalone versus RTO member operations, and then studies the effects of standalone versus RTO-member operations in the various scenarios.

As detailed and explained below, the conclusion of this year's quantitative analysis is the same as previous years' analyses: RTO membership is unlikely to benefit the Companies' customers at this time. But the quantitative analysis also shows that adding NGCC and solar capacity as the Companies' coal units retire is likely advantageous in both the standalone and PJM-member scenarios, indicating that adding such capacity would not prejudice the Companies' customers if RTO membership appeared to be beneficial in future analyses in the next 10-15 years.

In the following subsections, the Companies describe and explain their key input assumptions, the cases they developed for analysis, the various cost and benefit categories quantified, and the results of their and Guidehouse's analyses.

3.1 Key Input Assumptions

The Companies provided the following key inputs to Guidehouse to use in its energy and capacity modeling efforts and to use in developing different future scenarios (cases) to analyze.

<u>Load Forecast</u>

The Companies used their 2023 Business Plan load forecast for all years and cases studied in these analyses. As a simplifying assumption and to enhance comparability across cases studied, the Companies assumed load would not change between cases studied.

<u>Unit Retirements</u>

As a simplifying assumption, the Companies assumed the retirement schedule shown in Appendix 2 for their existing generating units across all cases studied. Notably, it includes significant coal unit retirements by the end of 2034: Mill Creek Units 1 and 2, Ghent Units 1 and 2, and Brown Unit 3.

Capacity Expansion Costs

The capital and operating and maintenance costs shown in Appendix 2, taken from the National Renewable Energy Laboratory's 2022 Annual Technology Baseline, informed the capacity expansion cost assumptions used by Guidehouse as it developed capacity expansion plans for the Companies in standalone and PJM-member operations.

Fuel Prices

The Companies used their 2023 Business Plan mid and high fuel price forecasts in these analyses. These forecasts included the impacts of increased fuel prices experienced since the Companies' 2021 Integrated Resource Plan filing and are significantly higher than both comparable fuel price projections in the Companies' 2022 Business Plan.

Carbon Dioxide Emission Regulations

The Companies asked Guidehouse to study two CO_2 emission regulation scenarios: one in which no new CO_2 emission regulations apply and another with a CO_2 reduction pathway consistent with an illustrative pathway proposed by the Intergovernmental Panel on Climate Change's ("IPCC") to limit global warming to 1.5 degrees Celsius applies.[22] Appendix 2 shows this assumed pathway of annual CO_2 reductions from 2010 levels. Guidehouse modeled the latter regulatory approach by applying a set of CO_2 shadow prices to achieve the necessary level of CO_2 reductions.

3.2 Cases Developed

The Companies determined that studying four total cases would provide a reasonable range of outputs to determine whether, on a quantitative basis, PJM membership might be beneficial for customers at this time. The four cases studied are:

1. Mid fuel prices and no CO_2 emission regulations
2. Mid fuel prices and CO_2 emission regulations
3. High fuel prices and no CO_2 emission regulations
4. High fuel prices and CO_2 emission regulations

[22] IPCC describes its "P3" pathway as "A middle-of-the-road scenario in which societal as well as technological development follows historical patterns. Emissions reductions are mainly achieved by changing the way in which energy and products are produced, and to a lesser degree by reductions in demand." See p. 14 of IPCC's 2018: Summary for Policymakers in: *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels in the context of strengthening response to climate change, sustainable development, and efforts to eradicate poverty* at https://doi.org/10.1017/9781009157940.001.

Of the four cases studied, the Companies believe Case 4 is the least likely; CO_2 emission regulations would tend to reduce the demand for fossil fuels, making persistent high fossil fuel prices less likely in that scenario (barring long-term supply constraints). The Companies' view is that the future is more likely to fall within the ranges of fuel prices and CO_2 restrictions modeled in Cases 1-3.

3.3 Costs and Benefits Analyzed

The Companies identified the following key categories of costs and benefits to consider regarding possible RTO membership. Note that the values of the costs and benefits for most of these categories do not change across the four fuel-price and CO_2-emissions cases because the value of the costs or benefits do not vary with fuel prices or CO_2 regulations.

Note also that the names shown in parentheses in the following headings reflect the names used for the cost and benefit categories shown in the cost-benefit tables for the four fuel-price and CO_2 cases in Appendix 1.

<u>RTO Administrative Fee ("PJM Admin Fee Cost")</u>

Every RTO has administrative costs it must recover from market participants. The Companies calculated the PJM administrative fee as a charge per MWh of load served. The RTO Administrative Fee does not change between cases because forecasted load does not vary across cases. The Companies calculated the administrative charge per MWh by escalating PJM's current charge by 2% per year to account for inflation, a conservative approach that tends to favor PJM membership by likely understating this cost given current inflation expectations. In nominal dollars, this cost increases from $19.2 million to $26.4 million per year.

<u>RTO Energy Uplift Cost ("PJM Energy Uplift (BOR) Cost")</u>

Every RTO must provide energy balancing operating reserves to ensure grid stability, and it must recover those costs (also called uplift costs) from market participants. The Companies calculated the PJM energy uplift cost as a charge per MWh of load served. Thus, the PJM Energy Uplift (BOR) Cost does not change between cases because forecasted load does not vary across cases. The Companies held the PJM energy uplift cost per MWh constant across the 16 years of the study at about $5 million per year in nominal dollars.

<u>Transmission Expansion Cost ("PJM Transmission Expansion Cost")</u>

Transmission planning and the allocation of expansion costs are major activities for RTOs. Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculation. The Companies estimated their allocation for projects documented in the RTEP within this analysis period using PJM's publicly posted RTEP project information. Consistent with the 2021 RTO Membership Analysis, in this analysis the Companies used PJM's most current RTEP project information (April 2022). Based on this information, the Companies' annual transmission expansion costs as PJM members are estimated to range from $17.8 million to $20.5 million, which values do not change between cases studied because the Companies' load (and therefore load share) does not change between cases.

Note that the Companies did not include in standalone operation possible transmission cost sharing in the Southeastern Regional Transmission Planning ("SERTP") region for FERC Order 1000 compliance because such future costs, if any, are unknown at this time. In addition, the Companies have not incurred any historical transmission project costs from the SERTP region. Such costs, if any, would offset the net costs shown for PJM Transmission Expansion Cost in this comparative analysis. The Companies do not anticipate that such SERTP-related costs would be comparable to the PJM Transmission Expansion Cost values included in this analysis.

Internal Cost of RTO Membership ("LG&E/KU Internal Implementation")

As RTO members, the Companies would incur a small amount of ongoing internal cost to enable them to participate in the RTO. The amounts the Companies have projected (all less than $1 million per year in nominal dollars) account only for anticipated hardware and software costs, including generation metering and software licensing costs. They do not include any personnel costs, and they do not vary across cases.

Lost Transmission Revenue ("LG&E/KU Lost Transmission Revenue")

In PJM, the Companies would have a zonal transmission rate that would be calculated in a similar fashion to how their transmission rate is calculated currently with the Companies as stand-alone transmission providers. In an RTO, the zonal transmission rate would apply to any network or point-to-point transmission that sinks in the zone, and the rate would continue to be based on the Companies' transmission revenue requirements. The analysis reflects an expected decrease in the sale of point-to-point transmission service resulting from RTO membership as the Companies would be under the RTO tariff and would not offer point-to-point transmission service directly. The lost transmission revenue included in this analysis ranges from $3 million to $8.6 million per year and does not vary between cases.

The Companies would also potentially receive an allocation of revenues from PJM based on the revenues that PJM collects for point-to-point transmission service that does not sink within the RTO (i.e., drive-out and drive-through transmission service). PJM has a mechanism for this allocation based on combinations of transmission plant in service ratio and flow-based derivations. Due to the difficulties in projecting drive-through and drive-out transmission use, as well as flows and ratios that would drive the Companies' allocation of revenues, the Companies did not attempt to determine the potential projected value of this allocation and therefore did not include it in this analysis. When the Companies were previously members of MISO, revenues for drive-through and drive-out transmission use were around $1 million annually. Due to the passage of time and changes in transmission facilities and use since the Companies' exit, the Companies did not use this historical performance value as a proxy but do believe it indicates that revenue from this service is not likely to be significant.

<u>Lost Settlement Revenue ("LG&E/KU Lost Joint Party Settlement Revenue")</u>

The Companies are parties to a settlement agreement between MISO, SPP, and others to address issues that arose from MISO's southern expansion to include Entergy and operate as a single Balancing Authority Area. Under the settlement agreement, MISO compensates SPP and others, including the Companies, for the use of these parties' systems. Although it is uncertain, the Companies determined it was reasonable to assume that compensation to the Companies under the settlement agreement would stop if the Companies were to integrate into PJM. The lost revenue ranges from $1.5 million to $2 million per year in nominal dollars and does not vary between cases.

<u>RTO Energy Market Benefits or Costs ("PJM Energy Market Benefits/(Costs)")</u>

The Companies engaged Guidehouse to model the potential energy and capacity market costs and benefits of joining PJM. This engagement was designed to allow for a third-party view and a more expansive level of modeling detail that is beyond the scope of the Companies' existing tools. The Companies' previous studies represented market prices as the result of market interactions, whereas Guidehouse attempts to model the interactions of all market parties. The Companies evaluated 11 potential consultants, interviewed a short list of three, and chose Guidehouse based on their more robust model and in-house modeling experience.

Guidehouse evaluated the potential costs and benefits related to PJM's energy and capacity markets in the following steps.[23]

Data alignment

The Companies provided detailed data for existing unit and system specifications, fuel price forecasts, and an assumed schedule for unit retirements.[24] Appendix 2 and Exhibit 2 detail these assumptions.

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[23] Guidehouse's full report of this analysis is attached as Exhibit 2.

[24] The assumed coal unit retirement schedule is consistent with the Companies' 2021 IRP.

Benchmarking

Guidehouse updated their existing models with the Companies' data and benchmarked their forecasts of generation and production costs to approximate the results of the Companies' existing 2023 Business Plan forecasts. These models included developing forecasts for energy and capacity market prices.

Standalone Scenario

Guidehouse developed a status quo scenario representing the Companies remaining standalone (i.e., outside PJM's footprint), including a forecast for replacement generation required to meet the Companies' summer and winter reserve margin targets. This scenario's assumptions include mid fuel prices and no future CO_2 emissions regulations and is referenced as Case 1-Standalone. Guidehouse developed potential capacity expansion plans for the Companies and PJM and forecasts for the Companies' cost to serve load, energy market prices, and the Companies' energy market imports and exports while outside PJM. The modeled expansion plan for the Companies is summarized in Table 4 below.

Table 4 - LG&E/KU Modeled Expansion Plan, Case 1-Standalone (Nameplate MW)

	Combined Cycle Gas	Simple Cycle Gas	Battery Storage	Solar	Wind
2025					
2026					
2027				100	
2028	484			200	
2029	484			100	
2030					
2031					
2032					
2033				100	
2034		400		250	
2035	484			250	
2036	800		100	400	
2037		200	200	250	100
2038		200	200	250	
2039		200	200	250	
2040	968	200	200		

RTO scenario

Guidehouse developed a scenario representing the Companies joining PJM, including a forecast for replacement generation required to meet PJM's resource requirements. This scenario's assumptions also include mid fuel prices and no future CO_2 emissions regulations and is referenced as Case 1-RTO.

Starting in 2028, to eliminate the uncertainty and risk exposure regarding PJM's future capacity market rules and prices, the Companies assumed they would follow PJM's existing fixed resource requirement ("FRR") provision. The FRR allows Companies to meet their resource adequacy requirements with their own resources outside of PJM's capacity market while still operating in PJM's energy markets.[25] Based on the Companies' assumed retirement schedule, Guidehouse developed an expansion plan to meet the FRR provision. Guidehouse also developed a capacity expansion plan for PJM and forecasts for the Companies' cost to serve load, energy market prices, and the Companies' energy market imports and exports as a PJM member. The modeled expansion plan for the Companies is summarized in Table 5 below.

[25] An FRR entity must annually demonstrate their ability to meet PJM's requirements and must commit specific resources to their capacity plan. FRR entities are subject to shortage and performance penalties if their resource plan is inadequate. See https://pjm.com/-/media/committees-groups/committees/mic/2020/20200108/20200108-item-04c-frr-alternative-education.ashx and https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx.

Table 5 - LG&E/KU Modeled Expansion Plan, Case 1-RTO (Nameplate MW)

	Combined Cycle Gas	Simple Cycle Gas	Battery Storage	Solar	Wind
2025					
2026					
2027					
2028	484			300	
2029				100	
2030					
2031					
2032					
2033				100	
2034	484	500		250	
2035			100	350	
2036	400			100	
2037		400	200	250	100
2038			200	250	
2039	484	400		250	
2040			200		

Note that the standalone and RTO expansion plans Guidehouse's model generated for the Companies both add almost 1,000 MW of NGCC capacity, 400 MW or more of simple-cycle CT capacity, and 750 MW of solar capacity by 2034.

The PJM energy market benefits and costs resulting from the Guidehouse analysis vary significantly by case and range from a benefit of over $300 million in a single year to a cost of almost $500 million, all in nominal dollars.

<u>Capacity Revenues ("PJM Capacity Market Benefits/(Costs)")</u>
In the RTO scenario, the Companies assumed they would sell capacity above PJM's FRR capacity requirements to meet load until 2028, when the assumed retirement schedule resulted in a capacity need under PJM's resource adequacy requirements. For the planning years of 2025/2026 and 2026/2027, the Companies forecasted potential revenues from PJM's capacity market based on PJM's projected resource requirements and historical capacity auction prices, capacity clearing rates, and peak load coincidence with the Companies, specified as follows:

- PJM's forecasted pool requirement of 9.18% on an unforced capacity basis.
- Guidehouse's forecast of capacity prices for the following planning years (in nominal dollars):
    - 2025/2026: $53.12/MW-day

  - 2026/2027: $69.35/MW-day
- The highest capacity auction clearing rates by resource type since PJM's 2016/2017 planning year:
  - Coal: 85.1%
  - Gas: 95.3%
  - Hydro: 97.5%
  - Solar: 87.8%
- The Companies annual peak loads have averaged 92% coincident with PJM's published annual peak loads since 2012.

The resulting capacity revenues are shown in Table 6 on a calendar year basis in nominal dollars and do not vary between cases.

Table 6 – Capacity Revenues for Case 1-RTO ($M nominal)

	Capacity (Revenues)
2025	(0.1)
2026	(0.1)
2027	(0.03)
2028-2040	0

<u>Avoided Capacity Savings ("Avoided Capacity Savings")</u>

Comparing the expansion plan for the RTO scenario to the standalone scenario results in the potential for avoided capacity savings due to PJM's lower resource obligations. The Companies modeled these savings by forecasting the difference in annual revenue requirements for capital recovery and fixed operating costs between the RTO and standalone scenarios, as summarized in Table 7. Generally, joining PJM offers the opportunity for avoided capacity savings over time due to PJM's lower resource obligations for members compared to the reserve margins the Companies must maintain on a standalone basis. The values below do not vary between cases.

Table 7 - Revenue Requirements of New Capacity (Nominal $M)

	Standalone	RTO	RTO Avoided Capacity Savings/ (Costs)
2025	0	0	0
2026	0	0	0
2027	16	0	16
2028	118	118	0
2029	205	132	(73)
2030	200	127	(73)
2031	195	123	(72)
2032	190	119	(70)
2033	200	132	(69)
2034	293	322	29
2035	409	392	(18)
2036	623	466	(157)
2037	742	617	(124)
2038	834	682	(152)
2039	925	858	(67)
2040	1,155	878	(278)

<u>Avoided Standalone Fees ("Avoided Fees (FERC, TVA RC, ITO, TEE)")</u>

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as the Companies are assessed outside of an RTO. For this analysis, the projected FERC assessment charges were included in RTO administrative charges. The amount that the Companies currently pay is included as a projected benefit to quantify properly the net change in cost.

RTO membership would also result in cost savings from the elimination of certain third-party services the Companies require in standalone operation. For the purposes of this analysis, the Companies assumed they would no longer need the current Independent Transmission Organization ("ITO") or Reliability Coordinator ("RC") services provided by TranServ and TVA, respectively. In addition, the analysis assumes the current reserve-sharing contract with TVA would no longer be needed.

The value of these avoided fees ranges from $7 million to $7.9 million annually in nominal dollars, which do not vary between cases.

Elimination of De-pancaking Costs ("LKE Elimination of De-Pancaking")

The Companies currently provide Merger Mitigation De-pancaking ("MMD") credits to certain entities importing from MISO.[26] For the purpose of this analysis, the Companies assumed all but MISO Schedule 26A would be eliminated if the Companies joined PJM.[27] The benefit amount from reducing MMD expense is based on such expenses included in the 2023 Business Plan. The value of de-pancaking elimination ranges from $0.4 million to $22.2 million annually in nominal dollars, and these values do not vary between cases.

3.4 Quantitative Analysis Results

The Companies' and Guidehouse's quantitative analyses show that in most years and all cases studied, PJM's energy markets are a net *negative* for customers due to having to purchase customers' energy requirements at LMP prices and not receiving sufficient offsetting energy market revenues. In most years and in all cases, the offsetting RTO-membership benefit of avoided capacity savings is insufficient to equal or exceed the net costs associated with PJM's energy markets. Adding to those results the persistent net negative impact of all other RTO-membership costs and benefits results in PJM membership being unfavorable on a nominal dollar basis across all four cases considered, as shown in Figure 2:

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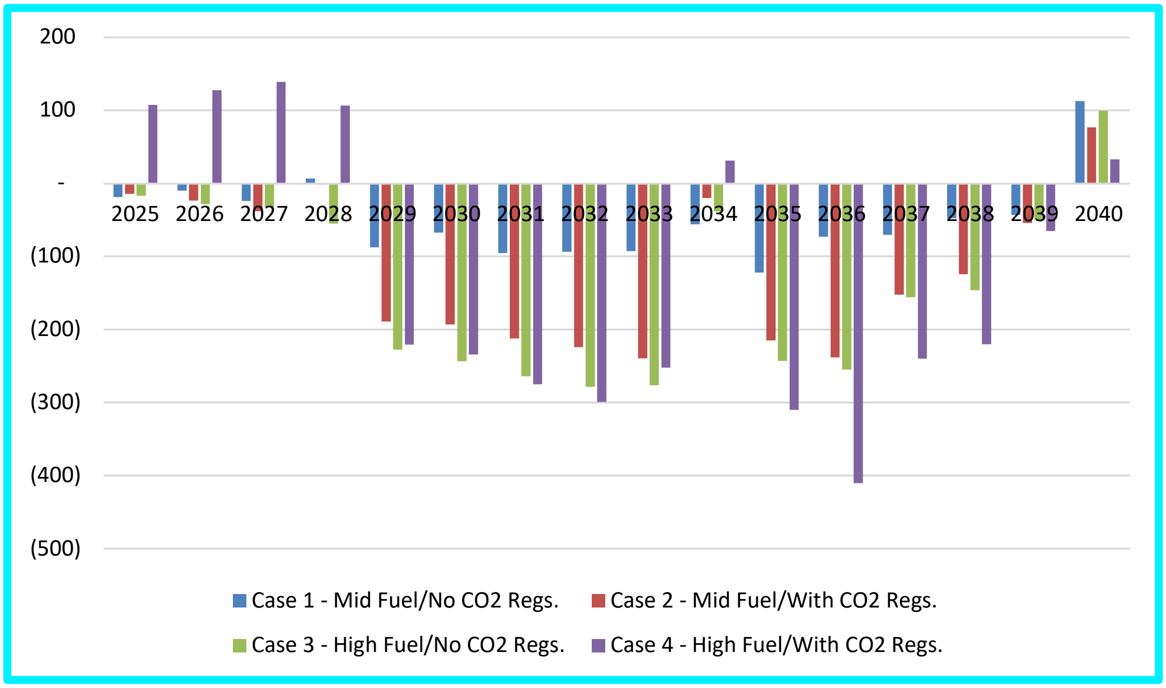
[26] The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. *See*, *E.ON U.S., LLC, et al.*, Docket No. ER06-1279-000. The Companies received FERC approval to eliminate this obligation, subject to the implementation of a transition mechanism for certain power supply arrangements. *See*, FERC Docket Nos. EC98-2-001, ER18-2162-000, EC98-2-002, ER18-2162-001, ER19-2396-000, ER19-2397-000, ER19-2396-001, ER19- 2397-001, EC98-2-003, ER18-2162-002, EC98-2-004, ER18-2162-003, ER19-2396-002, ER19-2397-002 and D.C. Circuit Court of Appeals Docket Nos. 19-1236, 19-1237, 20-1282, 20-1326, 20-1452, 20-1459, 21-1013, 21-1025 (consolidated). The Commission decision eliminating MMD was remanded to FERC by a decision of the Court of Appeals on August 4, 2022. A transition mechanism remains in effect pending FERC action on remand.

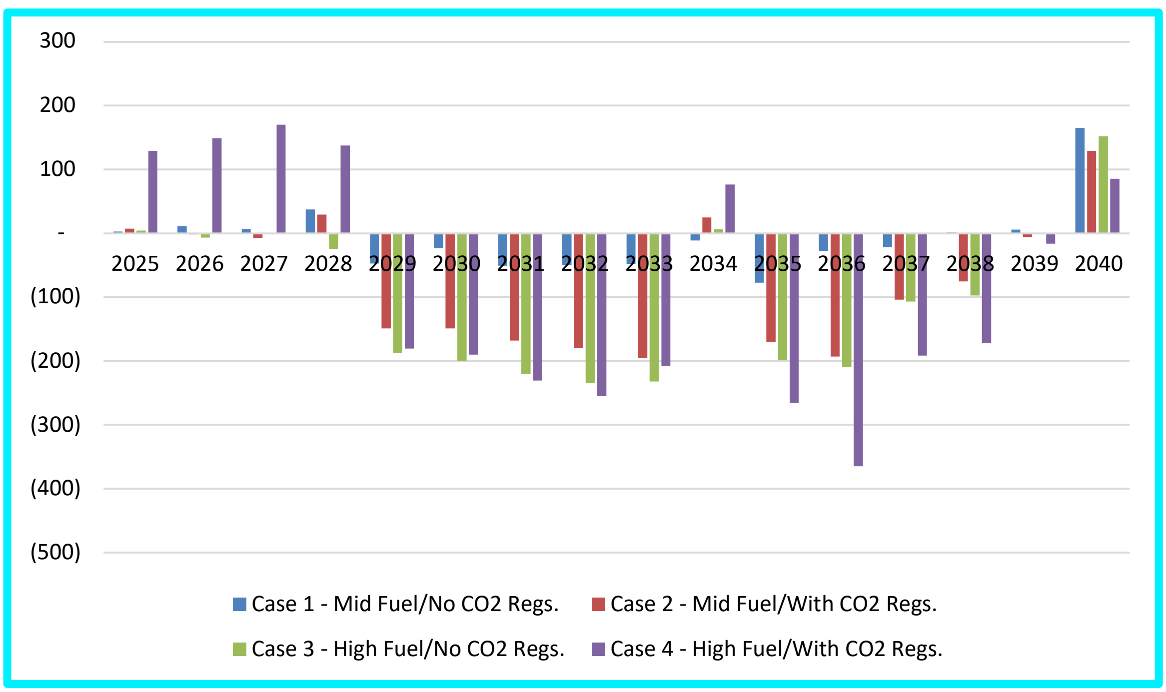
[27] This assumption weighs the benefit to joining the RTO higher but is reasonable in lieu of a FERC order providing direction in this area, as it is based on the current approved approach to pancaked rates at the MISO-PJM seam. FERC has required that transmission across the MISO-PJM be depancaked through the use of license plate rates. An exception to this general depancaking rule was created for MISO Schedule 26A in 2016. *See*, *Midwest Independent Transmission System Operator, Inc.*, 156 FERC ¶61,034 (2016) (Order on Remand from the Seventh Circuit finding that, in light of current conditions, the limitation on export pricing to PJM is no longer justified for MISO Schedule 26A charges).

Figure 2 - Net Benefits/(Costs) of Joining PJM (Nominal $M)



Comparing only the energy and capacity-related costs benefits of PJM membership (i.e., the sum of "PJM Energy Market Benefits/(Costs)," "PJM Capacity Market Benefits/(Costs)," and "Avoided Capacity Savings") produces similar results:

Figure 3 - Net Energy and Capacity Only Benefits/(Costs) of Joining PJM (Nominal $M)



These figures (and the data underlying them in Appendix 1) indicate that there is some potential for savings in the RTO in the early years, when the Companies are longer on capacity and could sell energy into PJM. But starting in 2029, as assumed coal retirements impact the Companies' capacity position, higher RTO energy costs are only partially offset by avoided capacity savings in the RTO, resulting in PJM membership being higher cost in most years. Table 8 shows the same result in tabular form:

Table 8 - Total Incremental Benefits/(Costs) by Case (Nominal $M)

	Case 1	Case 2	Case 3	Case 4
	Mid Fuel No CO_2 Reg.	Mid Fuel With CO_2 Reg.	High Fuel No CO_2 Reg.	High Fuel With CO_2 Reg.
2025	(19)	(14)	(17)	107
2026	(10)	(23)	(28)	128
2027	(24)	(38)	(32)	139
2028	7	(2)	(55)	107
2029	(88)	(189)	(228)	(221)
2030	(67)	(193)	(244)	(234)
2031	(95)	(212)	(264)	(275)
2032	(94)	(224)	(279)	(299)
2033	(93)	(239)	(276)	(252)
2034	(56)	(20)	(39)	31
2035	(122)	(215)	(243)	(310)
2036	(73)	(238)	(255)	(411)
2037	(71)	(152)	(156)	(240)
2038	(48)	(124)	(146)	(220)
2039	(43)	(54)	(50)	(65)
2040	113	77	100	33

These nominal dollar results are similar, though not identical, to the results in present value dollar terms. The tables below show the total net costs or savings of PJM membership in nominal dollars and in 2022 present value dollars discounted using a weighted average cost of capital for the Companies.[28]

[28] The weighted average cost of capital used for this discounting is 6.43%.

Table 9 - Net Benefits/(Costs) of Joining PJM ($M)

	Case 1	Case 2	Case 3	Case 4
Nominal	(783)	(1,864)	(2,212)	(1,983)
2022 PV Dollars	(421)	(966)	(1,166)	(848)

Table 10 - Net Benefits/(Costs) of Joining PJM—Energy and Capacity Only ($M)

	Case 1	Case 2	Case 3	Case 4
Nominal	(129)	(1,210)	(1,558)	(1,329)
2022 PV Dollars	(87)	(633)	(832)	(515)

Table 10 above is perhaps the most instructive of all. It suggests that even assuming all other PJM costs and benefits net to zero—including PJM administrative costs of $19 million to $26 million per year—the energy and capacity impacts of PJM membership would still not be net beneficial for customers. In all cases studied, PJM's energy and capacity impacts alone would result in net present value *costs* to customers ranging from $87 million to $832 million, making PJM membership unlikely to benefit the Companies' customers at this time.

3.5 Key Conclusions of the Quantitative Analysis

The Companies' enhanced quantitative analysis of PJM membership resulted in five key conclusions:

1. PJM's energy markets are largely a net negative compared to the Companies' standalone costs of production. This occurs in most years in which the cost of purchases to serve the Companies' load at PJM LMPs net of energy revenues from PJM exceeds the Companies' standalone cost of production.

2. PJM's capacity markets are of little value to the Companies because, as PJM members, the Companies would rarely have capacity in excess of PJM requirements. Capacity-related savings of PJM membership therefore result from the Companies carrying less capacity as PJM members than they would as standalone utilities.

3. The net negative impacts of PJM's energy markets far exceed the avoided capacity cost of PJM membership in most years and in most cases studied. Even if all other PJM costs and benefits netted to zero, PJM membership would not be in customers' interest at this time.

4. PJM's costs and benefits that do not vary with energy or capacity are likely to be persistently net negative, further causing PJM membership not to be in customers' interest at this time.

5. Guidehouse's modeled generation capacity expansion plans in the PJM-member and standalone scenarios are quite similar in the near and medium term. Thus, pursuing NGCC and solar capacity as standalone utilities should be a no-regrets approach if subsequent studies show PJM membership to be in customers' interests in the next 10-15 years.

4 Qualitative Analysis of Possible PJM Membership

In addition to the fundamental change in operating philosophy and the shifts in regulatory authority entailed by joining an RTO (as described in Section 2, "Background"), there are a number of qualitative and unquantified considerations regarding possible PJM membership that must factor into any RTO membership decision. Taking these considerations together, it appears that RTO membership is not advisable for the Companies and their customers at this time.

4.1 PJM Reliability Concerns and Increasing Renewable Generation

Although MISO faces the potential for nearer-term reliability issues, PJM is also mentioned in concerns about future reliability. PJM Power Providers ("P3"), a trade alliance of wholesale generating entities with a combined 67,000 MW of generating assets in PJM that is led by Glen Thomas, the former chair of the Pennsylvania Utility Commission, noted that "there are storm clouds looming on the horizon as it relates to reliability in PJM…."[29] P3 is concerned that PJM's proposed changes to its capacity market will erode price signals and illogically assume that gas-fired plants will be added to fill capacity needs despite their apparent ban in several PJM states due to climate change policies. In a protest filed with FERC on October 21, 2022, P3 asserted that "PJM's capacity markets are in crisis, and approval of the PJM filing will only deepen that crisis and further challenge reliability issues in PJM."[30]

Monitoring Analytics, the PJM Market Monitor, has also expressed concern about PJM's approach to calculating Effective Load Carrying Capability ("ELCC"): "But PJM's approach to calculating ELCC values by technology is badly flawed. Fixing the PJM approach to ELCC is a manageable task if there is a shared goal of letting markets reflect the actual, marginal contribution of all types of capacity (including thermal resources) to reliability without assumptions that arbitrarily favor some resource types. ELCC is also not a complete answer to defining a homogeneous product. Regardless of the ELCC value, solar energy will not be available at night and wind energy will not be available when the wind is not blowing. Reliability is not correctly defined as supplying energy during only a limited number of hours. The obligation of capacity resources is to offer energy in all 8,760 hours of the year."[31]

[29] "Reliability storm clouds loom for PJM amid transition – executive", S&P Capital IQ, August 2, 2022.
[30] *PJM Interconnection, L.L.C.*, FERC Docket No. ER22-2984-000, Protest of the PJM Power Providers Group at 3 (Oct. 21, 2022).
[31] "2022 Quarterly State of the Market Report for PJM: January through June", Monitoring Analytics, August 11, 2022, pg. 4.

In December 2021, PJM outlined several significant challenges facing their operating structure and markets in a whitepaper entitled *Energy Transition in PJM: Frameworks for Analysis*.[32] Traditional spinning resources provide essential reliability services (inertia, frequency response, ramping, regulation, black start capability, etc.) that will decline in PJM as renewable resource penetration increases, requiring market reforms. Transmission congestion impacts from an accelerated increase in renewable penetration could increase the number of congested hours by 50%. Although PJM did not simulate transmission expansion plans in their analysis, they note that transmission upgrades "are likely needed to integrate the future renewable generation."[33] A follow-up whitepaper published by PJM in May 2022, *Energy Transition in PJM: Energy Characteristics of a Decarbonizing Grid*,[34] further highlighted these challenges. PJM noted that "thermal resources performed a critical role in maintaining reliability" in scenarios with high renewable penetration as these resources will be needed to ramp drastically to meet the load as intermittent renewable resources production varies.[35]

This lends uncertainty to longer-term PJM reliability and potential changes in PJM market rules, but based on the specific issues raised by NERC and MISO, the Companies assess that the near-term reliability concerns are clearly greater in MISO.

As discussed in the Companies' 2021 RTO Membership Analysis, RTOs could be an attractive option for supporting a clean energy transition. The recent passage of the Inflation Reduction Act ("IRA") further encourages additional renewable generation. The diverse geography, resources, and loads in an RTO allow for the integration of higher penetration of intermittent resources than what the Companies could likely achieve on a standalone basis and potentially at lower integration costs due to the likely larger intra-hour balancing capabilities of a larger footprint. Given the reliability concerns discussed above, it remains unclear whether RTOs are prepared to sustainably integrate increasing levels of renewables and replace dispatchable generation while reliably meeting customers' energy needs at every moment. New renewables, especially wind resources, will likely require significant transmission investments to move renewable power to load centers. Depending on these

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32 https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211215/20211215-item-09-energy-transition-in-pjm-whitepaper.ashx, PJM, December 15, 2021.

33 https://pjm.com/-/media/committees-groups/committees/mrc/2021/20211215/20211215-item-09-energy-transition-in-pjm-whitepaper.ashx, PJM, December 15, 2021, pg. 20.

34 https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220517-annual/item-06---energy-transition-in-pjm-emerging-characteristics-of-a-decarbonizing-grid.ashx, PJM, May 17, 2022.

35 https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220517-annual/item-06---energy-transition-in-pjm-emerging-characteristics-of-a-decarbonizing-grid.ashx, PJM, May 17, 2022, pg. 5 and 22.

and other variables, it could be more cost-effective for the Companies to be on their own transition path rather than that of the RTOs.

4.2 The Companies' Generation Reliability Metrics Suggest RTO Membership Would Not Improve Reliability of Companies' Service

Equivalent Forced Outage Rate ("EFOR") and Equivalent Unplanned Outage Rate ("EUOR") are standard industry metrics that provide a view of the reliability performance of a generation unit or a generation fleet. EFOR reflects times when generation is forced out of service while EUOR also encompasses short term unplanned maintenance outages; both metrics include derated portions of unit capacity. Figure 4 and Figure 5 contain a three-and-a-half-year history of LG&E and KU's EFOR and EUOR compared to the Reliability First Corporation's ("RFC") top quartile and average performance for similar sized baseload units. RFC's boundaries overlap both MISO and PJM; thus, it serves as a proxy for generation within PJM. The Companies' generating fleet continued its strong reliability performance in 2021 and 2022.

Figure 4 - Equivalent Forced Outage Rate

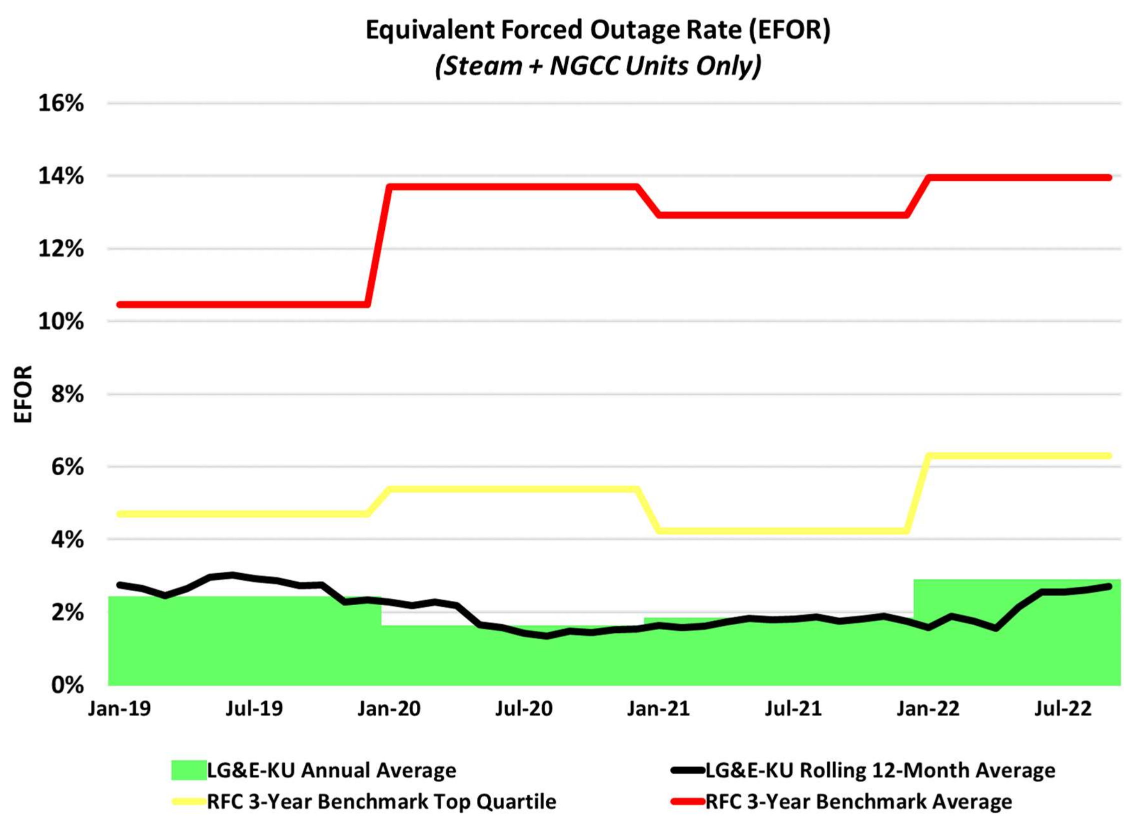
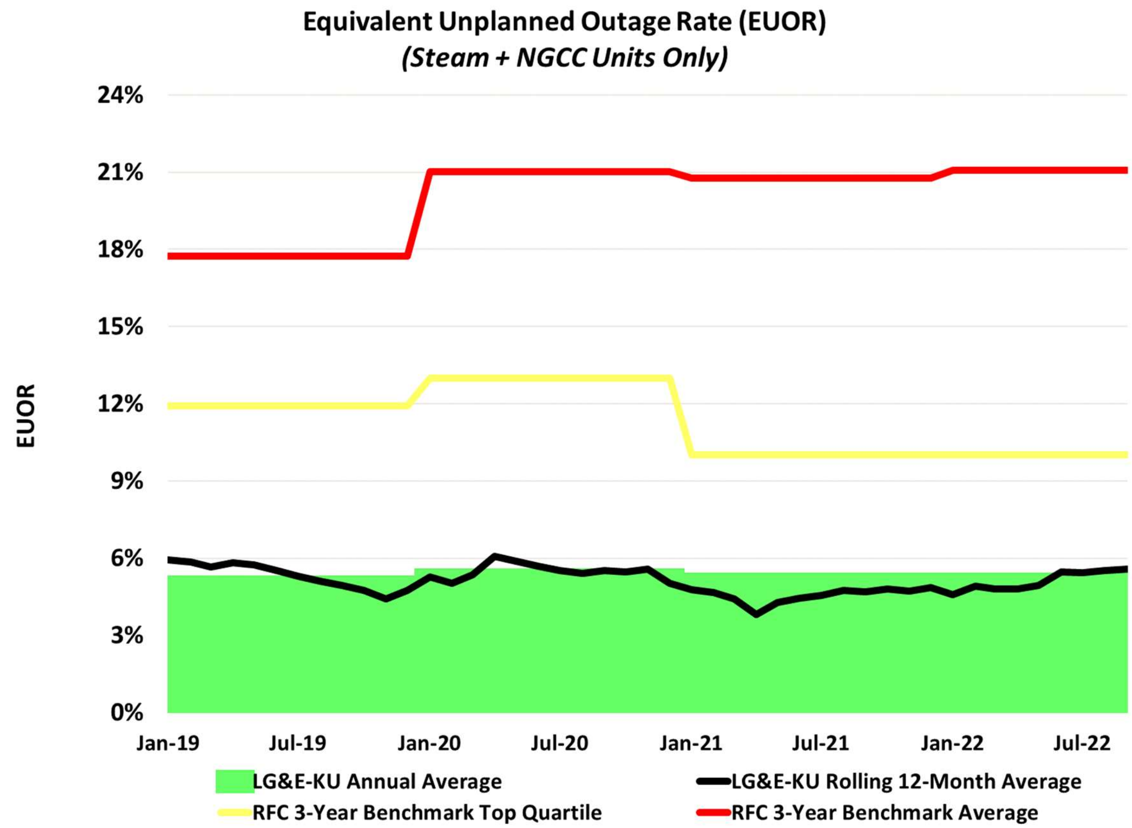


Figure 5 - Equivalent Unplanned Outage Rate



Higher than expected EFOR and EUOR increase the likelihood of multiple generation outages occurring concurrently, potentially leading to a capacity shortfall and subsequent energy deficiency.

During an Energy Emergency, a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected load obligations.[36] An Energy Emergency Alert ("EEA") is initiated on that entity's behalf when such conditions are present. As such, EEAs can be an indicator of capacity issues within an RTO. Since exiting MISO in 2006, the Companies have never experienced a resource shortage impacting their load service requiring declaration of an EEA.

The Companies have a long history of reliably serving the energy needs of their customers, even during extreme weather events. The generation reliability performance metrics[37] quantitatively show the Companies' planning and execution continue to excel beyond

[36] Definition from NERC Glossary of Terms
[37] RTO transmission reliability metrics are not available.

neighboring utilities that participate in RTOs. Nothing in this data suggests that there is reason to believe that overall customer reliability would improve by joining an RTO.

4.3 PJM Market Rules Continue to Be in Flux and a Cause for Concern

PJM's market rules, particularly those concerning its capacity markets, continue to be in flux and, as characterized by PJM's Independent Market Monitor, "flawed." Notably, PJM Independent Market Monitor's "Analysis of the 2023/2024 RPM [Reliability Pricing Model] Base Residual Auction [("BRA")]" released on October 28, 2022, states, "The combined impact of the identified market design flaws was to reduce capacity market revenues by 24.3 percent in the 2023/2024 BRA. The identified market design flaws are: the shape of the VRR [Variable Resource Requirement] curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports."[38] The Independent Market Monitor's analysis went on to state, "Capacity market prices in the 2023/2024 BRA were the result of both competitive forces *and significantly flawed market design*."[39] These were the Independent Market Monitor's comments on the *improved* 2023/2024 BRA; the analysis noted that the previous two capacity auctions were even more flawed and required rule changes: "The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed …. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and noncompetitive outcomes in both auctions."[40]

The purpose of raising these issues is not to disparage PJM; rather, it is to recognize a further reality also acknowledged by the Independent Market Monitor, namely, "Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance."[41] This ongoing process of rule changes may be necessary for the PJM capacity markets to achieve competitive outcomes as the markets remain in their infancy, but it is also a compelling reason to maintain a wait-and-see posture outside the PJM construct until its market rules stop changing, at least with such frequency and magnitude.

4.4 Quantitative Analysis Assumed Zero Hedging Cost, Favoring PJM Membership

A significant task associated with RTO membership is hedging price risk through market tools such as PJM's ARRs and FTRs. Over the long term, such hedging activities should not

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[38] PJM Independent Market Monitor, "Analysis of the 2023/2024 RPM [Reliability Pricing Model] Base Residual Auction" at 1 (Oct. 28, 2022), available at https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf.
[39] *Id.* at 2 (emphasis added).
[40] *Id.*
[41] *Id.* at 4.

result in persistent costs or benefits, but the cost of conducting the hedging activity, like any market participation, is greater than zero. That notwithstanding, the Companies assumed zero cost associated with PJM hedging activities, an assumption favorable to PJM membership scenarios.

Likewise, the Companies assumed a relatively modest allocation of transmission expense in PJM. As increasing amounts of renewable energy come online, increasing amounts of transmission expenditures will likely be necessary to interconnect those resources and bring the energy to market. Some portion of such costs will likely be socialized through PJM's RTEP process. The Companies did not attempt to account for such additional costs, again tending to favor PJM membership scenarios.

As a partial counterbalance, the Companies also did not include in the standalone scenario possible transmission cost sharing in the SERTP region for FERC Order 1000 compliance because such future costs, if any, are unknown at this time. The Companies do not anticipate they will be comparable to the PJM Transmission Expansion Cost values included in this analysis.

In sum, on the whole the Companies made assumptions in their quantitative analysis that tended to favor PJM membership.

But perhaps the most significant assumption the Companies made in their analysis that favored PJM—one that may not be entirely supportable given the reliability and market design concerns discussed above—is that PJM would be able to serve the energy needs of the Companies' customers when called upon to do so, and could do so even if the Companies carried less reserve capacity in accordance with PJM's market rules. Providing customers reliable and low-cost service is vital, and it is unclear that PJM membership would be consistent with either part of that goal, at least at this time.

4.5 Transmission System and Service Considerations

If the Companies joined PJM, functional control of the transmission system would transfer to PJM, including responsibility for system planning and real-time operations. The LG&E and KU transmission system reliably serves customers via existing planning and operations processes today; joining PJM would not immediately transform, improve, or decrease the physical capacity and capability of the transmission system. For this reason, the Companies assumed that transmission customers will continue to receive reliable service from the transmission system in the near term under standalone or RTO-member operations. It is unknown what, if any, changes in transmission service might occur under PJM in the long term.

4.6 PJM Membership Is Not a “Now or Never” Opportunity

It is in RTOs’ interest to welcome new load-serving members, which supply additional markets for the energy and capacity RTOs’ members desire to sell. Moreover, the Companies are unaware of any regulatory obstacle to future RTO membership if the Companies do not pursue it now. Therefore, it is reasonable to assume the Companies could obtain PJM (or other RTO) membership at any time.

It is equally reasonable to assume—based in large part on the Companies’ own experience—that exiting an RTO would be costly and time-consuming, if possible at all. It took years of proceedings before the Commission and FERC for the Companies to exit MISO in the early 2000s; it is not at all clear the Companies could exit an RTO again.

Therefore, because of the difficulty and low likelihood of exiting an RTO, remaining outside an RTO until the net benefits of RTO membership appear to be both durable and reasonably likely across broad range of future scenarios is the most prudent strategy for the Companies and their customers.

4.7 Guidehouse’s Standalone Capacity Expansion Plan Would Position the Companies Well for Future PJM Membership

One of the most interesting results of Guidehouse’s assistance with the Companies’ analysis is that the near and medium term capacity expansion plans Guidehouse’s model created for the Companies are very similar. Using Power System Optimizer, a different capacity expansion modeling tool than the Companies have previously used, Guidehouse produced standalone and RTO-member capacity plans, both of which add two NGCC units with a total capacity of almost 1,000 MW, 400 MW or more of simple-cycle CT capacity, and 750 MW of solar capacity by 2034. This suggests that pursuing a capacity expansion plan for the Companies that included both NGCC and solar capacity in the near and medium term would result in a “no regrets” outcome if PJM membership appeared favorable in future analyses in the next 10 to 15 years. This result further supports taking a wait-and-see approach to RTO membership at this time.

5 Conclusion

In thoroughly reviewing numerous reports and assessments of RTO reliability from NERC and other sources, including the RTOs themselves, the Companies developed their current view that the uncertainties about the future state of RTOs are not mitigated by the potential energy or capacity market benefits demonstrated in the modeled scenarios. The more expansive modeling of all market parties provides additional data for PJM and illustrates the complexity and input sensitivity of such modeling. At this time, given the lack of clarity regarding future RTO market rules and reliability concerns, the Companies do not believe it is in the best interest of their customers to join an RTO. This could change in the future. The Companies will conduct another RTO Membership Analysis in 2023 and assess how any developments of CO_2 or other regulations and updated RTO market rules may affect reliability and provide more certainty about the potential customer benefits of RTO membership.

Appendix 1 Cost Analyses

The following table shows the cost and benefit components of the Companies being a PJM member for each case evaluated.

PJM Membership Cost Analysis - Case 1: Mid Fuel; No CO2 Reductions Regulations ($M)

Costs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Admin Fee Cost	-19.2	-19.6	-20.5	-21.0	-21.3	-21.6	-22.1	-22.5	-22.9	-23.3	-23.8	-24.4	-24.8	-25.3	-25.8	-26.4
PJM Energy Uplift (BOR) Cost	-5.0	-5.0	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1
PJM Transmission Expansion Cost	-20.5	-20.0	-19.6	-19.1	-18.7	-18.2	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8
LG&E/KU Internal Implementation	-0.8	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.5
LG&E/KU Lost Transmission Revenue	-3.0	-3.9	-3.2	-3.7	-4.7	-4.7	-5.1	-4.4	-4.6	-4.3	-3.8	-4.1	-6.7	-6.4	-5.7	-8.6
LG&E/KU Lost Joint Party Settlement Revenue	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9	-1.9	-1.9	-2.0	-2.0
	-49.9	**-50.8**	**-50.7**	**-51.3**	**-52.1**	**-52.0**	**-52.3**	**-52.2**	**-52.7**	**-52.9**	**-52.9**	**-53.8**	**-56.8**	**-57.1**	**-56.9**	**-60.5**

Benefits	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Energy Market Benefits/(Costs)	2.5	11.2	-8.8	37.6	-120.7	-96.7	-122.8	-119.9	-116.9	17.3	-95.4	-184.9	-146.6	-150.7	-61.6	-112.8
PJM Capacity Market Benefits/(Costs)	0.1	0.1	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided Capacity Savings	0.0	0.0	15.6	-0.2	73.2	73.3	71.7	70.1	68.7	-28.7	18.0	157.1	124.5	151.6	67.0	277.7
Avoided Fees (FERC, TVA RC, ITO, TEE)	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.8	7.9	7.9	7.9
LKE Elimination of De-Pancaking	21.6	22.2	12.7	13.1	4.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	31.2	**40.6**	**26.8**	**57.8**	**-35.5**	**-15.4**	**-43.0**	**-41.6**	**-40.0**	**-3.2**	**-69.2**	**-19.5**	**-13.8**	**9.3**	**13.8**	**173.3**

Net Benefits/(Costs)	**-18.6**	**-10.2**	**-24.0**	**6.5**	**-87.6**	**-67.4**	**-95.3**	**-93.8**	**-92.7**	**-56.1**	**-122.1**	**-73.3**	**-70.6**	**-47.8**	**-43.2**	**112.8**

PJM Membership Cost Analysis - Case 2: Mid Fuel; With CO2 Reductions Regulations ($M)

Costs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Admin Fee Cost	-19.2	-19.6	-20.5	-21.0	-21.3	-21.6	-22.1	-22.5	-22.9	-23.3	-23.8	-24.4	-24.8	-25.3	-25.8	-26.4
PJM Energy Uplift (BOR) Cost	-5.0	-5.0	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1
PJM Transmission Expansion Cost	-20.5	-20.0	-19.6	-19.1	-18.7	-18.2	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8
LG&E/KU Internal Implementation	-0.8	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.5
LG&E/KU Lost Transmission Revenue	-3.0	-3.9	-3.2	-3.7	-4.7	-4.7	-5.1	-4.4	-4.6	-4.3	-3.8	-4.1	-6.7	-6.4	-5.7	-8.6
LG&E/KU Lost Joint Party Settlement Revenue	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9	-1.9	-1.9	-2.0	-2.0
	-49.9	**-50.8**	**-50.7**	**-51.3**	**-52.1**	**-52.0**	**-52.3**	**-52.2**	**-52.7**	**-52.9**	**-52.9**	**-53.8**	**-56.8**	**-57.1**	**-56.9**	**-60.5**

Benefits	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Energy Market Benefits/(Costs)	6.8	-2.0	-22.9	29.3	-222.4	-222.5	-239.9	-250.3	-263.7	53.4	-188.3	-350.1	-228.4	-227.0	-72.9	-149.1
PJM Capacity Market Benefits/(Costs)	0.1	0.1	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided Capacity Savings	0.0	0.0	15.6	-0.2	73.2	73.3	71.7	70.1	68.7	-28.7	18.0	157.1	124.5	151.6	67.0	277.7
Avoided Fees (FERC, TVA RC, ITO, TEE)	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.8	7.9	7.9	7.9
LKE Elimination of De-Pancaking	21.6	22.2	12.7	13.1	4.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	35.5	**27.3**	**12.7**	**49.4**	**-137.3**	**-141.2**	**-160.1**	**-172.1**	**-186.8**	**32.9**	**-162.1**	**-184.7**	**-95.7**	**-67.1**	**2.6**	**137.0**

Net Benefits/(Costs)	**-14.4**	**-23.5**	**-38.1**	**-1.8**	**-189.4**	**-193.3**	**-212.4**	**-224.2**	**-239.5**	**-20.0**	**-215.0**	**-238.5**	**-152.5**	**-124.2**	**-54.4**	**76.5**

PJM Membership Cost Analysis - Case 3: High Fuel; No CO2 Reductions Regulations ($M)

Costs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Admin Fee Cost	-19.2	-19.6	-20.5	-21.0	-21.3	-21.6	-22.1	-22.5	-22.9	-23.3	-23.8	-24.4	-24.8	-25.3	-25.8	-26.4
PJM Energy Uplift (BOR) Cost	-5.0	-5.0	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1
PJM Transmission Expansion Cost	-20.5	-20.0	-19.6	-19.1	-18.7	-18.2	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8
LG&E/KU Internal Implementation	-0.8	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.5
LG&E/KU Lost Transmission Revenue	-3.0	-3.9	-3.2	-3.7	-4.7	-4.7	-5.1	-4.4	-4.6	-4.3	-3.8	-4.1	-6.7	-6.4	-5.7	-8.6
LG&E/KU Lost Joint Party Settlement Revenue	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9	-1.9	-1.9	-2.0	-2.0
	-49.9	**-50.8**	**-50.7**	**-51.3**	**-52.1**	**-52.0**	**-52.3**	**-52.2**	**-52.7**	**-52.9**	**-52.9**	**-53.8**	**-56.8**	**-57.1**	**-56.9**	**-60.5**

Benefits	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Energy Market Benefits/(Costs)	4.0	-6.8	-17.2	-24.0	-261.0	-272.9	-291.7	-304.6	-300.7	34.7	-216.3	-366.3	-231.7	-249.2	-68.4	-126.0
PJM Capacity Market Benefits/(Costs)	0.1	0.1	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided Capacity Savings	0.0	0.0	15.6	-0.2	73.2	73.3	71.7	70.1	68.7	-28.7	18.0	157.1	124.5	151.6	67.0	277.7
Avoided Fees (FERC, TVA RC, ITO, TEE)	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.8	7.9	7.9	7.9
LKE Elimination of De-Pancaking	21.6	22.2	12.7	13.1	4.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	32.7	**22.5**	**18.3**	**-3.9**	**-175.8**	**-191.6**	**-211.9**	**-226.3**	**-223.8**	**14.2**	**-190.1**	**-200.9**	**-98.9**	**-89.2**	**7.0**	**160.2**

Net Benefits/(Costs)	**-17.2**	**-28.3**	**-32.4**	**-55.1**	**-227.9**	**-243.6**	**-264.3**	**-278.5**	**-276.5**	**-38.7**	**-243.0**	**-254.7**	**-155.7**	**-146.3**	**-49.9**	**99.7**

PJM Membership Cost Analysis - Case 4: High Fuel; With CO2 Reductions Regulations ($M)

Costs	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Admin Fee Cost	-19.2	-19.6	-20.5	-21.0	-21.3	-21.6	-22.1	-22.5	-22.9	-23.3	-23.8	-24.4	-24.8	-25.3	-25.8	-26.4
PJM Energy Uplift (BOR) Cost	-5.0	-5.0	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1	-5.1
PJM Transmission Expansion Cost	-20.5	-20.0	-19.6	-19.1	-18.7	-18.2	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8	-17.8
LG&E/KU Internal Implementation	-0.8	-0.8	-0.8	-0.7	-0.7	-0.7	-0.7	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-0.5	-0.5
LG&E/KU Lost Transmission Revenue	-3.0	-3.9	-3.2	-3.7	-4.7	-4.7	-5.1	-4.4	-4.6	-4.3	-3.8	-4.1	-6.7	-6.4	-5.7	-8.6
LG&E/KU Lost Joint Party Settlement Revenue	-1.5	-1.5	-1.6	-1.6	-1.6	-1.7	-1.7	-1.7	-1.8	-1.8	-1.8	-1.9	-1.9	-1.9	-2.0	-2.0
	-49.9	**-50.8**	**-50.7**	**-51.3**	**-52.1**	**-52.0**	**-52.3**	**-52.2**	**-52.7**	**-52.9**	**-52.9**	**-53.8**	**-56.8**	**-57.1**	**-56.9**	**-60.5**

Benefits	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
PJM Energy Market Benefits/(Costs)	128.5	148.9	154.0	137.6	-254.0	-263.5	-302.4	-325.2	-276.4	104.7	-283.5	-522.1	-316.0	-323.3	-83.7	-192.6
PJM Capacity Market Benefits/(Costs)	0.1	0.1	0.03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Avoided Capacity Savings	0.0	0.0	15.6	-0.2	73.2	73.3	71.7	70.1	68.7	-28.7	18.0	157.1	124.5	151.6	67.0	277.7
Avoided Fees (FERC, TVA RC, ITO, TEE)	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.8	7.9	7.9	7.9
LKE Elimination of De-Pancaking	21.6	22.2	12.7	13.1	4.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	157.2	**178.3**	**189.6**	**157.8**	**-168.8**	**-182.2**	**-222.6**	**-247.0**	**-199.5**	**84.3**	**-257.3**	**-356.7**	**-183.2**	**-163.4**	**-8.3**	**93.5**

Net Benefits/(Costs)	**107.3**	**127.5**	**138.8**	**106.5**	**-220.9**	**-234.2**	**-275.0**	**-299.1**	**-252.2**	**31.4**	**-310.2**	**-410.5**	**-240.0**	**-220.5**	**-65.2**	**33.1**

Appendix 2 Modeling Assumptions

Assumed LG&E/KU Unit Retirement Schedule through 2040

	Assumed Retirement Year	Net Summer Capacity (MW)	Cumulative Capacity Assumed to be Retired (MW)
Mill Creek 1	2024	300	300
Haefling 1	2025	12	312
Haefling 2	2025	12	324
Paddy's Run 12	2025	23	347
E W Brown 3	2028	412	759
Mill Creek 2	2028	297	1,056
E W Brown 9	2034	121	1,177
Ghent 1	2034	475	1,652
Ghent 2	2034	485	2,137
E W Brown 8	2035	121	2,258
E W Brown 10	2035	121	2,379
E W Brown 11	2036	121	2,500
Ghent 3	2037	481	2,981
Ghent 4	2037	478	3,459
E W Brown 6	2039	146	3,605
E W Brown 7	2039	146	3,751
Mill Creek 3	2039	391	4,142
Mill Creek 4	2039	477	4,619

National CO_2 Emissions Reductions Regulations

To demonstrate the impact of potential CO_2 emissions reductions regulations, the Companies assumed in some cases a CO_2 reduction pathway that is consistent with an illustrative pathway proposed by the Intergovernmental Panel on Climate Change's ("IPCC") to limit global warming to 1.5 degrees Celsius.[42] The following table approximates this assumed pathway of annual CO_2 reductions from 2010 levels.

Assumed CO_2 Reduction Pathway from 2010 Levels

2025	-19%
2026	-23%
2027	-28%
2028	-32%
2029	-37%
2030	-41%
2031	-44%
2032	-47%
2033	-50%
2034	-53%
2035	-57%
2036	-60%
2037	-63%
2038	-66%
2039	-69%
2040	-72%

[42] IPCC describes its "P3" pathway as "A middle-of-the-road scenario in which societal as well as technological development follows historical patterns. Emissions reductions are mainly achieved by changing the way in which energy and products are produced, and to a lesser degree by reductions in demand." See p. 14 of IPCC's 2018: Summary for Policymakers in: *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels in the context of strengthening response to climate change, sustainable development, and efforts to eradicate poverty* at https://doi.org/10.1017/9781009157940.001.

Expansion Unit Costs

Guidehouse based their assumptions for the capital and operating costs shown in the following two tables on the National Renewable Energy Laboratory's 2022 Annual Technology Baseline.

Generation Expansion Unit Capital Costs (Real 2020 $/kW)

	Solar	Wind	Battery Storage (4 hr.)	Battery Storage (8 hr.)	NGCC	SCCT	Advanced NGCC
2025	982	1,206	1,104	1,968	941	818	4,561
2026	936	1,156	1,057	1,866	934	809	4,561
2027	891	1,106	1,015	1,778	927	798	4,561
2028	846	1,056	968	1,684	921	792	4,561
2029	800	1,006	931	1,601	916	785	4,561
2030	754	956	895	1,525	912	781	4,561
2031	748	946	884	1,507	907	775	4,561
2032	741	937	873	1,487	903	771	4,561
2033	734	927	862	1,468	899	766	4,561
2034	728	918	850	1,449	896	763	4,561
2035	721	908	839	1,430	891	759	4,561
2036	714	899	828	1,411	888	754	4,561
2037	707	889	817	1,392	884	750	4,561
2038	701	879	806	1,373	880	747	4,561
2039	694	870	794	1,354	876	742	4,561
2040	687	860	783	1,335	873	738	4,561

Generation Expansion Unit Fixed Operating & Maintenance Costs (Real 2020 $/kW-yr.)

	Solar	Wind	Battery Storage (4 hr.)	Battery Storage (8 hr.)	NGCC	SCCT	Advanced NGCC
2025	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2026	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2027	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2028	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2029	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2030	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2031	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2032	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2033	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2034	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2035	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2036	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2037	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2038	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2039	18.00	27.52	29.00	29.00	12.26	7.04	25.00
2040	18.00	27.52	29.00	29.00	12.26	7.04	25.00

Inflation

To convert between real and nominal dollars, Guidehouse assumed the following inflation rates.

Annual Inflation

2021	4.3%		2031	2.4%
2022	6.6%		2032	2.3%
2023	1.7%		2033	2.3%
2024	3.5%		2034	2.3%
2025	3.5%		2035	2.3%
2026	3.5%		2036	2.3%
2027	2.8%		2037	2.3%
2028	2.4%		2038	2.3%
2029	2.4%		2039	2.3%
2030	2.4%		2040	2.3%

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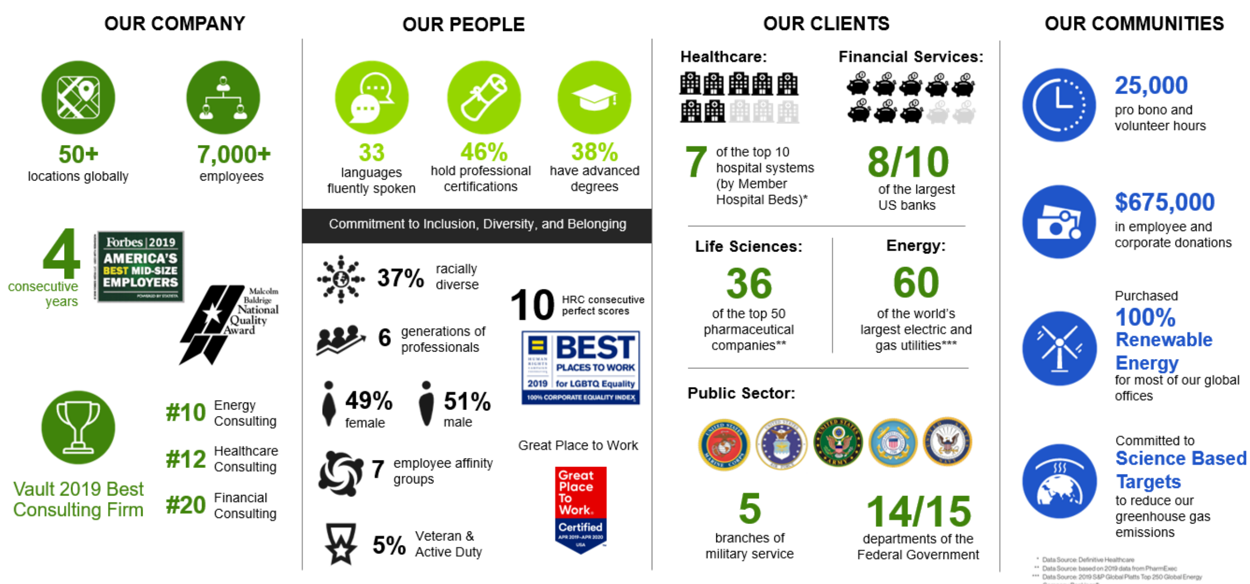

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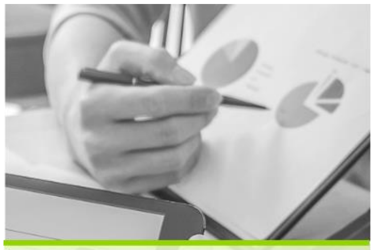

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Energy Markets Analysis

Prepared for:

LG&E KU
PPL companies

Submitted by:
Guidehouse, Inc.
1200 19th Street NW
Suite 700
Washington, DC 20036

202.973.2400
Guidehouse.com

May 2023

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NOTICE

EXECUTIVE SUMMARY

Study Scope and Purpose

LG&E / KU engaged Guidehouse to inform and educate the company regarding the potential costs and benefits of joining PJM. This study simulated two cases: (1) the SA Case in which LG&E / KU remains a standalone balancing authority, and (2) the RTO Case in which LG&E / KU joins PJM.

Both the Status Quo and the RTO cases considered four market outlooks:

- Case 1: A baseline market scenario based on Guidehouse’s Spring 2022 Reference Case and LG&E / KU provided fuel prices
- Case 2: A case in which national CO2 emissions reduction regulations are assumed
- Case 3: High fuel with no additional carbon emission regulations
- Case 4: High fuel with additional carbon emission regulations

The study evaluates the implications of LG&E / KU joining PJM with respect to production costs, import and export volumes, generation, emissions, and capacity prices.

Modeling Approach

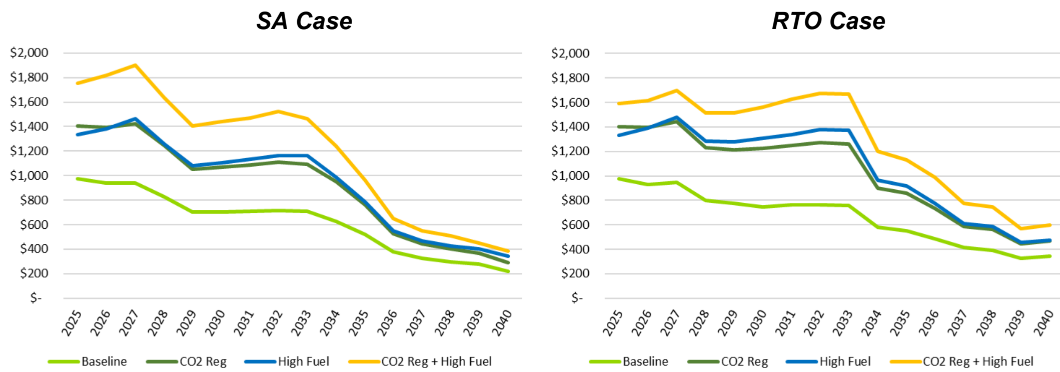
The benefits and costs to LG&E/KU customers of each alternative were evaluated by comparing a business-as-usual or status-quo case to a case in which LG&E / KU joins PJM. Given the complexity of obtaining necessary approvals and preparing for full operational integration for these alternatives, the study uses 2025 as the start year for entry. The benefits and costs are reported in terms of real 2020 dollars over the 2025 to 2040 period.

Results

Adjusted Production Costs

Joining an RTO creates more opportunities for purchases and sales and allows generators to operate more efficiently, resulting in adjusted production cost savings, or dispatch benefits, and are assessed using PSO by comparing the SA Case to a case in which LG&E / KU is part of PJM (the Join PJM case).

Annual Production Costs ($mil)

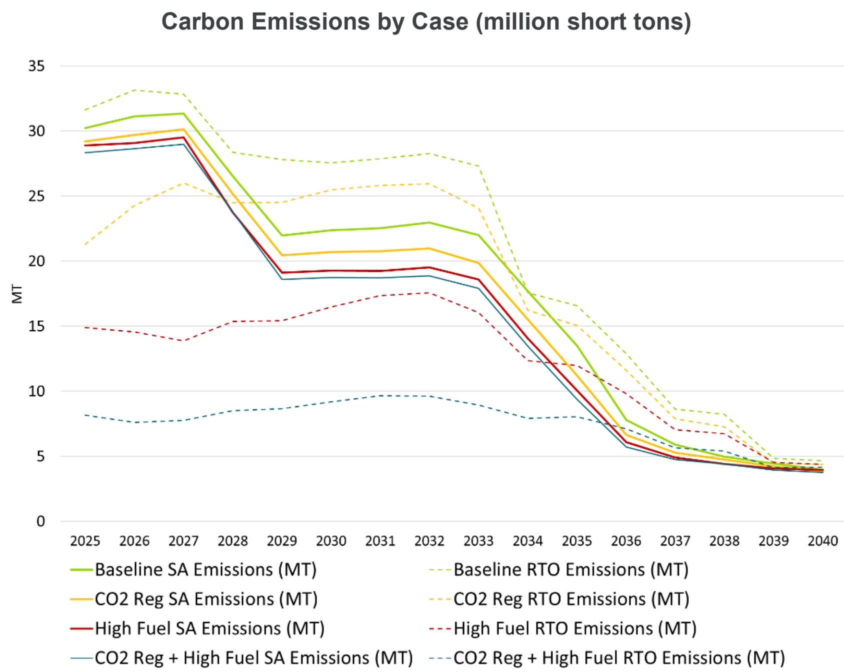


Generation, Imports, and Exports

LG&E / KU's generation is significantly lower in the RTO cases than in the SA cases between 2025-2027 because it is optimal for LG&E / KU to import power to serve its load. LG&E / KU's generation increases and total generation by the end of the forecast period is approximately equal among all cases.

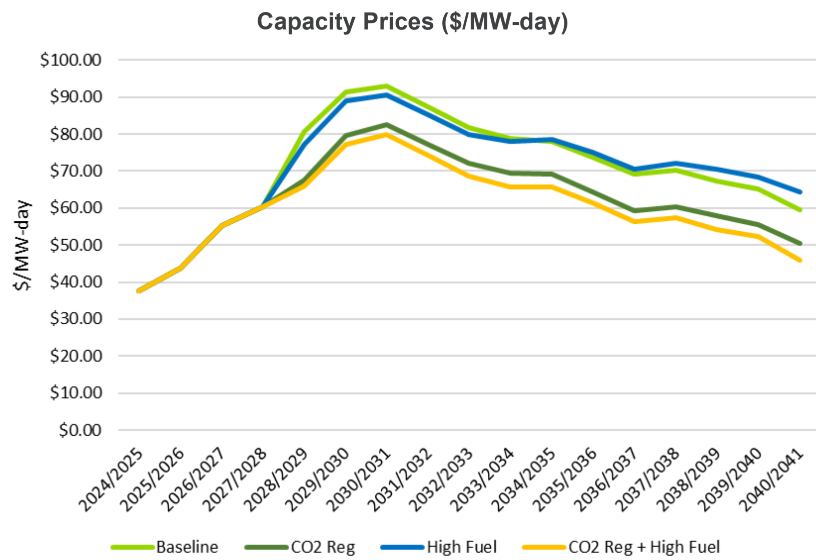
Carbon Emissions

Differences in carbon emissions are most pronounced in the near term and between RTO cases than SA cases, reflecting the differences in generation. In the long-term, total emissions become relatively constant between cases.



Capacity Prices

Generally, capacity prices follow PJM's reserve margins. Short-term RTO capacity prices clear in the \$41/MW-day to \$48/MW-day range, which follows the trend of the 2023/2024 auction and remains depressed. The high fuel prices somewhat affect the results, however the high fuel prices and efficient CC operations largely offset with respect to capacity prices.


Capacity Prices ($/MW-day)
$/MW-day
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
2024/2025
2025/2026
2026/2027
2027/2028
2028/2029
2029/2030
2030/2031
2031/2032
2032/2033
2033/2034
2034/2035
2035/2036
2036/2037
2037/2038
2038/2039
2039/2040
2040/2041
Baseline
CO2 Reg
High Fuel
CO2 Reg + High Fuel

1. PJM MARKET SUMMARY

This section of the report provides a historical overview of the PJM market and trends. Any forecasts that appear in this section are as reported by third parties or the regional transmission organization (RTO) itself and do not necessarily reflect Guidehouse's assumptions.

1.1 History and Market Overview

PJM is an RTO that manages grid operations and wholesale electricity markets for over 65 million people in all or parts of 13 states and the District of Columbia. PJM is composed of approximately 1,095 members, including power generators, transmission owners, electricity distributors, power marketers, and large consumers. PJM dispatches approximately 185,769 MW of generating capacity and has more than 84,236 miles of transmission lines. The region had a 2021 peak demand of 151,680 MW.[1]

An overview of characteristics of the PJM market is provided below in Table 1 and load zones are shown in Figure 1.

Table 1. PJM Market Highlights

Market Feature	Summary of PJM
Footprint	All or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
Customers Served	Approximately 65 million.
Peak Load	Summer peaking system with a 2021 summer peak of 151,680 MW
Installed Capacity	Installed capacity of approximately 185,769 MW. Fuel mix: 26% coal, 46% gas, 17% nuclear, 3% oil, 5% hydro, 1.4% wind, 0.4% solid waste, and 1.1% solar.
Energy Market	Day-ahead market incorporates bilateral contracts and competitive market results. Real-time market calculated every 5 minutes based on actual grid operating conditions.
Congestion Management and Hedging	PJM's board has approved several upgrade projects to increase the west-to-east transfer capability, reduce congestion along the eastern coastline, and allow new and more efficient generation resources to connect to the electric grid. Financial Transmission Rights are available to hedge against the economic effects associated with transmission congestion and provide financial instruments to arbitrage differences between expected and actual day-ahead transmission congestion.

[1] PJM. *State of the Market Report for PJM 2021.*

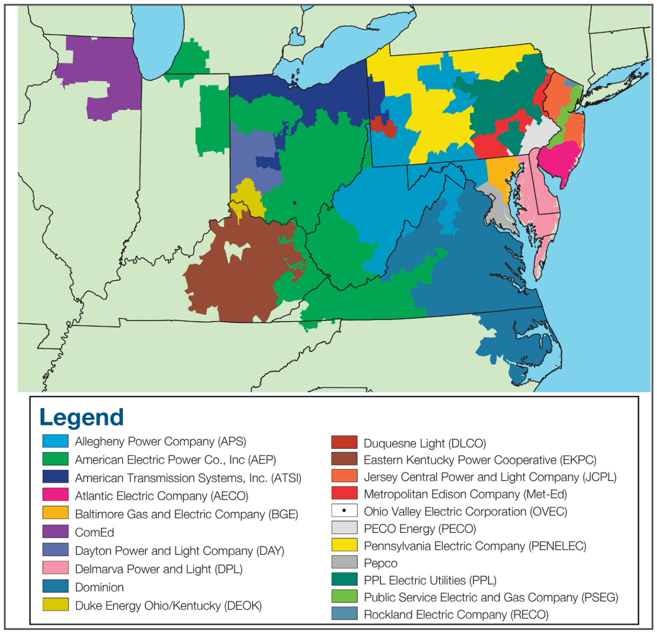
Market Feature	Summary of PJM	
Ancillary Services	Three markets for ancillary services: regulation and reserve markets are optimized with the energy market simultaneously to minimize costs to the grid and are cleared on a real-time basis; day-ahead scheduling reserve market obtains supplemental 30-minute reserves that are potentially necessary to resolve unanticipated system conditions throughout the actual operating day.	
Capacity Market	In PJM's Reliability Pricing Model (RPM), auctions are held 3 years in advance of delivery to procure enough capacity to meet estimated demand, plus a targeted 14.8% installed reserve margin. The cost of the winning bids is allocated among load-serving entities (LSEs).	
Renewable Portfolio Standards[2]	**Delaware:** 40% by 2035 **Illinois:** 50% by 2040 **Maryland:** 50% by 2030 **New Jersey**: 50% by 2030 **Ohio:** 8.5% by 2026 **Virginia:** 100% by 2050	**District of Columbia:** 50% by 2032 **Indiana:** 10% by 2025 (voluntary) **Michigan:** 15% by 2021 **North Carolina:** 12.5% by 2021 **Pennsylvania:** 18% by 2021

[2] PJM. *Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States.*

Market Feature	Summary of PJM
Energy Efficiency Standards	**Delaware:** No mandatory EERS. Voluntary energy savings targets for 2020-2022: 0.7% of total electric sales for electric utilities 0.2% total gas sales for natural gas utilities **Illinois:** Electric: Vary by utility, cumulative reductions of 16% or 21.5% by 2030; incremental annual savings of 1.5% by 2019 for gas utilities **Indiana:** Energy Efficiency Resource Standards repealed in 2014 and replaced in 2015 with measures within the integrated resource plan (IRP) regulations **Maryland:** 0.2% incremental annual savings in 2016 ramping up by 0.2% per year to 2% in 2023 **Michigan:** Annual savings of 1% for electricity and 0.75% for natural gas. Targets terminate in 2021 for non-rate regulated utilities, representing ~10% state load. Financial incentives under PA 342 have spurred utilities to pursue 1.5% annual electric savings. Recent IRPs call for 2% savings for 2021 and beyond **New Jersey:** Standards enacted in 2018 requiring 2% electric and 0.75% gas savings goals by 2023 **North Carolina:** Energy efficiency is eligible for up to 25% of the 2012-2018 targets and at 40% of the 2021 target **Ohio:** State EERS effectively terminated by HB 6 in 2019; once 17.5% cumulative energy savings is reached (anticipated in 2020), EE program is scheduled to end at end of 2020. **Pennsylvania:** Targets vary by utility and are equivalent to about 0.8% incremental annual savings through 2020 **Virginia:** Dominion Energy required to achieve 1.25% energy savings in 2022 relative to a 2019 baseline and increases each year to 5% in 2025. Appalachian Power required to achieve 0.5% in 2022, relative to a 2019 baseline and increases each year to 2% in 2025.

Sources: Guidehouse, American Council for an Energy-Efficient Economy, DSIREUSA.org, PJM

Figure 1. PJM Load Zones



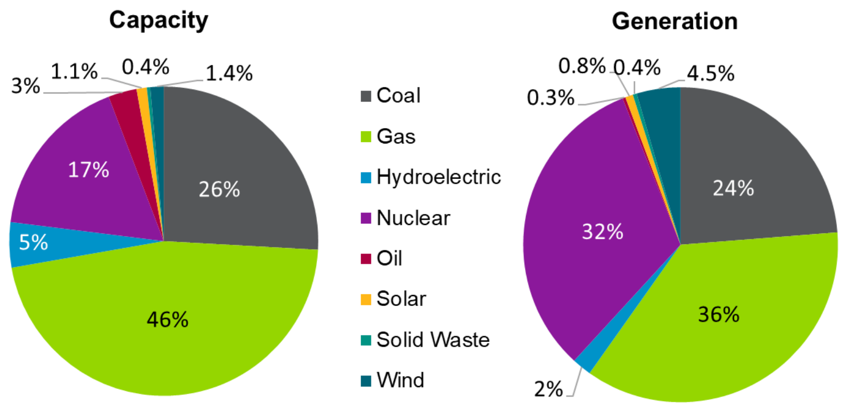
Source: PJM

1.2 Supply

1.2.1 Current Mix

In PJM, independent power producers and utilities own approximately 72% and 23% of generation capacity, respectively. The generation is widely held in PJM, but the largest generation owners are the integrated utilities (e.g., AEP, Dominion, Exelon). PJM's generation portfolio relies on coal, gas combined cycle (CC), and nuclear resources for baseload energy. Peaking capacity is primarily met by natural gas as seen in Figure 2. Natural gas-fired power plants, which are generally located in eastern PJM and near metropolitan areas, accounted for over 46% of PJM's installed capacity and about 36% of energy production so far in 2022. Nuclear generation, on the other hand, accounted for 17% of capacity but provided 32% of generation. Coal generation, which is mainly located in Western PJM, accounted for 26% of total installed capacity and 24% of energy production.

Figure 2. 2021 Installed Capacity and Generation by Fuel Type



Source: Guidehouse (Data from 2022 PJM Quarterly State of the Market Report Q1)

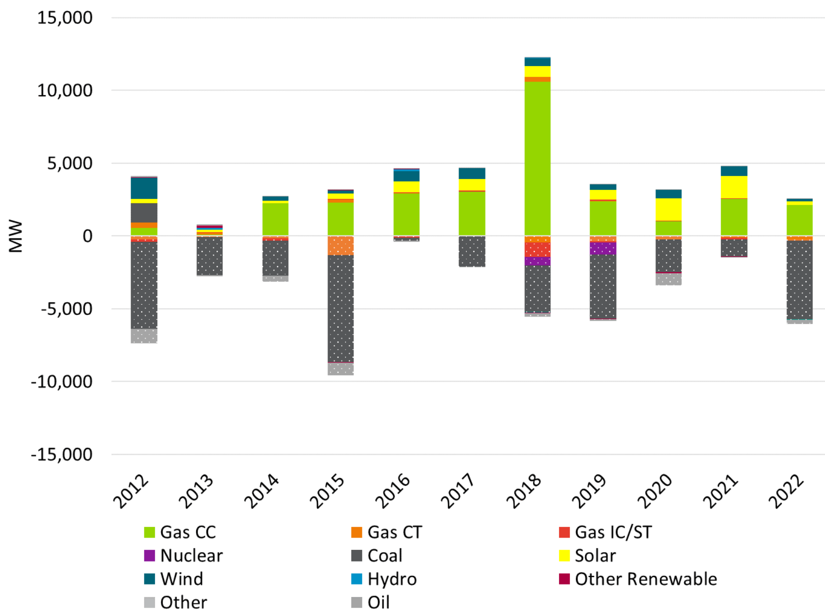
Over 70% of PJM's current coal fleet is over 40 years old, just under 90% of installed natural gas energy capacity was built after 1990. New natural gas capacity is comprised of CC units and CCGT peakers. PJM's entire wind and solar fleet was built after 1990.

1.2.2 Generation Addition and Retirement Trends

Figure 3 shows recent additions and retirements to PJM's installed capacity. Most of the capacity brought online between 2012 and 2022 consisted of natural gas CCs as gas prices continue to fall. Environmental regulations resulted in a significant number of recent and pending coal retirements. Approximately 39 GW of generation has retired from 2011 to 2021, of which 29.8 GW were coal assets. Continued coal retirements are expected over the next decade due to poor economics for coal plants, primarily driven by environmental regulations. For example, the recently passed VCEA requires Dominion and APCo to retire all coal-fired generating units in Virginia by 2025.[3]

[3] With the exception of any coal-fired electric generating units which are jointly owned with an electric co-op or are owned and operated by Dominion in the coalfield region of Virginia that co-fire with biomass.

Figure 3. Generation Capacity Additions and Retirements Since 2012[4]



Source: Guidehouse (Data from Energy Velocity, retrieved July 2022)

1.2.3 Related Policies

1.2.3.1 Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are policies that require suppliers or load-serving entities within the state to obtain a minimum percentage of their sales from certain renewable energy resources by a specified date or face penalties. RPS currently exist in places in 10 states and the District of Columbia within PJM's territory, as shown in Table 2. However, the majority of some of these states fall within the service territories of other ISO/RTOs. The states with RPS policies that currently impact PJM are Delaware, Maryland, New Jersey, Virginia, and the District of Columbia.

Table 2. PJM RPS Requirements by State

State	PJM (Tier 1 Standards)	Carve-outs or specified targets (if applicable)
Delaware	25% by 2025	3.5% solar PV by 2025
Illinois	25% by 2025	6% solar PV
Maryland	52.5% by 2030 (Increased RPS from 23.2% in 2019)	14.5% solar target

[4] 2022 additions and retirements are current as of July 2022

New Jersey	52.5% by 2030 (Increased RPS from 20.975% in 2018)	5.1% solar carve-out by 2022
North Carolina	12.5% by 2021	0.2% Solar by 2021
Pennsylvania	18% by 2021	0.5% solar by 2021
District of Columbia	100% renewable energy by 2032	5.5% solar by 2032
Indiana	10% by 2025 (voluntary)	-
Michigan	15% by 2021	-
Ohio	8.5% by 2026	-
Virginia	100% by 2050	-

Source: Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States

In 2019, the passage of HB 6 in Ohio effectively repealed the state's RPS, with the solar requirement phasing to 0% by 2027. The bill replaced the RPS with a program which will subsidize two nuclear and two coal plants. The bill will provide $1 billion in funding for both Davis-Besse and the Perry Nuclear Plants, as well as provide funding to two Ohio Valley Electric Corporation coal plants through 2027.

Ohio was under scrutiny in July 2020 as a bribery scandal was uncovered surrounding the proposal to repeal House Bill 6 (HB 6). Allegations arouse that FirstEnergy paid approximately $60 million to Generation Now, an organization affiliated and controlled by then Speaker of the Ohio House of Representatives Larry Householder. Federal agents quickly arrested Householder on charges of organizing a years-long criminal conspiracy which offered billions of taxpayer dollars to keep bankrupt FirstEnergy from closing its nuclear plants.

As of July 2022, HB6 remains in place. Supporters say the bill saves money on electric bills due to cuts to the clean energy mandates. Opponents argue the RPS was a cost benefit to the bottom line of electric bills. An additional charge of $2.35 a month appeared on ratepayer bills beginning January 2021.

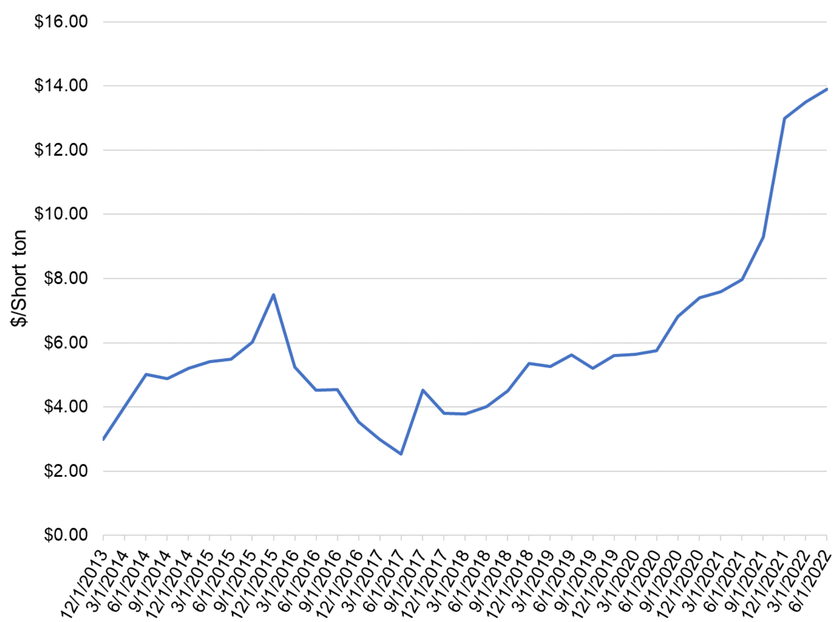
1.2.3.2 Regional Greenhouse Gas Initiative

Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia are members of the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program to curb CO_2 emissions. Virginia passed the Virginia Clean Energy Economy Act of 2020 (SB 851), which approved the state joining RGGI, with participation beginning January 1, 2021.

In 2019, Pennsylvania Gov. Wolf (D) issued an Executive Order directing the Pennsylvania Department of Environmental Protection (DEP) to propose rules to significantly reduce carbon emissions and join RGGI. In September 2020, the Pennsylvania Environmental Quality Board (EQB) voted to move forward with the state joining RGGI in 2022. However, in April 2021, the Pennsylvania Senate passed Senate Bill 119 requiring legislative approval for the state to enter into a carbon pricing program like RGGI. Pennsylvania continues to host stakeholder meetings as it moves forward with the approval process. In a similar vein, North Carolina's Environmental Management Commission voted, in July 2021, to begin the rule-making process in order to join RGGI. Two days later, the North Carolina House passed House Bill 951 which also stipulates legislative approval for joining RGGI. Guidehouse's Fall 2021 Reference Case does not currently include Pennsylvania nor North Carolina in its RGGI price forecast; however, Guidehouse continues to monitor regulatory and legislative developments.

There have been 56 RGGI auctions held to date; the clearing price for the June 2022 auction was \$13.90/ton, which was higher than the March 2022 clearing price of \$13.50/ton, and significantly higher than the clearing price of \$7.97/ton in June 2021. This marked increase in price may be in response to uncertainty about the future of a few participants in RGGI (namely Virginia, North Carolina, and Pennsylvania), as well as the retirement of Indian Point and the end of a COVID lull. The combination of these factors may have led to some confusion in the market and subsequently applied an upward pressure on prices. As seen in Figure 4, prices dropped sharply in 2017 mainly due to relatively low demand for RGGI allowances but began to rebound in subsequent years as interest from compliance entities increased. An important aspect of the RGGI auction is the cost containment reserve (CCR), which enables a fixed quantity of allowances to be held in reserve and made available if allowance prices are to exceed a predefined price level, or price ceiling. In 2021, the CCR price trigger was \$13/ton, so as a result, 3,919,482 allowances were sold in the December 2021 auction. Before that auction, the CCR had only been used twice, in the 23rd and 29th auctions. The CCR price trigger increases by 7% per year from the \$13/ton 2021 level.

Figure 4. RGGI Clearing Price Auction Results (\$/Short ton)



Source: RGGI

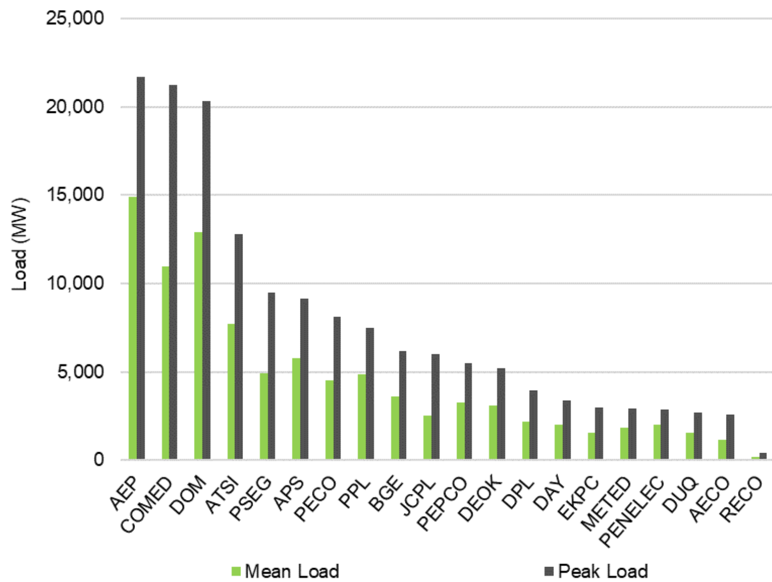
The economic impact of RGGI on affected fossil fuel generators will be the added cost of the CO_2 allowances to the energy production (bid) cost of these generators. The estimated impacts of the RGGI program on generation resources have been minimal to date, and the cost to consumers has been offset by investment of funds raised by RGGI's in-state energy efficiency programs. The overall cost to consumers could change as the emissions cap is lowered.

1.3 Demand

1.3.1 Market Players

The 2022 mean and peak load for PJM's 20 load zones are shown below in Figure 5. AEP has the highest zonal peak load and average load, followed by ComEd and Dominion (DOM).

Figure 5. 2021 Average and Peak Demand by Load Zone (MW)



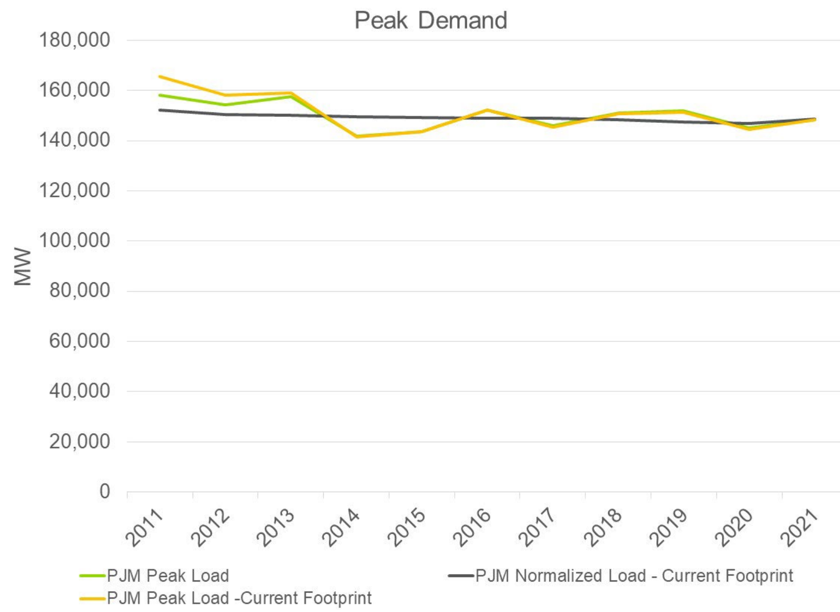
Source: Guidehouse (Data from Energy Velocity, retrieved July 2022)

The majority of demand is still served by incumbent utilities. Investor-owned utilities serve about two-thirds of demand, and cooperatives and municipals serve about 7% of demand, with the balance being served by deregulated providers and direct-use customers. About two-thirds of the states within PJM have retail competition (New Jersey, Maryland, the District of Columbia, Delaware, Pennsylvania, Ohio, Michigan, and Illinois), with the remaining states utilizing only regulated service providers. Virginia suspended deregulation in 2007, but loads that average more than 5 MW annually may still choose a deregulated provider.

1.3.2 Historical Demand

Figure 6 shows historical peak demand in PJM, including coincident peak, weather normalized and unrestricted peak. Summer coincident peak decreased significantly from 148,228 MW in 2019 to 141,449 in 2020, driven by the COVID-19 pandemic.

Figure 6. PJM Historical Peak Demand



Source: Guidehouse (data from PJM State of the Market Reports and Energy Velocity, retrieved December 2021)

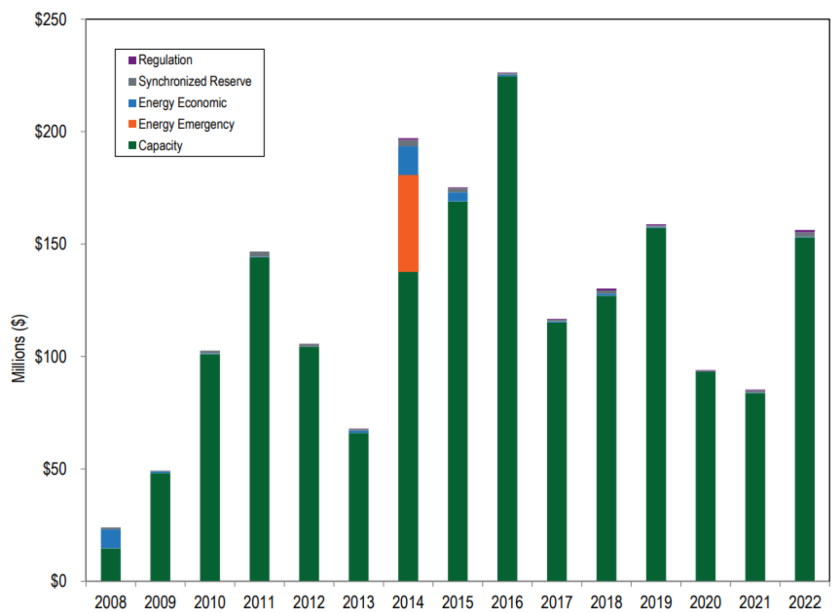
Flat load growth has been driven by energy efficiency in the recent years. PJM's 2022 Load Forecast Report projects 0.4% annual average growth for peak load and 0.8% annual average growth for net energy over the next 10 years for the whole RTO. [5]

[5] PJM. *Load Forecast Report 2022*

1.3.3 Demand Response and Energy Efficiency Programs

PJM includes energy savings in its load forecast data reporting. As a result, Guidehouse follows this methodology and the load forecast is not impacted by energy efficiency. In PJM, the implementation of the Reliability Pricing Model (RPM) facilitated significant growth in demand-side participation in the capacity market. Demand response (DR) can bid into the energy market, curtail for emergency conditions only, or both. DR resources are generally used for emergency curtailment during periods of extremely high load. The majority DR revenue streams comes from capacity payments, as seen in Figure 7.

Figure 7. PJM Historic DR Revenue by Market[6]

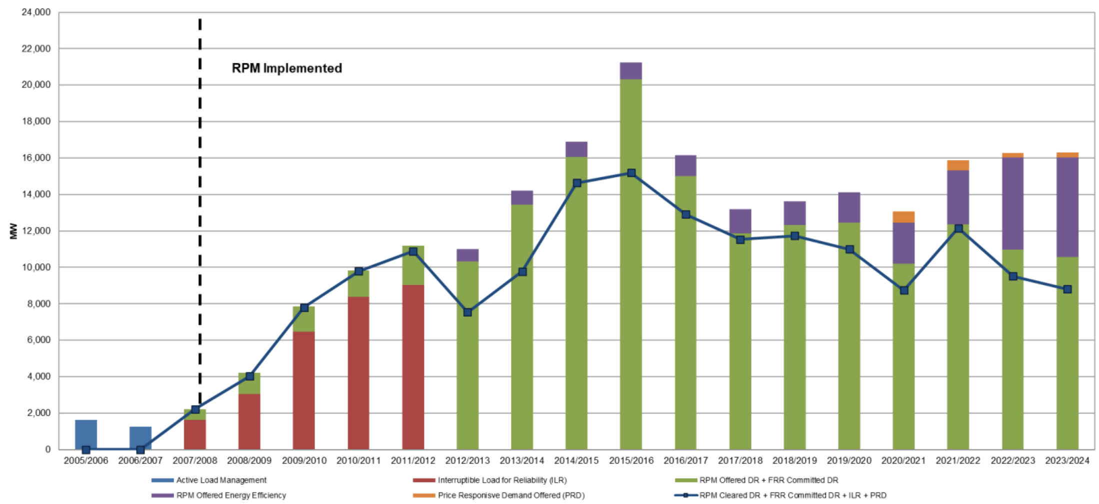


Source: PJM State of the Market Report 2022 Q1

[6] *Capacity net revenue inclusive of capacity credits and charges*
PJM assumes capacity value at $50 MW-day (PJM does not know the value of capacity credits in the forward market prior to RPM; only a portion of capacity was purchased through the daily capacity market at the time).

Figure 8 indicates historical and forecast DR and energy efficiency capability by year. After years of steady increases, DR participation has decreased in the past three auctions due to recent caps on limited and extended summer DR, and mandates that DR providers offer increased assurance that they will be able to deliver the demand reductions promised in their offers.

Figure 8. Demand-Side Participation in Capacity Market



Source: PJM 2023/2024 RPM Base Residual Auction Results Report

PJM also operates an Economic Load Response Program (ELRP), which allows commercial and industrial customers to voluntarily reduce load during times when their bid exceeds the locational energy market price at that time. The estimated reduction in peak demand and energy consumption resulting from the ELRP program is shown in Table 3.

Table 3. PJM Economic Load Response Program[7]

Year	Average Registered Resources (MW)	Sum of Peak Reductions (MW)
2022*	2,390	44
2021	1,927	921
2020	2,040	196
2019	2,855	830
2018	2,606	758
2017	2,000	1,217
2016	2,547	1,451
2015	2,788	1,858
2014	2,732	1,739
2013	2,364	1,486
2012	2,175	1,942
2011	2,382	840

Source: PJM State of the Market, Q1 2022

Peak reductions from the ELRP increased significantly from 2020 to 2021, going from a paltry 196 MW in 2020 to 921 MW. 2021 is a return to comparable levels like those seen before the COVID-19 Pandemic. The first nine months of 2020 had the lowest economic load response since 2010, driven by reduced demand due to COVID. Guidehouse expects 2022 peak reductions to be similar to those seen in 2021.

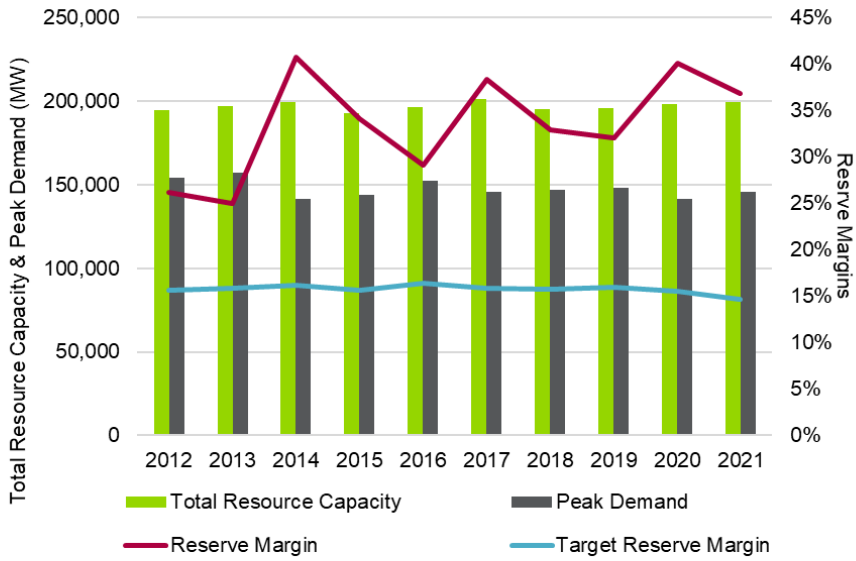
1.4 Demand and Supply Balance

The demand and supply balance for PJM is shown in Figure 9. PJM currently has an installed reserve margin (IRM) target of 14.8% and historically has been well overbuilt with reserve margins of over 30%. The excess generation capacity is caused in large part by slow demand growth in recent years, growth of new natural gas generation and renewables relative to retirements, and the growth of demand-side resources. On a localized basis, resources are more concentrated in western PJM, while many of the load centers are further east.

However, expansion of transmission and generation in eastern parts of PJM is space-constrained due to higher population densities. From a reliability perspective, these areas are expected to continue to rely on capacity from other regions. This is enabled by a transmission system that allows the transfer of energy from the midwestern and western portions of PJM into the east. However, transmission requirements could change over time, depending on where coal retirements and replacement generation are ultimately located.

[7] *2022 values represent the first three months of 2022 through March*

Figure 9. PJM Demand and Supply Balance



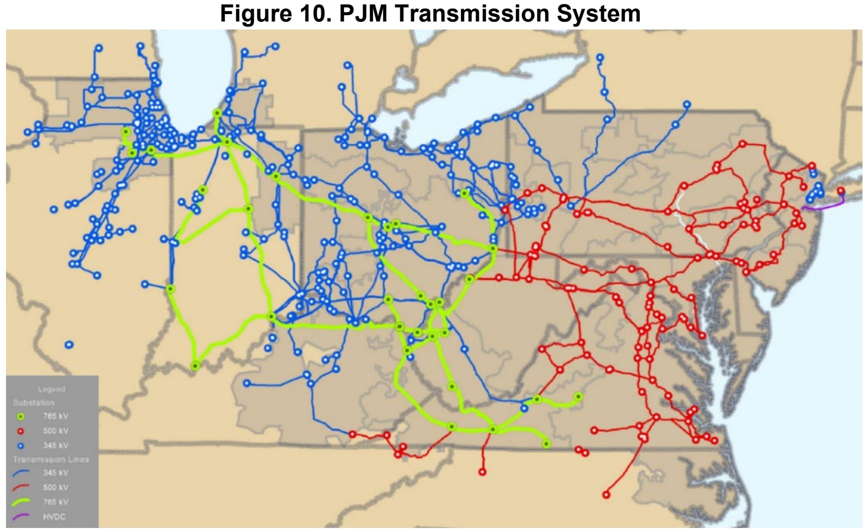
Source: Guidehouse (data from PJM State of the Market Reports)

1.5 Transmission

1.5.1 Existing Transmission System

The existing PJM transmission system contains more than 85,000 miles of transmission lines and 6,650 substations, interconnecting with more than 185,769 MW of power generation, as shown in Figure 10.

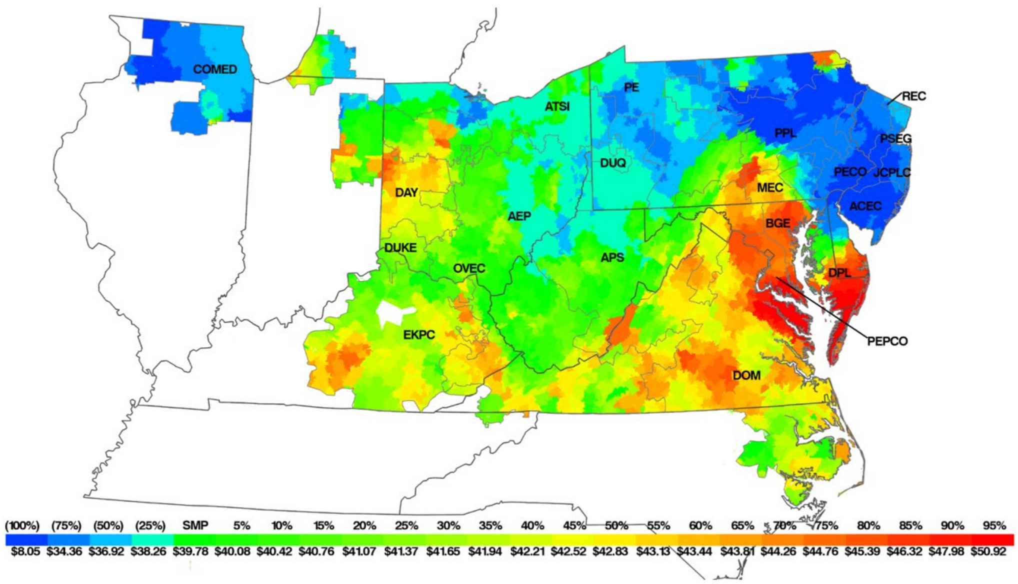
Figure 10. PJM Transmission System



Source: PJM 2021 RTEP

Transmission capacity between the eastern and western parts of PJM is constrained at several points, the most significant being the Eastern Interface connecting PJM East to the rest of the RTO. During off-peak times when the system is not constrained, electricity market prices in PJM East are often set by imports of thermal from the western parts of PJM. However, during on-peak times when imports are limited by the capacity of the Eastern Interface, more expensive local peaking units often set electricity market prices in PJM East. As a result, on-peak prices are often higher in PJM East than in the rest of PJM. PJM estimates that this congestion has cost between \$0.5B to \$2.05B per year since 2008.[8]

Figure 11. Real-Time Load Weighted LMPs 2021



Source: PJM State of the Market 2021

Transmission expansion in PJM East is limited by the challenges associated with building near population centers. New transmission and generation developments require ample space and accessibility-scarce resources in this part of the country. This makes resources within the constrained area best-positioned to serve load during on-peak hours.

1.5.2 Planned Transmission Projects

PJM bulk electric system (BES) baseline and networks upgrade projects are implemented to ensure compliance with PJM and NERC standards. The Regional Transmission Expansion Plan (RTEP) process identifies transmission system addition and improvement projects needed to serve customers. These projects include power line enhancements that increase line stability and reliability, new lines, transformers, and existing line up rates, and bus configurations to accommodate increased power flow. In 2021, the PJM

[8] PJM State of the Market 2021

Board approved 118 new baseline projects for an estimated $920M. Of the total amount approved for transmission upgrades, the majority ($478M) was driven by transmission owner needs, namely from AEP, Dominion and AMPT. The next largest drivers for transmission project approval were baseline deliverability and generator deactivation.

1.6 Markets

1.6.1 Capacity Market

PJM has operated the Reliability Pricing Model (RPM) capacity market since June 2007. LSEs are required to procure enough capacity to meet demand, plus a reserve margin, under the RPM. Capacity is procured through annual Base Residual Auctions (BRAs) three years in advance of the delivery year, which runs from June through May. First, Second and Third Incremental Auctions (IAs) are held 20 months, 10 months and 4 months ahead of the delivery year. Adjustments to capacity procurement are made during the IAs. By far the largest volume of capacity credits are settled in the BRAs.

The PJM Capacity Market hosted its most recent BRA in May 2022 for the 2023/2024 delivery year. The RTO clearing price fell to $34.13/MW-day in this auction compared to $50/MW-day in the 2022/2023 auction, which was held in May 2021. This was the lowest RTO clearing price since the 2013/2014 delivery year. It is important to note that PJM recently amended its Minimum Offer Price Rule (MOPR) in order to better accommodate renewable generation in the region. Originally, the PJM MOPR actually excluded new renewables that generated renewable energy credits (RECs) from bidding a price reflecting REC revenue or other subsidies. This was done in an attempt to mitigate the price-suppressive effects state-subsidized resources, especially nuclear plants and renewables, have in the capacity market. This would have effectively excluded renewables from participating in the capacity market at all. The new MOPR applies only to resources that exercise market power or receive conditioned state support. PJM defines conditioned state support as any state policies that, “improperly interfere with bidding in PJM's capacity market and FERC's ratemaking authority.” In PJM’s most recent auction, held in June 2022, the new less restrictive MOPR only applied to seven resources representing 76 MW. The auction saw a 25% increase in solar resources that cleared as well as an additional 5,315 MW of nuclear compared to the previous auction. Wind resources actually saw a decrease in cleared capacity, but that is due to the fact that fewer wind resources offered into the auction. Clearing prices from the 2023/2024 auction are shown below in Table 4. The 2023/2024 auction was originally scheduled for three years before the delivery period but was delayed to May 2022 (only one year before the delivery period) in order to accommodate new rule changes for the capacity market.

Table 4. Auction Clearing Prices for the Three Most Recent Auctions ($/MW-day)

Delivery Year	RTO	ComEd	Duke Energy Ohio & Kentucky	MAAC	EMAAC	BG&E
2023/2024	$34.13	$34.13	$34.13	$49.49	$49.49	$69.95
2022/2023	$50	$68.96	$71.69	$95.79	$97.86	$126.50
2021/2022	$140	$195.55	$140	$140	$165.73	$200.30

Source: PJM

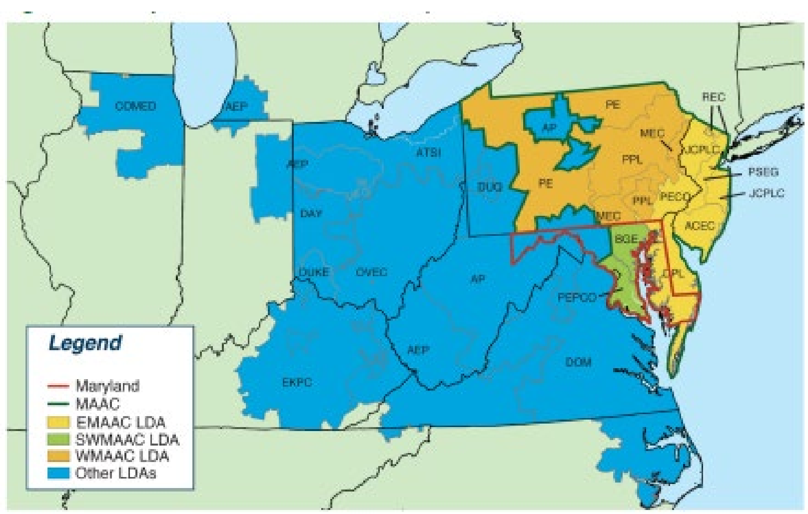
In total, nearly 145 GW of unforced capacity cleared in the most recent auction, representing a 21.6% reserve margin for the delivery year. 3,734.5 MW of new generation capacity cleared the BRA this auction.

1.6.1.1 RPM Market Structure

The RPM includes the following key features:

- Prices are set for sub-regions, called locational deliverability areas (LDAs). Initially, there were four LDAs, but the number of LDAs may increase or decrease depending on transmission development and constraints. Figure 12 shows the six main LDAs.

Figure 12. PJM Locational Deliverability Areas



Source: PJM State of the Market, Q3 2021

- Capacity prices tend to be generally higher in the Eastern parts of PJM due to the fact that the majority of load centers are located there, while supply in the region is generally located in the Western part of the RTO.
- Capacity resources include not only generating facilities but also DR resources and energy efficiency programs. The amount of DR that offered into the most recent auction decreased by 3.8% compared to the previous auction. All of the 5,471.1 MW of EE that offered into the 2023/2024 BRA cleared the auction. For comparison, only about 80% of the DR resources offered in the BRA cleared the auction.
- Capacity Performance (CP) resources were introduced in the 2018/2019 auction in an effort to reward resources that could be more reliably called upon, particularly in the winter months. CP resources receive a premium over base capacity but are expected to be available when needed throughout the entire delivery year and are subject to harsh non-performance penalties. For the past three auction periods, including 2022/2023, 100% of procured resources have been CP.
- Prices are determined based on a downward-sloping demand curve, meaning that the price will be determined based on the amount of capacity procured. If there is an excess of capacity, then the capacity price can go to zero. If there is a shortage of capacity, the price will rise to the price cap, which is 1.5 times the net Cost of New Entry (net CONE) in the LDA. Net CONE is an estimate of how much it would cost to build the most economical form of new generating capacity in that area, less margins earned from the sale of energy and ancillary services.

1.6.2 Ancillary Services Market

Ancillary services ensure operational reliability and prevent loss of load in the near-term. FERC identifies six ancillary services in Order 888:

1) Scheduling, system control and dispatch;
2) Reactive supply and voltage control from generation service;
3) Regulation and frequency response service;
4) Energy imbalance service;
5) Operating reserve—synchronized reserve service; and
6) Operating reserve—supplemental reserve service[9].

PJM procures regulation, energy imbalance services (i.e., real-time electricity), and both synchronized and supplemental reserves through market mechanisms. By contrast, PJM provides scheduling, system control and dispatch and reactive power on a cost basis. PJM also obtains black start services through a formulaic rate or on a cost basis[10].

[9] 75 FERC ¶ 61,080 (1996), page 200.

[10] 2018 State of the Market Report for PJM, Volume 2: Detailed Analysis, page 445.

Ancillary services support the reliable operation of the electric grid. PJM currently provides regulation and frequency response, energy imbalance, synchronized reserve, and non-synchronized reserve (operating reserves) through competitive markets. PJM provides energy imbalance services through the Real-Time energy market which is settled against the PJM Day-Ahead energy market position; therefore, a separate market is not required for this service. Markets are operated by PJM for the remaining three ancillary services.

PJM also procures Reactive Power and Voltage Support service under FERC-approved cost-of service rates. Reactive Power and Voltage Support is required to be provided by interconnecting generators under the terms and conditions of the Interconnection Service Agreement (“ISA”). Reactive Power and Voltage Support is a service that helps support the PJM transmission system by keeping transmission voltages within prescribed limits and supporting transfers of energy across the PJM system.

Reactive power compensation from PJM is a fixed monthly payment based upon the allocated capital cost from constructing the generator related to providing reactive power service and is paid regardless of how much or how often the generator is used to provide Reactive Power and Voltage Support by PJM. Generators whose active energy output is altered at the request of PJM for the purpose of providing reactive power to the grid are paid for lost opportunity costs (The hourly locational energy price less their energy market offer) if their output is reduced from their otherwise economic energy market output. In this way the generator compensated as if it was providing energy without the order to be backed down from its economic output.

Regulation reserve is a service that allows the system operator to adjust participating generation to accommodate short-term differences in system loads and resources. As demand increases or decreases from moment to moment, generation or DR resources are ramped up and down automatically, keeping the grid in balance. Beginning in October of 2012, resources were given a choice between two frequency response types to follow: Regal, which is a traditional and slower oscillation signal, and RegD, which is a faster oscillation signal. The redesigned market seeks to clear an optimal (least-cost) mix of the two types through one clearing price for regulation service. A FERC order in November 2012 adjusted PJM’s new regulation market rules; the order set the marginal benefits factor for RegD to a fixed value (1.0) for payment purposes. PJM’s regulation reserve prices have historically been significantly higher than neighboring regions and this has led to a large increase in the amount of energy storage resources entering the market to provide RegD. In response, PJM has capped the amount of RegD that it will procure, which is having an effect on the revenue of the participating storage resources. PJM is currently revising the RegA and RegD signals that resources will be following to better match their goals. This will likely further effect the operating patterns of storage in the market.

Originally limited to synchronized reserves, PJM’s primary reserve market now includes primary reserves that are not synchronized. To provide synchronized reserve, a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DR resources. In 2012, the RTO’s primary reserve requirement was 150% of the footprint’s largest contingency (2,063 MW), and 1,375 MW of that requirement must be synchronized. Non-synchronized primary reserves are those that could deliver energy within 10 minutes from a shutdown state, such as hydro and CTs. The ISO determines the optimal combination of synchronized and non-synchronized reserves to fulfill primary research requirements. Both the regulation and synchronized reserve markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The regulation and the synchronized reserve markets are cleared interactively with the energy market.

PJM introduced the Day Ahead Scheduling Reserve (DASR) market on June 1, 2008. The purpose of this market is to ensure sufficient supplemental or operating reserves are available to replace lost generation or transmission capacity within 30 minutes. Unlike regulation and synchronized reserve, DASR resources do not need to be online to provide reserve.

As seen in Table 5, regulation reserve prices have averaged between $13 and $44 over the last 7 years. The market redesign in October 2012—which implemented shortage pricing and decreased regulation requirements from 1% to 0.7% of peak load forecast—resulted in an increase in regulation costs and prices. The average regulation price was $26.00/MW of regulation in 2021, which was an increase from $13.55 in 2020. Regulation in 2020 was approximately 23% lower than the $16.27/MW average clearing price in 2019 and 50% lower than the average in 2018. Synchronized Tier 1 reserve prices have decreased recently, from ~$12/MW in 2015 to $1.62/MW in 2020 before rebounding in 2021. The greatest quantity of required reserve is for DASR, but as this capacity does not need to be online and the additional effects of COVID and warm winter weather, it commands the lowest price at $0.24 in 2021.

Table 5. PJM Ancillary Service Quantities and Prices (Nominal $)

Market	Avg Required MW in 2022	2014	2015	2016	2017	2018	2019	2020	2021
Regulation	On-Peak: 800 Off-Peak: 525	$44.15	$31.92	$15.72	$16.08	$25.32	$16.27	$13.55	$26.00
Synchronized Tier 1	1,654.8	$12.94	$11.88	$4.88	$3.73	$6.15	$3.01	$1.62	$8.41
DASR	4,882.7	$0.63	$2.99	$1.61	$2.12	$2.26	$2.27	$1.75	$0.24

Source: Guidehouse (Data from PJM State of the Market Reports)

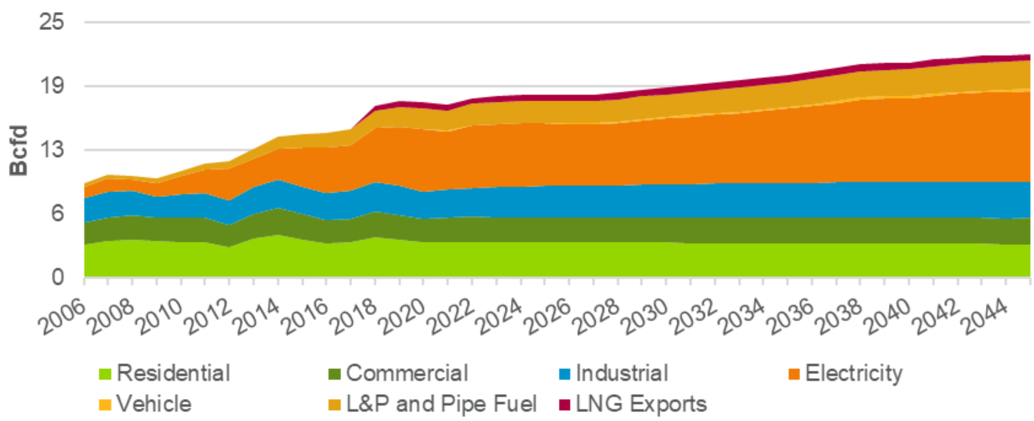
1.7 Fuels

1.7.1 Natural Gas – PJM Market

Demand

Natural gas demand in PJM increased significantly between 2006 and 2021, driven by a steep increase in electric generation gas usage, as shown in Figure 13. Total natural gas demand increased by 83.2% (4.4% per year) from 2006 to 2021, with electric generation gas usage increasing 453% (13.0% per year). Through 2045, Guidehouse forecasts more moderate demand increases in the PJM region as growth in the electric generation sector slows to annual growth rate of 1.7% per year. Advancements in energy efficiency are expected to keep residential and commercial growth relatively flat, while the introduction of LNG exports from Cove Point in 2018 will continue to add an additional 0.68 Bcfd of annual demand through 2045. Low natural gas prices will help drive industrial demand which is forecast to increase at an average annual rate of 1.1% year through 2045. Overall, between 2022 and 2045, total natural gas demand in PJM is expected to grow by 1.0% per year.

Figure 13: PJM Natural Gas Demand



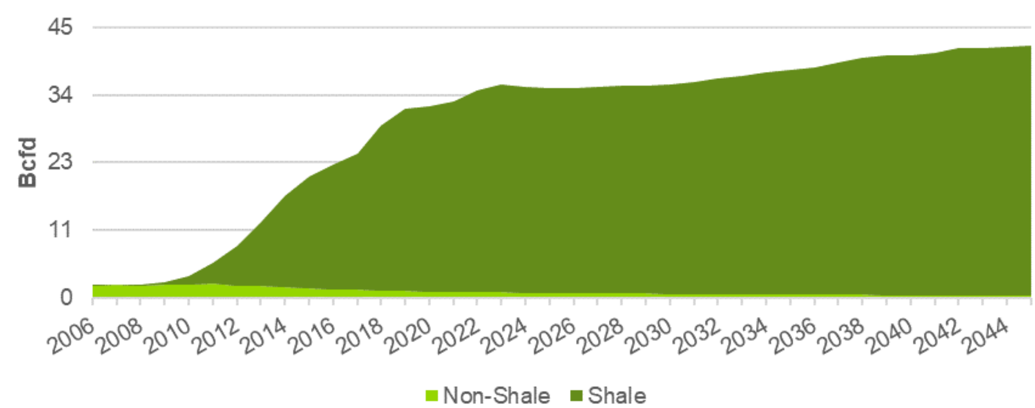
Source: Guidehouse's North America Natural Gas Market Outlook, Spring 2022; RBAC

Supply

The PJM region contains a majority of the Appalachian basin, one of the fastest growing producing regions in North America. Natural gas production in the PJM region has increased significantly over the last several years growing from just over 2 Bcfd in 2006 to 32.6 Bcfd in 2021. Most of the additional production in Appalachia is coming from the Marcellus shale play, the most prolific shale play currently developed in the U.S., which reached 24.7 Bcfd of production in 2021. A second natural gas resource, the Utica shale play, underlies the Marcellus.

Most of the production from the Utica shale play currently comes from Ohio, although the formation also lies under most of New York, Pennsylvania, and West Virginia, and adjacent parts of Kentucky, Maryland, Tennessee, Virginia as well as Ontario and Quebec in Canada. Activity in the play is increasing rapidly as the Utica shale play is proving to be relatively more economic for development due to its high liquid content with production growing from nearly zero in 2013 to 6.8 Bcfd in 2021. While both plays experienced some declines in production due to implications related to COVID-19 restrictions and the subsequent economic slowdown in 2020, Guidehouse forecasts a rebound in PJM regional production by 2022. After 2022, Guidehouse forecasts a much lower rate of growth in the Appalachian basin as limited pipeline takeaway capacity serves as a cap to production growth. Over the forecast period, Guidehouse expects production to grow by about 1.0% annually, reaching 41.8 Bcfd by 2045, as shown in Figure 14.

Figure 14: PJM Natural Gas Production



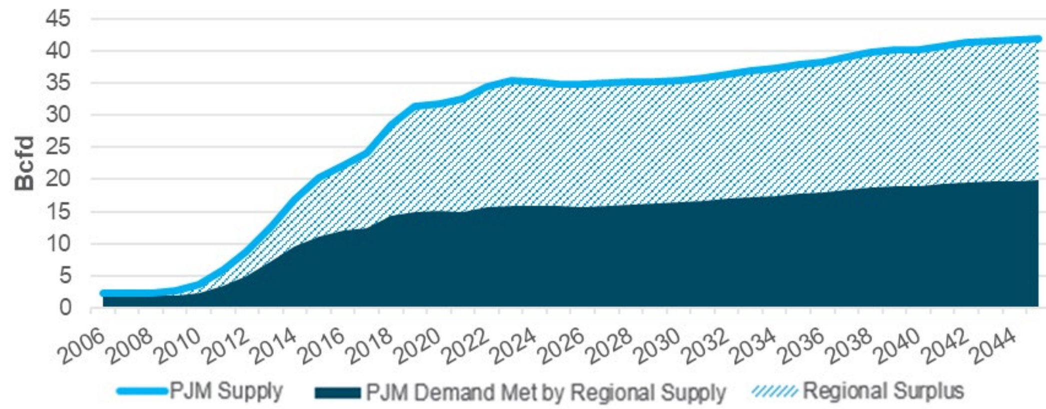
Source: Guidehouse's North America Natural Gas Market Outlook, Fall 2021; RBAC

Due to the increasing levels of production from the Marcellus and Utica shale plays, PJM now exports surplus gas to surrounding regions. Several pipeline projects have recently come online, including the 3.25 Bcfd Rover Pipeline project, the largest pipeline project in the area, to move surplus gas to surrounding demand areas[11]. As can be seen in Figure 15 below, PJM regional natural gas supply will continue to exceed regional demand for Appalachian gas, with the difference expected to reach about 22 Bcfd by 2045.

[11] Other major projects include Columbia Pipeline Group's Leach Express and Mountaineer Express; Columbia Gulf Transmission's WB Express; Transco's Atlantic Sunrise; and NEXUS Pipeline.

Note: Mountain Valley Pipeline and Atlantic Coast pipeline have been canceled or put on hold indefinitely and are not included in the Fall 2021 Outlook.

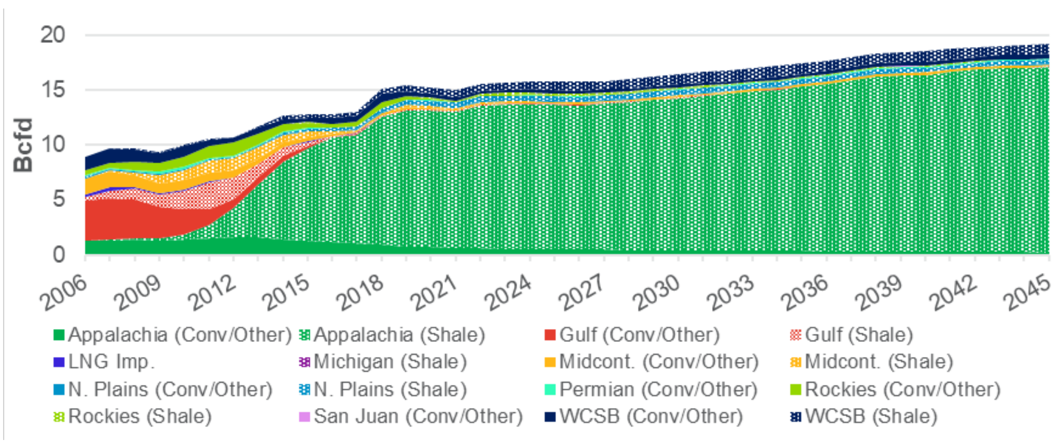
Figure 15: PJM Regional Gas Balance



Source: Guidehouse's North America Natural Gas Market Outlook, Fall 2021; RBAC

As seen in Figure 16, PJM has traditionally imported natural gas from a variety of surrounding supply areas. After 2008, when production from the Marcellus and Utica shale plays began to increase, PJM began to source most of its gas from Appalachia. Going forward, only small amounts of gas will be sourced from surrounding areas, primarily to meet seasonal demand in the northwestern parts of PJM that are located outside of the Appalachian basin.

Figure 16: Sources of Natural Gas for PJM Consumers



Source: Guidehouse's North America Natural Gas Market Outlook, Fall 2021; RBAC

2. STUDY BACKGROUND, ASSUMPTIONS, AND METHODOLOGY

2.1 Study Scope and Purpose

LG&E / KU engaged Guidehouse to inform and educate the company regarding the potential costs and benefits of joining PJM. This study simulated two cases: (1) the *SA Case* in which LG&E / KU remains a standalone balancing authority, and (2) the *RTO Case* in which LG&E / KU joins PJM.

2.2 Market Outlooks

Both the *Status Quo* and the *RTO* cases considered four market outlooks:

- Case 1: A baseline market scenario based on Guidehouse's Spring 2022 Reference Case and LG&E / KU provided fuel prices
- Case 2: A case in which national CO2 emissions reduction regulations are assumed
- Case 3: High fuel with no additional carbon emission regulations
- Case 4: High fuel with additional carbon emission regulations

Table 6. Case Matrix and Names

	Remain Standalone BA	Join PJM
Baseline Markets	Case 1 SA	Case 1 RTO
CO_2 Emissions Reduction	Case 2 SA	Case 2 RTO
High Fuel Prices	Case 3 SA	Case 3 RTO
High Fuel Prices and CO_2 Emissions Reduction	Case 4 SA	Case 4 RTO

2.2.1 Case 1: Baseline

The baseline scenario considers a future market structure with nominal forecasts for natural gas and coal prices and no CO_2 emissions requirements.

2.2.2 Case 2: Emission Reduction

The emission reduction scenario considers the implementation of national emission reduction regulations. An annual curve of CO_2 reductions from 2010 levels is achieved through the implementation of a national carbon price and adjustments to PJM's capacity expansion plan.

2.2.3 Case 3: High Fuel Prices

The high fuel prices scenario applies a sensitivity to natural gas and coal prices.

2.2.4 Case 4: High Gas with Additional Emission Regulation

Case 4 implements both the emission reduction strategy of Case 2 and the high fuel price sensitivity of Case 3.

2.3 Modeling Approach

2.3.1 Production Cost Modeling

This section provides a summary of the model setup and assumptions in Power System Optimizer (PSO), production cost market simulator used to develop each of the analyzed market scenarios. The forecast is formulated using wholesale energy price forecasts from Guidehouse's Spring 2022 Reference Case forecast, augmented with LG&E / KU's provided parameters.

Guidehouse forecasts energy prices in the contiguous United States using a PSO simulation. Guidehouse forecasts ancillary service prices using an econometric approach that considers the historical relationship between energy prices and regulation and reserve prices in different regions, combined with the PSO energy price forecast.

2.3.2 Areas

The base PSO model is set up to allow flexibility between energy balancing and reserve pooling. The input streams such as load forecasts, generator location, transmission topology, and more are based on the hierarchy of energy areas. The "RTO" area allows PSO to balance multiple areas together in the model, and allows energy and reserves to be optimized together or separately.

In the market outlooks in which LG&E / KU remains a standalone BA, PSO balances the area as an individual unit, separate from neighboring BAs.

In the market outlooks in which LG&E / KU joins PJM, PSO is able to balance LG&E / KU either separately or in conjunction with PJM in order to achieve the least cost, and for energy and reserves to be properly optimized.

2.3.3 Load Forecast

LG&E / KU provided an hourly load profile for the forecast period which was inputted to PSO which was developed by LG&E / KU as part of their 2023 Business Plan.

2.3.4 Hurdle Rates

Hurdle rates are used for transactions between energy areas to simulate the costs of transferring power from one area to another, as well as to approximate the opportunity costs of bilateral trades.

PSO, like many production cost software suites, optimizes transmission and energy transfers as part of the algorithm that balances generation and load. Functionally a $10/MWh hurdle rate means that if the balance price in Area A is at least $10/MWh more than adjacent Area B, then energy will be transferred from Area B to Area A with a $10/MWh premium. Area A's generation is decreased, and Area B's generation is increased equally.

One portion of the costs represents the additional transmission costs for moving power from Area A to Area B. The second portion of the costs represents the opportunity costs of bilateral trading. In other words, energy traders typically do not trade power unless there is some profit in the trade to make it worth their time to execute.

As BA's begin to participate in various markets, the combined transmission and generation costs become optimized over broader footprints. Additionally, the opportunity costs decrease as it becomes easier for entities to trade power amongst each other. As such, the hurdle rate inputs represent key differences in the ways that energy markets' behavior changes.

The applied hurdle rates below represent the combined transmission costs and opportunity costs.

Table 7. Hurdle Rates

	LGE > PJM	PJM > LGE
Standalone Cases	$16.90/MWh	$30.02/MWh
RTO Cases	$0.00/MWh	$0.00/MWh

2.3.5 Reserves

Operating reserves is capacity held back for unexpected losses of generation or to cover variability in both generation and loads. Loss of generation can be due to a generation unit outage or unexpected loss of renewable generation. The operating reserves are modeled differently based on the market structure and configuration of each case.

Operating reserves are maintained by the entity with NERC responsibilities. The individual BA's are responsible for providing reserves, except for participation in an RTO. In the postulated RTO scenario, it would be expected that PJM would administer the required reserves, and that LG&E / KU would be absolved of reserve responsibilities.

In the PJM scenario, reserves are co-optimized with generation amongst all RTO participants, including LG&E / KU.

2.3.5.1 Spinning Reserves

Spinning reserves are assumed to be 3% of load for LG&E / KU. Spinning reserves represent the portion of the capacity responsible for near-term balancing needs. Spinning reserves may only be supplied by units already online and synchronized to the grid.

Table 8. Standalone Spinning Reserves Requirements

	Activation Time (min)	PJM > LGE
Regulation up	5	1%
Spinning Reserves	10	2%

Spinning reserves are supplied by LG&E / KU unless it is a market participant of PJM.

2.3.6 Fuel Prices

LG&E / KU provided natural gas and coal price forecasts for both the baseline scenario and the two high-fuel scenarios. LG&E / KU's monthly natural gas prices and annual coal prices were used as model inputs in this analysis and are available in Appendix A.

2.3.7 Interchange Limits

The interchanges represent economic limits on the amount of energy that can be transferred between two areas. The limits are primarily based on transmission capacity and ownership. Only the handful of paths in the topographical vicinity of LG&E / KU are focused on in this analysis.

The export capability of LG&E / KU is capped at 300 MW which is consistent with historical transactions between LG&E / KU and PJM.

Interchanges between TVA, MISO, and EEI are disabled to simplify the analysis and to isolate the effects of PJM RTO participation.

2.3.8 Carbon Regulation Cases and Carbon Prices

To achieve the assumed carbon reduction regulations, two things were done: a federal carbon price was implemented, and the expansion plan was adjusted to shift generation away from emitting resources. The expansion plan is discussed further in Section 3.3.

The following carbon prices were used:

Table 9. Carbon Prices used in Carbon Regulation Cases

Year	CO_2 Emission Price ($/ short ton)
2025	$ 14.73
2026	$ 15.40
2027	$ 16.09
2028	$ 16.80
2029	$ 17.55
2030	$ 18.33
2031	$ 19.16
2032	$ 20.03
2033	$ 20.95
2034	$ 21.90
2035	$ 22.90
2036	$ 23.94
2037	$ 25.03
2038	$ 26.17
2039	$ 27.37
2040	$ 28.62

2.3.9 Capacity Prices

Guidehouse forecasts short term capacity prices using a supply-demand model. Guidehouse models a supply curve which reflects existing PJM generating capacity and expected near-term additions and retirements. The demand curve is based on the most recent PJM demand curve parameters and load forecasts.

Long-term prices are based on Guidehouse's forecast of the Net CONE of a generic combined-cycle unit. Guidehouse utilizes internal capital costs assumptions, together with energy and ancillary service margin results from its production-cost model, to calculate Net CONE over the forecast period. In the long-term RTO prices fluctuate between $57 and $73/MW-day over the final 10 years of the forecast. MAAC and EMAAC prices trend above RTO in the long term due to higher expected net CONE prices in these regions, driven by higher regional capital costs and lower energy & ancillary services revenues. Year-to-year changes in long-term capacity prices are driven by fluctuations in forecasted combined-cycle energy & ancillary services revenues.

Capacity prices are based on the "missing revenue required" to attract investments based on the region-specific Net Cost of New Entry ("Net CONE"), which equals the Gross Cost of New Entry ("Gross CONE") minus the expected Energy & Ancillary Service Offsets ("E&AS Offsets") for the marginal capacity resource in the region. The short-term forecasts for PJM are the exceptions to this approach. Because PJM has a centrally administered capacity market with a known set of potential supply resources and a forecastable demand curve (i.e., the Variable Resource Requirement ("VRR") curve), for the first three years of the forecast Guidehouse creates a supply stack based on our estimate of unit-specific avoided costs, calibrated to recent auction results, and known retirements and new entrants. Guidehouse bases the demand curve on the most recently available VRR curve parameters and forecast peak load growth in RTO, MAAC, EMAAC, and RTO.

In regions without a formal capacity auction, Guidehouse calculates the value of capacity that a generator would receive as part of a bilateral contract with a load serving entity based on the region-specific Net CONE, policies, and capacity needs.

3. CAPACITY EXPANSION

The capacity expansion was performed to project LG&E / KU's future portfolio for the various scenarios. Appendix B presents annual additions and retirements for each case.

3.1 Standalone Build

The standalone expansion was built to a 25% winter / 16% summer reserve margin on an installed capacity basis. The standalone build is used for every standalone scenario. The Effective Load Carrying Capacity (ELCC) used for standalone capacity calculations are:

Table 10. Standalone ELCC's

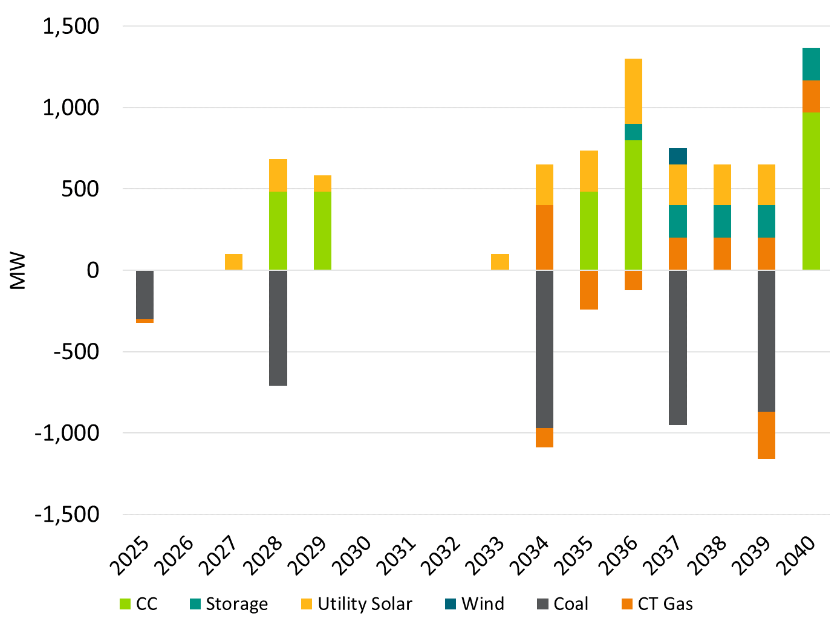
	Summer	Winter
Solar	79%	0%
Wind	24%	32%

Usually, large thermal retirements are replaced with a similar capacity of thermal units and a small amount of renewables. For example, 709 MW of coal is retired with Mill Creek 2 and E W Brown 3 in the year 2028. This capacity is replaced with two CC's totaling 968 MW over the years 2028 and 2029 which is required to maintain the spinning reserve requirements. Solar units totaling 300 MW of nameplate capacity come online during the same timeframe. This combination of CC and solar units provides a lower cost to serve load than alternative portfolio options.

Table 11. Standalone Reserve Margins

Year	Effective Summer Capacity Reserve (%)	Effective Winter Capacity Reserve (%)
2025	21.1%	30.3%
2026	21.0%	31.0%
2027	19.4%	25.5%
2028	17.3%	34.0%
2029	25.5%	33.9%
2030	25.3%	33.7%
2031	25.3%	33.7%
2032	25.3%	34.2%
2033	25.8%	24.5%
2034	16.4%	29.3%
2035	21.5%	43.5%
2036	35.5%	35.5%
2037	27.7%	42.4%
2038	34.5%	29.6%
2039	23.0%	50.8%
2040	44.0%	33.9%

Figure 17. Capacity Additions and Retirements (MW) – Standalone Cases



3.2 RTO Build

In the RTO scenario LG&E / KU's expansion plan differs as procuring capacity from PJM's capacity market will become an option. As a load serving entity, LG&E / KU must still maintain a reserve margin within the territory per PJM's Fixed Resource Requirement rules, however the requirement is much smaller than the reserve requirements as a standalone BA. The requirements are based on peak summer demand, and do not vary by season as LG&E / KU's current reserve margin requirements do. The applied PJM ELCC's are the same year-round, and are a mis of PJM published values in the early years and Guidehouse's ELCC methodology in the later years. Guidehouse's methodology takes into account relative renewables penetration and impact to peak load.

The reserve margin calculations when part of PJM are performed differently than when LG&E / KU is a standalone entity. Rather than calculate the effective capacity margin to the peak load using ICAP values, PJM has a system called the Fixed Resource Requirement (FRR) which ensures that participating Load Serving Entities (LSE's) maintain enough capacity within their zone to enable the entity to provide its own capacity should it elect to do so (as opposed to purchasing the capacity from the market). This method requires knowing the LSE's peak load coincidence with the rest of PJM and PJM's Forecast Pool Requirement (FPR). Additionally, the PJM margin calculation is performed with unforced capacity (UCAP) as opposed to nameplate capacity (ICAP). The UCAP values are calculated on a per-unit basis with each individual units' forced outage rate in PSO.

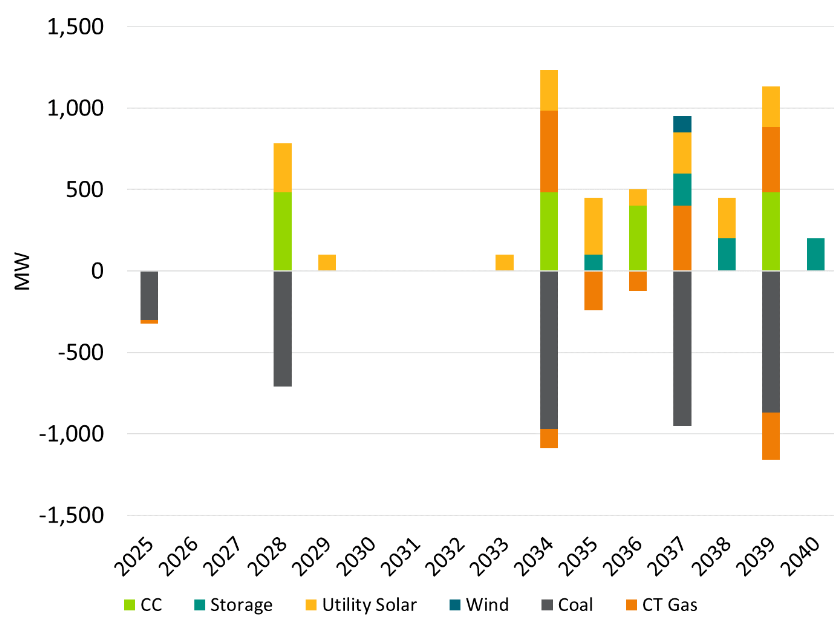
LG&E / KU forecasts a peak load coincidence factor of 92% based on historical peak load coincidence vs PJM peak loads. The recommended FPR in PJM is 1.0918. This puts the annual LG&E / KU capacity requirements on an unforced capacity basis equal to:

(Peak Demand) * (92%) * (1.0918)

Table 12. RTO FPR and Margins

Year	FPR	Margin
2025	6,331	13.2%
2026	6,336	13.1%
2027	6,456	11.0%
2028	6,453	10.1%
2029	6,450	10.7%
2030	6,448	10.6%
2031	6,445	10.6%
2032	6,442	10.5%
2033	6,439	11.1%
2034	6,436	11.2%
2035	6,433	10.7%
2036	6,431	15.5%
2037	6,428	11.5%
2038	6,425	15.2%
2039	6,422	12.4%
2040	6,419	15.1%

Figure 18. Capacity Additions and Retirements (MW) – RTO Cases



3.3 Carbon PJM Build

Additional capacity changes are made in PJM as part of the strategy to reduce CO_2 as compared to 2010 CO_2 levels. Along with the carbon prices and regulation, discussed in Section 2.3.8, the PJM build was adjusted to meet the required targets.

The LG&E / KU build was not adjusted for this as the retirements were already aggressive for the portfolio. Since LG&E / KU reserve margins were already dropping almost to requirement amounts by 2028, PJM changes were instead made to meet the global targets as it is much easier for PJM to accommodate these adjustments.

Table 13. Study Target Emissions Reductions from 2010 Levels

	Targeted Carbon Reduction
2025	-19%
2026	-23%
2027	-28%
2028	-32%
2029	-37%
2030	-41%
2031	-44%
2032	-47%
2033	-50%
2034	-53%
2035	-57%
2036	-60%
2037	-63%
2038	-66%
2039	-69%
2040	-72%

Table 14. Additions and Retirements (MW) in Emission Reduction Cases

Year	Wind	PV	IC/GT	Coal
2025	310	455	0	0
2026	464	317	0	0
2027	257	348	0	0
2028	559	165	0	0
2029	87	119	0	0
2030	176	655	0	-620
2031	52	154	0	0
2032	131	511	500	-850
2033	63	521	0	-850
2034	311	593	400	0
2035	227	164	0	0
2036	216	146	0	0
2037	234	143	0	0
2038	352	164	0	0
2039	469	171	0	0
2040	449	141	0	0

4. PJM EVALUATION

The benefits and costs of LG&E / KU joining PJM are evaluated by comparing a business-as-usual or status-quo case with an alternative in which LG&E / KU joins PJM. Given the complexity of obtaining necessary approvals and preparing for full operational integration, the study uses 2025 as the start year of PJM entry. The benefits and costs are provided in terms of real 2020 dollars over the 2025 – 2040 period.

4.1 Benefits/Costs from Joining PJM

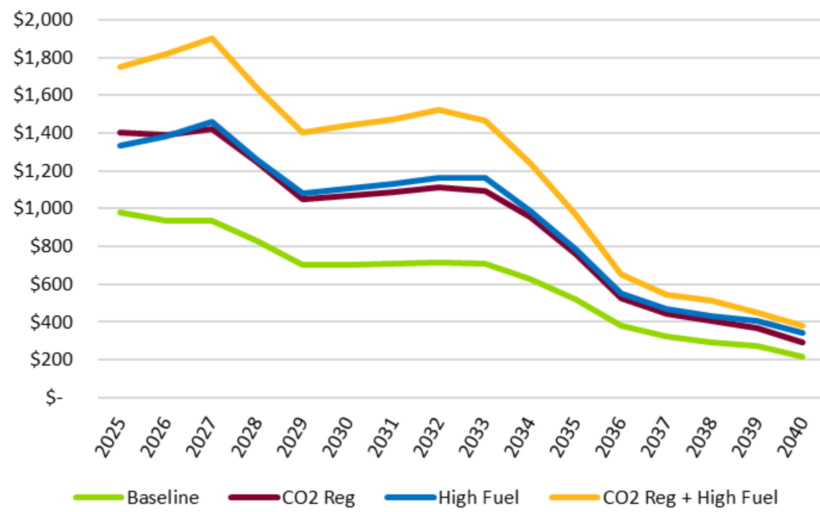
4.1.1 Adjusted Production Cost Impacts

In general, access to a larger market with reduced trading barriers creates more opportunities for economic energy purchases and sales. Also, joining a more expansive geographical footprint allows generators to operate more efficiently due to shared operating reserve requirements and the reduced need to carry reserves for renewable balancing. Both result in adjusted production cost savings, or dispatch benefits, and are assessed using PSO by comparing the SA Case to a case in which LG&E / KU is part of PJM (the Join PJM case). Adjusted production cost savings represent the savings in dispatch (fuel, variable O&M and emissions) costs, energy trading (purchase costs net of sales revenue), and ancillary services.

A breakdown of production costs is tabularized in Appendix C. The annual import and export costs can appear to vary significantly when the volumes are small. There are a handful of anomalous hours throughout the production cost runs in which reserve violations or other similar modeling costs increase the LMP for an hour, and these penalties will always occur during an hour with imports or exports due to the nature of how PSO attempts to match demand and supply.

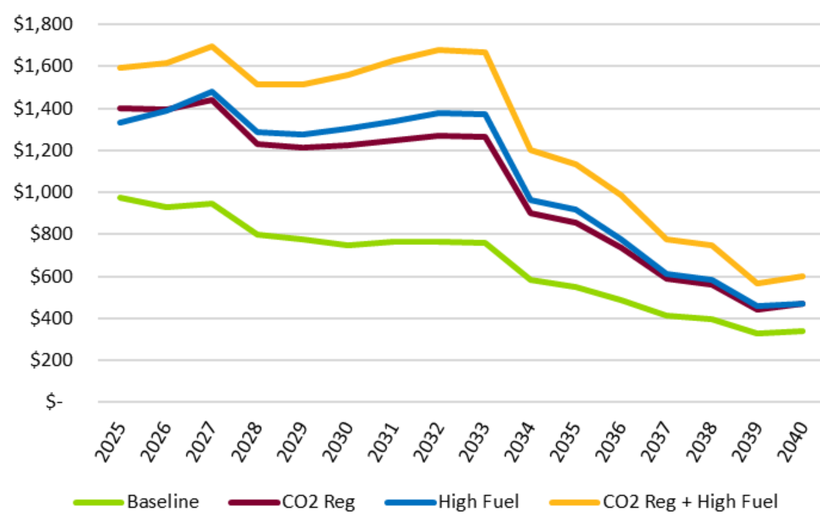
SA Case

Figure 19. Standalone Annual Production Costs ($mil)



RTO Case

Figure 20. RTO Annual Production Costs ($mil)



4.1.2 Imports and Exports

SA Case

In the majority of standalone scenarios and years LG&E / KU is a net exporter.

However, in the emission reduction cases the imports outweigh the exports until approximately 2035. At this point the intersection of energy prices and carbon prices causes the results to begin favoring exporting.

Figure 21. Standalone Imports (MWh)

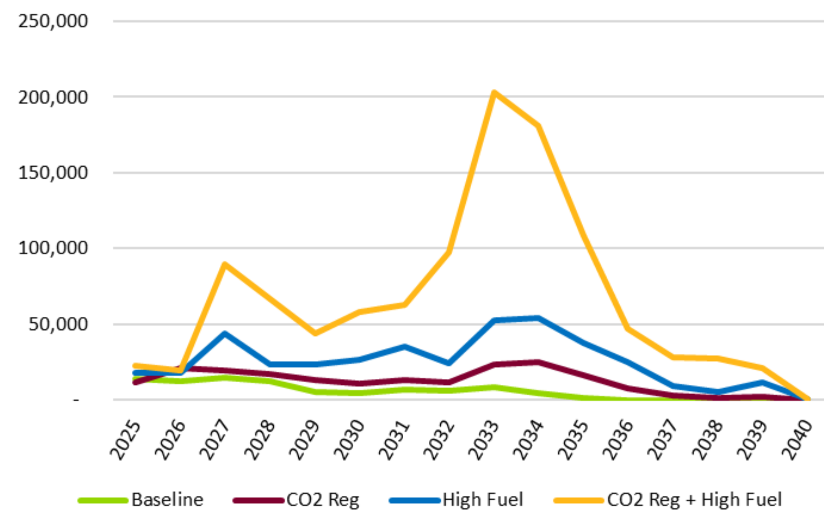
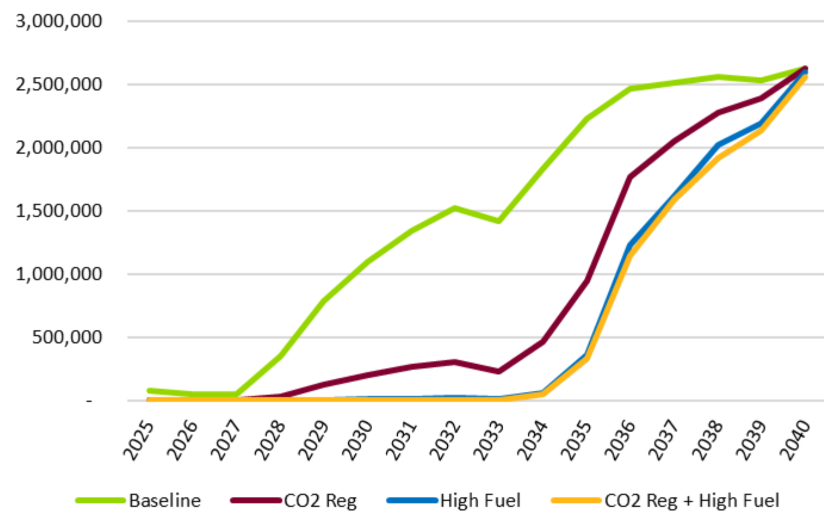


Figure 22. Standalone Exports (MWh)



RTO Case

In the majority of RTO scenarios and years LG&E / KU is a net importer. The imports are significantly higher due to the removal of the RTO hurdle rates. By drastically lowering the transaction costs with PJM, imports frequently replace what would otherwise be marginal LG&E / KU generation. By 2035 the trends somewhat converge with the standalone cases. Once Ghent retires and new efficient CC's are built, LG&E / KU becomes a net exporter to PJM again.

Figure 23. RTO Imports (MWh)

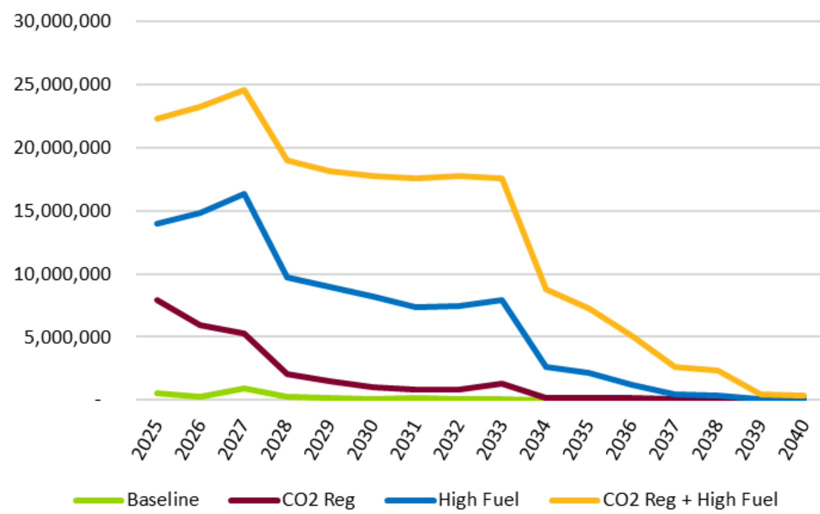
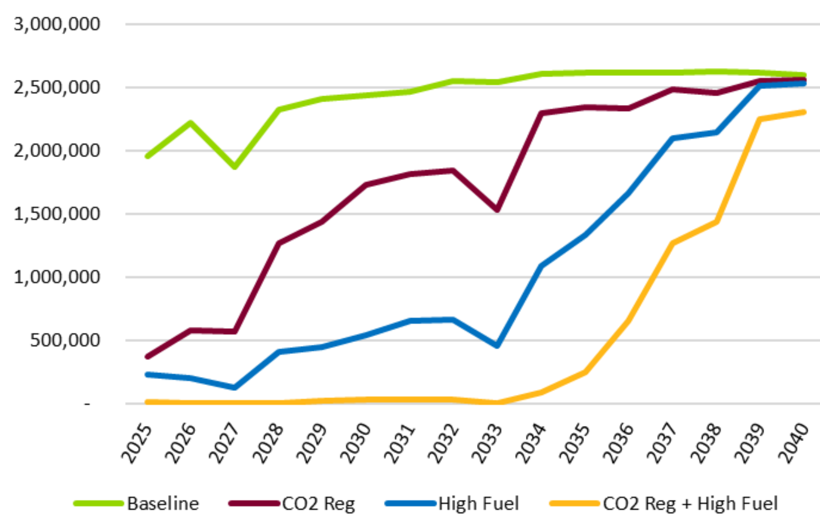


Figure 24. RTO Exports (MWh)



4.1.3 Annual LG&E / KU generation by technology

Appendix D contains generation by unit type in MW and as a percentage of total generation per year for each case.

SA Case

In the SA cases, total generation remains relatively steady throughout the forecast period, consistent with the relatively steady load. In each case, PV, CC, and IC/GT generation increase and coal generation decreases. There are only small differences in the generation mixes of the SA cases. Neither the carbon constraints (applied to Cases 2 and 4) nor the high fuel prices (applied to Cases 3 and 4) yield significant differences in the generation mix.

Figure 25 through Figure 28 display the generation by unit type throughout the forecast period for Cases 1-4 SA.

Figure 25. Case 1 SA - Generation by Unit Type (MWh)

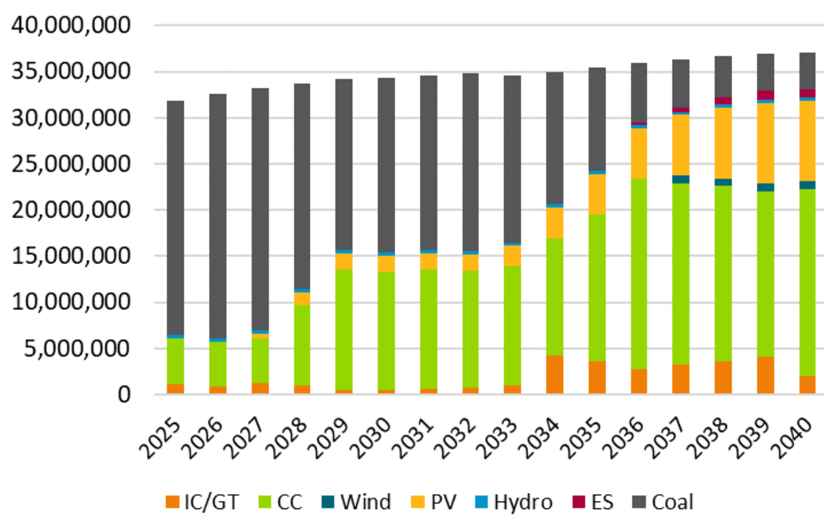


Figure 26. Case 2 SA - Generation by Unit Type (MWh)

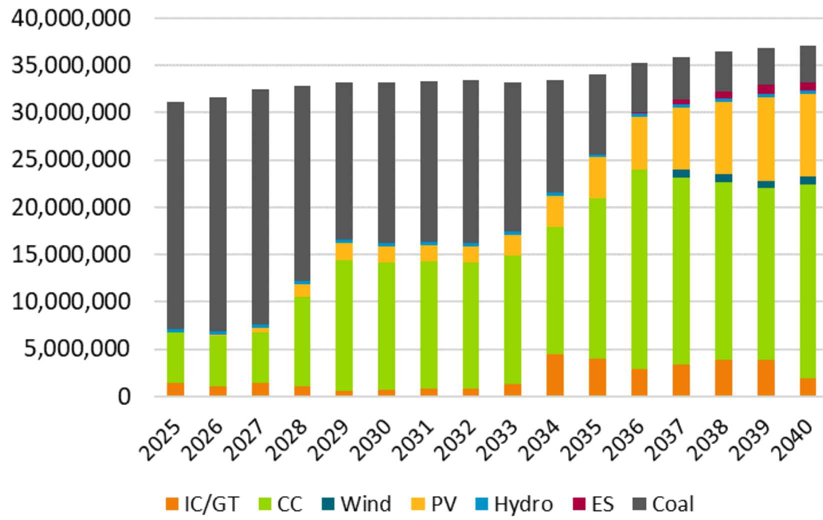


Figure 27. Case 3 SA - Generation by Unit Type (MWh)

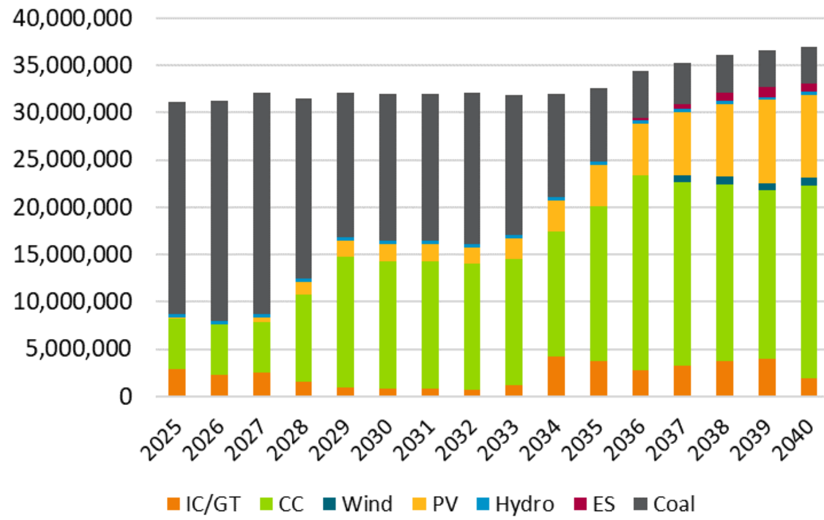
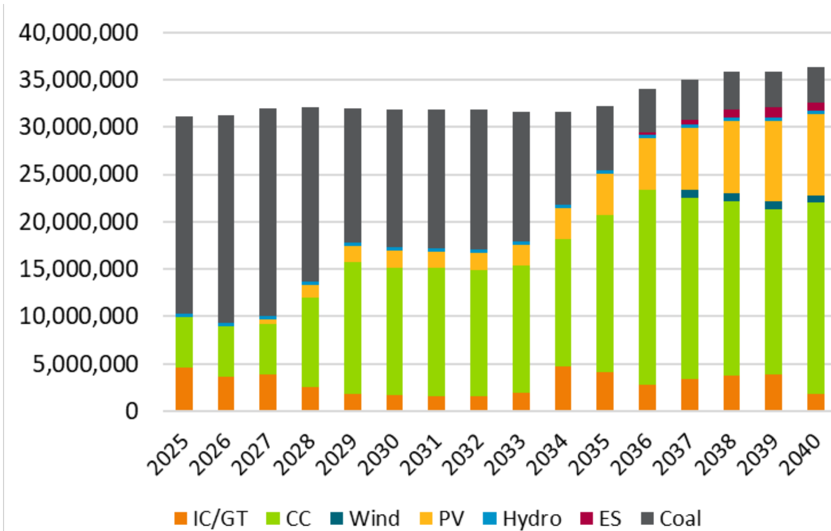


Figure 28. Case 4 SA - Generation by Unit Type (MWh)



RTO Case

In the RTO cases, LG&E / KU's generation is significantly lower than the SA cases between 2025-2027 because it is optimal for LG&E / KU to import power to serve its load. This is attributable to relatively higher prices within LG&E / KU than in PJM in the near term, and to the absence of hurdle rates in the RTO cases.

In the long-term, falling LG&E / KU prices, rising PJM prices, and transmission constraints out of LG&E / KU's territory make it optimal for LG&E / KU to increase generation and use this power to serve its load in the RTO case. Case 1, with base fuel prices and no carbon constraints, has the highest generation in the near term. The carbon constraints in Cases 2 and 4, and the increased fuel prices in Case 3 and 4, each lead to decreased generation in the near-term when PJM prices are higher than LG&E / KU prices.

LG&E / KU's generation increases and total generation by the end of the forecast period is approximately equal to total generation in the SA cases. Throughout the forecast period, prices within PJM increase, while prices in LG&E / KU decrease. Exports out of LG&E / KU are capped at 300 MW in the model to be consistent with historical trends and transmission limitations.

Total generation increases slightly in 2028 as solar generation increases. In 2034 following the retirement of ~700 MW of coal capacity, generation is replaced with PV, IC/GT and CC generation. This new block of generation is much more efficient than the retired coal capacity and takes up a larger share of the generation mix. In all cases, solar generation increases and coal decreases over time.

Figure 29 - Figure 32 display the generation by unit type throughout the forecast period for Cases 1-4 RTO.

Figure 29. Case 1 RTO - Generation by Unit Type (MWh)

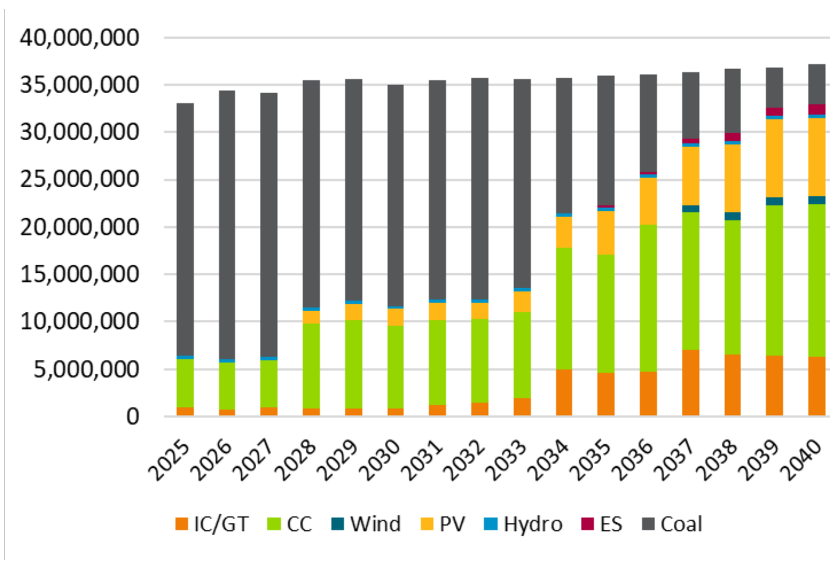


Figure 30. Case 2 RTO - Generation by Unit Type (MWh)

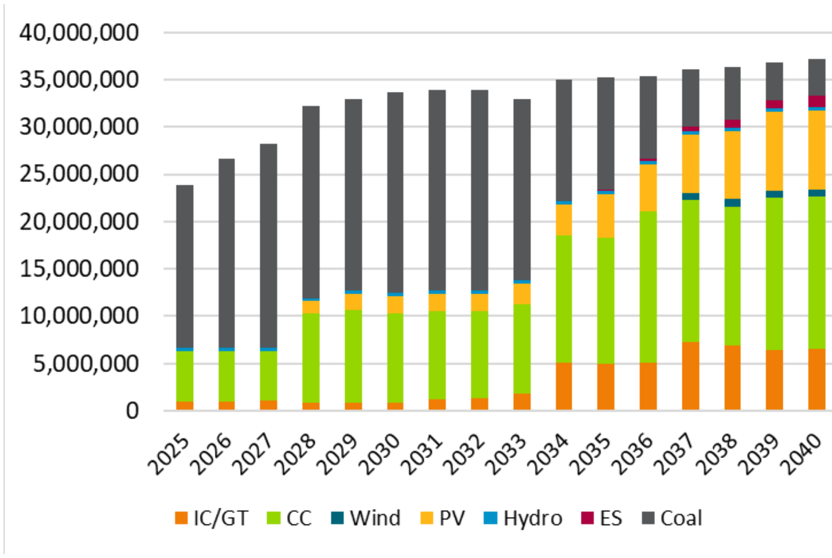


Figure 31. Case 3 RTO - Generation by Unit Type (MWh)

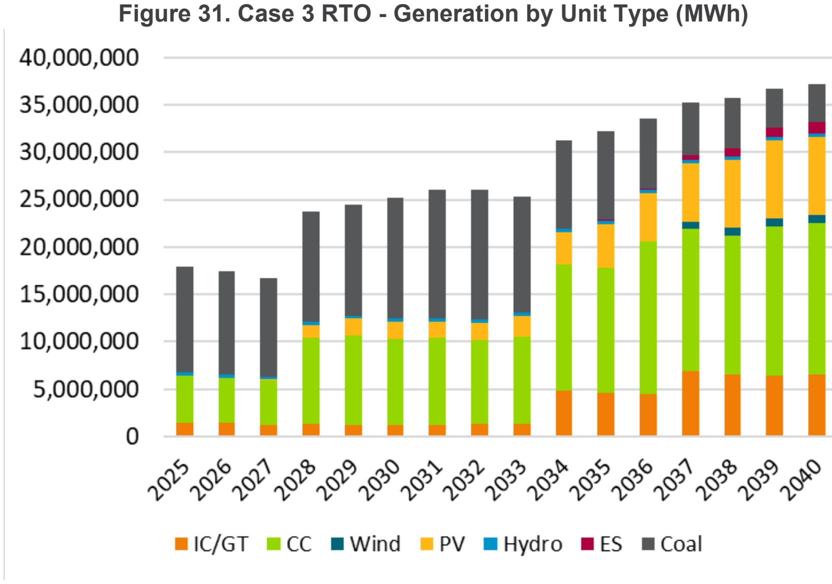
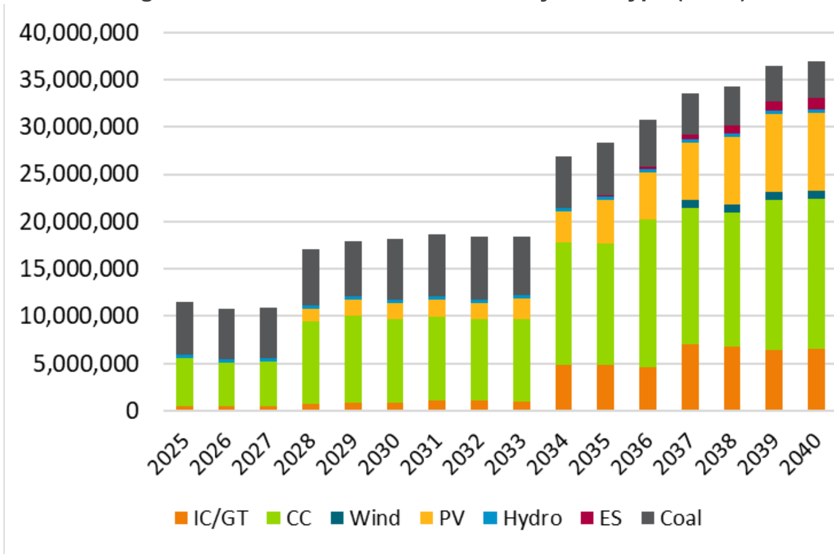


Figure 32. Case 4 RTO - Generation by Unit Type (MWh)



4.1.4 Annual emissions by generators within LG&E / KU's service territory

Appendix E contains total emissions, percent reduction from 2010 values, and emissions costs for each case.

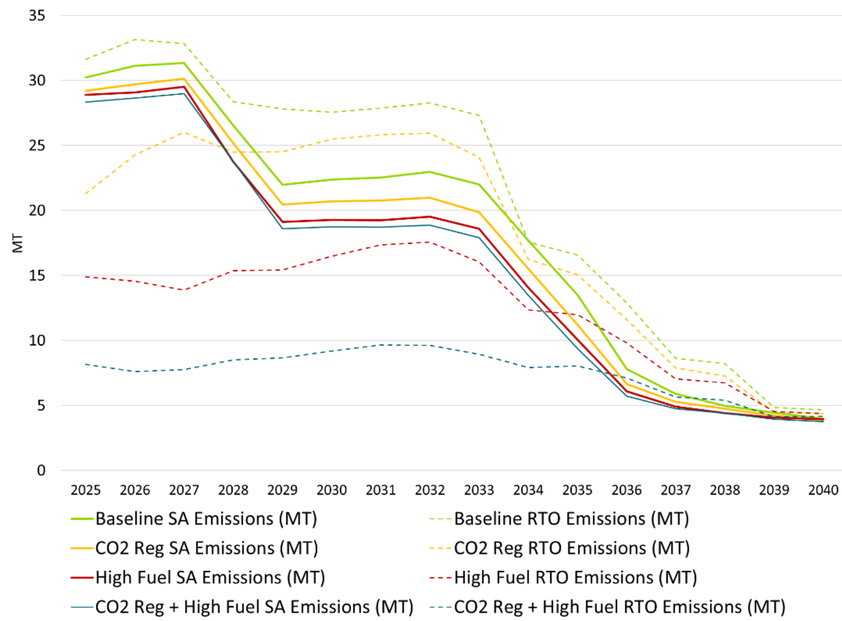
Case 1, representing baseline markets, has the highest emissions in both the SA and the RTO cases, followed by Case 2 (emissions reductions with base fuel prices), Case 3 (no emissions reductions and high fuel prices), and Case 4 (emissions reductions with high fuel prices), which has the lowest emissions in both the SA and the RTO cases.

Cases with high fuel prices (Cases 3 and 4) have the lowest total emission throughout the forecast. The high fuel prices lead to reduced reliance on thermal generation, an increase in imports in the short-term, and subsequently lower emissions from generation. High fuel prices are more influential in reducing emissions than carbon constraints.

Differences between cases are most pronounced in the near term and between RTO cases than SA cases, reflecting the differences in generation discussed above. In the long-term, total become relatively constant between cases.

Compared to the 2010 baseline of 39.5 million short tons, by 2040 Case 4 SA has the highest reduction (91%), the remaining cases each reduce emissions by 88-90% compared to 2010 levels.

Figure 33. Carbon Emissions by Case (million short tons)



4.1.5 Capacity Prices

Capacity prices for the RTO cases are presented below. Generally, prices follow PJM's reserve margins.

Short term RTO capacity prices clear in the $41/MW-day to $48/MW-day range, which follows the trend of the 2023/2024 auction and remains depressed. The announced un-retirement of Byron and Dresden nuclear plants, and a number of solar and wind new entry are expected to put downward pressure on capacity prices. The revised Minimum Offer Price Rule (MOPR) is also expected to put downward pressure on capacity prices, as state-subsidized resources are no longer subject to MOPR and able to justify lower offer prices, so long as they are not identified as attempting to exert Buyer-Side Market Power or receiving Conditioned State Support. Under the new Market Seller Offer Cap (MSOC) rule, the default MSOC is set at the unit-specific net Avoidable Cost Rate (ACR), and resources are required to justify their offers by going through a unit-specific review process if offering above the default ACR cap. The new MSOC rule is expected to mitigate market power concerns and put downward pressure on capacity prices.

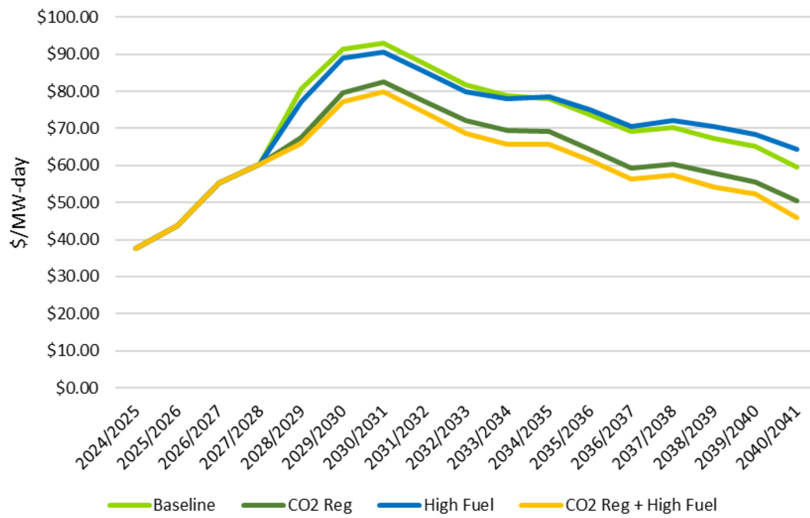
The high fuel prices somewhat affect the results, however the Net CONE is based on modern CC's which are frequently operating lower than the marginal system cost. The high fuel prices and efficient CC operations largely offset with respect to capacity prices.

The carbon regulated cases unintuitively have a decreased capacity cost. Ordinarily the capacity prices would be expected to increase as CO_2 prices increase. Increased CO_2 emissions prices yield more expensive thermal operation which decreases energy revenue. Thermal units must therefore be compensated via additional capacity revenue. However, the build changes that were made in order to meet carbon reduction targets (see Section 3.3), particularly the early coal requirements, lead to additional energy revenues for the CC's which run at a high capacity factor. These additional energy revenues are a greater magnitude than the additional expenses due to CO_2 prices, therefore leading to lower capacity prices.

Table 15. RTO Capacity Prices ($/MW-day)

Year	Baseline Case 1 RTO	CO_2 Regulated Case 2 SA	High Fuel Prices Case 3 SA	High Fuel Prices + CO_2 Regulated Case 4 SA
2024/2025	$37.53	$37.53	$37.53	$37.53
2025/2026	$43.86	$43.86	$43.86	$43.86
2026/2027	$55.32	$55.32	$55.32	$55.32
2027/2028	$60.44	$60.44	$60.44	$60.44
2028/2029	$80.59	$67.45	$77.28	$65.96
2029/2030	$91.40	$79.67	$88.85	$77.23
2030/2031	$93.09	$82.42	$90.68	$79.81
2031/2032	$87.31	$77.25	$85.22	$74.21
2032/2033	$81.74	$72.15	$79.94	$68.73
2033/2034	$78.68	$69.48	$77.93	$65.77
2034/2035	$77.86	$69.17	$78.60	$65.57
2035/2036	$73.84	$64.36	$74.95	$61.35
2036/2037	$69.12	$59.15	$70.59	$56.41
2037/2038	$70.19	$60.34	$72.06	$57.26
2038/2039	$67.26	$57.82	$70.40	$54.30
2039/2040	$65.20	$55.60	$68.26	$52.20
2040/2041	$59.44	$50.36	$64.24	$45.94

Figure 34. Capacity Prices ($/MW-day)



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APPENDIX A: FUEL PRICES

Base Fuel Price Cases – Case 1 and Case 2

Table A1. Natural Gas Prices – Base Case (2020$/MMBtu)

Year	Month	Henry Hub	EW Brown	Cane Run	Haefling	Mill Creek	Paddy' Runs	Trimble County
2025	1	[redacted]						
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
2026	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
2027	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							

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	11	[redacted]
	12	
2028	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2029	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2030	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2031	1	
	2	
	3	

CONFIDENTIAL INFORMATION REDACTED

	4	[redacted]
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2032	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2033	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2034	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	

CONFIDENTIAL INFORMATION REDACTED

	9	[redacted]
	10	
	11	
	12	
2035	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2036	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2037	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2038	1	

	2	[redacted]
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2039	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2040	1	
	2	
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	10	
	11	
	12	

CONFIDENTIAL INFORMATION REDACTED

Table A2. Coal Prices – Base Case (2020$/MMBtu)

Year	Brown HS	Ghent HS	Mill Creek	Trimble Co	Trimble Co PRB
2025	[redacted]				
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

High Fuel Price Cases – Case 3 and 4

Table A3. Natural Gas Prices – High Fuel Price Case (2020$/MMBtu)

Year	Month	Henry Hub	EW Brown	Cane Run	Haefling	Mill Creek	Paddy' Runs	Trimble County
2025	1	[redacted]						
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
2026	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
2027	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							

CONFIDENTIAL INFORMATION REDACTED

2028	1	[redacted]
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2029	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2030	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2031	1	
	2	
	3	
	4	
	5	

CONFIDENTIAL INFORMATION REDACTED

	6	[redacted]
	7	
	8	
	9	
	10	
	11	
	12	
2032	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2033	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2034	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	

CONFIDENTIAL INFORMATION REDACTED

	11	[redacted]
	12	
2035	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2036	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2037	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2038	1	
	2	
	3	

CONFIDENTIAL INFORMATION REDACTED

	4	[redacted]
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2039	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2040	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	

Table A4. Coal Prices – High Fuel Price Case (2020$/MMBtu)

Year	Brown HS	Ghent HS	Mill Creek	Trimble Co	Trimble Co PRB
2025	[redacted]				
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					

APPENDIX B: CAPACITY ADDITIONS AND RETIREMENTS

Standalone Cases

Table B1. Standalone Capacity Expansion and Reserve Margins

Year	Effective Summer Resource Capacity (MW)	Peak Summer Demand (MW)	Effective Summer Capacity Reserve (%)	Effective Winter Resource Capacity (MW)	Peak Winter Demand (MW)	Effective Winter Capacity Reserve (%)
2025	7,630	6,303	21.1%	7,891	6,058	30.3%
2026	7,630	6,308	21.0%	7,939	6,058	31.0%
2027	7,676	6,427	19.4%	7,800	6,213	25.5%
2028	7,537	6,425	17.3%	8,322	6,211	34.0%
2029	8,056	6,422	25.5%	8,313	6,210	33.9%
2030	8,044	6,419	25.3%	8,301	6,209	33.7%
2031	8,040	6,416	25.3%	8,297	6,208	33.7%
2032	8,036	6,413	25.3%	8,330	6,206	34.2%
2033	8,068	6,411	25.8%	7,724	6,205	24.5%
2034	7,460	6,408	16.4%	8,021	6,204	29.3%
2035	7,779	6,405	21.5%	8,902	6,202	43.5%
2036	8,677	6,402	35.5%	8,400	6,201	35.5%
2037	8,173	6,399	27.7%	8,831	6,200	42.4%
2038	8,602	6,397	34.5%	8,036	6,199	29.6%
2039	7,866	6,394	23.0%	9,348	6,197	50.8%
2040	9,200	6,391	44.0%	8,296	6,196	33.9%

Table B2. Standalone Capacity Addition (MW)

	CC	CT Gas	Storage	Utility Solar	Wind
2025					
2026					
2027				100	
2028	484			200	
2029	484			100	
2030					
2031					
2032					
2033				100	
2034		400		250	
2035	484			250	
2036	800		100	400	
2037		200	200	250	100
2038		200	200	250	
2039		200	200	250	
2040	968	200	200		

Table B3. Standalone Capacity Retirements (MW)

	Coal	CT Gas
2025	300	23
2026		
2027		
2028	709	
2029		
2030		
2031		
2032		
2033		
2034	969	121
2035		242
2036		121
2037	950	
2038		
2039	868	292
2040		

RTO Cases

Table B4. RTO Capacity Expansion and Reserve Margins

Year	Effective Summer UCAP (MW)	Peak Summer Demand (MW)	FPR	Effective Margin to FPR (%)
2025	7,136	6,303	6,331	13.2%
2026	7,136	6,308	6,336	13.1%
2027	7,135	6,427	6,456	11.0%
2028	7,074	6,425	6,453	10.1%
2029	7,110	6,422	6,450	10.7%
2030	7,098	6,419	6,448	10.6%
2031	7,093	6,416	6,445	10.6%
2032	7,089	6,413	6,442	10.5%
2033	7,121	6,411	6,439	11.1%
2034	7,123	6,408	6,436	11.2%
2035	7,092	6,405	6,433	10.7%
2036	7,396	6,402	6,431	15.5%
2037	7,137	6,399	6,428	11.5%
2038	7,369	6,397	6,425	15.2%
2039	7,190	6,394	6,422	12.4%
2040	7,356	6,391	6,419	15.1%

Table B5. RTO Capacity Addition (MW)

	CC	CT Gas	Storage	Utility Solar	Wind
2025					
2026					
2027					
2028	484			300	
2029				100	
2030					
2031					
2032					
2033				100	
2034	484	500		250	
2035			100	350	
2036	400			100	
2037		400	200	250	100
2038			200	250	
2039	484	400		250	
2040			200		

Table B6. RTO Capacity Retirements (MW)

	Coal	CT Gas
2025	300	23
2026		
2027		
2028	709	
2029		
2030		
2031		
2032		
2033		
2034	969	121
2035		242
2036		121
2037	950	
2038		
2039	868	292
2040		

APPENDIX C: PRODUCTION COSTS

Standalone Cases

Table C1. Baseline (Case 1) SA Production Costs

Year	Load (MWh)	Generation (MWh)	Generator Costs ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost
2025	33,050,200	33,116,428	$977.19	14,435	80,663	$1.65	$3.18	$976
2026	33,155,652	33,191,293	$936.40	12,556	48,197	$3.02	$1.79	$938
2027	34,025,754	34,059,264	$936.76	14,901	48,411	$3.74	$1.76	$939
2028	34,075,501	34,412,764	$815.32	12,309	351,273	$25.11	$11.74	$829
2029	33,920,099	34,701,367	$710.61	5,431	786,699	$0.43	$25.02	$686
2030	33,808,022	34,901,772	$712.48	4,801	1,098,550	$0.38	$34.18	$679
2031	33,768,873	35,103,821	$718.26	6,832	1,341,781	$0.59	$41.71	$677
2032	33,827,370	35,342,777	$724.04	5,909	1,521,362	$3.07	$47.66	$679
2033	33,717,105	35,128,457	$711.65	8,527	1,420,228	$12.17	$45.97	$678
2034	33,675,259	35,502,909	$645.43	4,382	1,832,032	$0.95	$54.46	$592
2035	33,675,950	35,908,564	$547.21	1,471	2,234,085	$0.13	$59.73	$488
2036	33,792,305	36,259,921	$423.20	141	2,467,756	$0.01	$55.09	$368
2037	33,709,835	36,219,410	$374.08	0	2,509,576	$0.00	$50.47	$324
2038	33,753,359	36,315,816	$350.65	0	2,562,456	$0.00	$46.82	$304
2039	33,754,477	36,286,804	$336.05	308	2,532,636	$0.03	$44.32	$292
2040	33,870,433	36,499,741	$303.92	0	2,629,308	$0.00	$27.36	$277

Table C2. CO_2 Regulated (Case 2) SA Production Costs

Year	Load (MWh)	Generation (MWh)	Generator Costs ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost
2025	33,050,200	33,045,701	$1,405	12,075	7,576	$1.02	$0.42	$1,406
2026	33,155,652	33,140,300	$1,391	21,165	5,814	$3.89	$0.30	$1,395
2027	34,025,754	34,007,079	$1,419	19,528	852	$4.90	$0.04	$1,424
2028	34,075,501	34,087,419	$1,231	17,121	30,737	$25.63	$1.58	$1,255
2029	33,920,099	34,030,336	$1,053	13,213	123,450	$1.16	$6.15	$1,048
2030	33,808,022	33,997,389	$1,070	11,160	200,527	$0.98	$10.09	$1,061
2031	33,768,873	34,024,679	$1,088	13,651	269,502	$4.42	$14.04	$1,078
2032	33,827,370	34,119,985	$1,114	11,728	304,343	$1.39	$16.02	$1,099
2033	33,717,105	33,921,411	$1,092	23,843	228,150	$6.12	$12.60	$1,085
2034	33,675,259	34,112,350	$953	25,152	462,243	$6.22	$22.83	$936
2035	33,675,950	34,602,900	$773	16,799	943,749	$1.61	$39.60	$735
2036	33,792,305	35,548,211	$566	7,712	1,763,617	$0.78	$51.36	$515
2037	33,709,835	35,753,545	$497	3,033	2,046,744	$0.30	$50.32	$447
2038	33,753,359	36,026,741	$475	1,411	2,274,793	$0.14	$49.61	$425
2039	33,754,477	36,145,119	$446	2,506	2,393,148	$0.54	$47.15	$400
2040	33,870,433	36,495,786	$410	-	2,625,353	$0.00	$27.16	$382

Table C3. High Fuel Prices (Case 3) SA Production Costs

Year	Load (MWh)	Generation (MWh)	Generator Costs ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost
2025	33,050,200	33,033,587	$1,332	17,630	1,018	$1.95	$0.05	$1,334
2026	33,155,652	33,137,423	$1,381	18,229	-	$3.73	$0.00	$1,385
2027	34,025,754	33,981,673	$1,451	44,068	-	$14.84	$0.00	$1,466
2028	33,345,958	33,320,397	$1,240	23,860	-	$27.82	$0.00	$1,268
2029	33,920,099	33,904,092	$1,083	23,672	7,665	$2.22	$0.40	$1,084
2030	33,808,022	33,794,248	$1,107	26,625	12,851	$2.18	$0.69	$1,108
2031	33,768,873	33,742,664	$1,131	34,979	8,770	$3.56	$0.49	$1,134
2032	33,827,370	33,824,676	$1,163	24,534	21,885	$5.00	$1.22	$1,167
2033	33,717,105	33,672,275	$1,152	52,525	8,044	$17.83	$0.45	$1,169
2034	33,675,259	33,682,054	$984	53,901	60,696	$7.03	$2.32	$989
2035	33,675,950	33,995,936	$789	37,426	357,413	$3.33	$11.57	$780
2036	33,792,305	34,997,571	$571	25,011	1,230,276	$2.53	$27.19	$546
2037	33,709,835	35,319,979	$499	9,301	1,619,445	$1.12	$31.48	$469
2038	33,753,359	35,774,564	$473	5,205	2,026,410	$0.46	$37.15	$437
2039	33,754,477	35,932,932	$453	11,417	2,189,873	$3.19	$37.93	$418
2040	33,870,433	36,472,866	$426	839	2,603,272	$0.07	$26.99	$399

Table C4. High Fuel Prices + CO_2 Regulated (Case 4) SA Production Costs

Year	Load (MWh)	Generation (MWh)	Generator Costs ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost
2025	33,050,200	33,027,217	1,753	22,983	-	$1.90	$0.00	$1,754
2026	33,155,652	33,135,714	1,825	19,938	-	$4.05	$0.00	$1,829
2027	34,025,754	33,936,431	1,916	89,323	-	$19.38	$0.00	$1,935
2028	34,075,501	34,006,649	1,664	67,151	-	$41.61	$0.00	$1,706
2029	33,920,099	33,876,251	1,406	43,931	82	$4.34	$0.00	$1,410
2030	33,808,022	33,750,825	1,446	58,467	1,270	$9.99	$0.07	$1,456
2031	33,768,873	33,706,404	1,484	62,761	337	$15.17	$0.02	$1,499
2032	33,827,370	33,730,180	1,535	97,213	22	$17.12	$0.00	$1,552
2033	33,717,105	33,514,550	1,510	203,306	955	$57.99	$0.04	$1,568
2034	33,675,259	33,541,976	1,268	180,750	47,567	$39.62	$1.97	$1,306
2035	33,675,950	33,904,424	988	108,731	337,300	$21.72	$11.83	$998
2036	33,792,305	34,894,926	696	47,248	1,149,868	$6.51	$25.86	$677
2037	33,709,835	35,273,304	614	28,500	1,591,969	$5.02	$32.07	$587
2038	33,753,359	35,642,572	591	27,588	1,916,801	$2.58	$36.86	$557
2039	33,107,275	35,225,667	551	21,340	2,139,732	$8.17	$38.50	$520
2040	33,220,731	35,780,859	518	646	2,560,773	$0.07	$26.03	$492

Guidehouse

Energy Markets Analysis

RTO Cases

Table C5. Baseline (Case 1) RTO Production Costs

Year	LMPs ($/MWh)	Load (MWh)	Cost to Serve Load ($mil)	Generation (MWh)	Generator Revenue ($mil)	Generator Costs ($mil)	Generator Margin ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost ($mil)
						Production Costs						
			C * D				G-H					E-I
2025	$38.48	33,050,200	$1,272	34,496,711	$1,317	$1,019	$298	506,659	1,953,170	$19.75	$72.73	$974
2026	$36.94	33,155,652	$1,225	35,080,117	$1,288	$992	$296	296,008	2,220,473	$12.50	$78.82	$929
2027	$38.03	34,025,754	$1,294	34,989,561	$1,318	$969	$348	909,217	1,873,023	$37.86	$66.78	$946
2028	$36.08	34,075,501	$1,229	36,130,379	$1,291	$862	$429	268,802	2,323,680	$12.15	$78.94	$800
2029	$35.55	33,920,099	$1,206	36,185,124	$1,277	$846	$431	149,169	2,414,194	$7.11	$81.57	$775
2030	$34.72	33,233,481	$1,154	35,594,820	$1,230	$824	$405	81,125	2,442,465	$3.72	$81.40	$748
2031	$36.36	33,768,873	$1,228	36,094,634	$1,304	$840	$464	144,101	2,469,862	$6.92	$84.66	$764
2032	$36.85	33,827,370	$1,246	36,339,562	$1,333	$848	$484	43,373	2,555,565	$2.16	$89.73	$762
2033	$39.16	33,717,105	$1,320	36,218,402	$1,412	$848	$564	36,978	2,538,275	$2.05	$95.28	$757
2034	$31.79	33,675,259	$1,071	36,275,068	$1,147	$657	$490	4,547	2,604,356	$0.23	$80.12	$581
2035	$30.16	33,675,950	$1,016	36,288,089	$1,087	$620	$467	1,610	2,613,749	$0.08	$77.04	$549
2036	$30.57	33,792,305	$1,033	36,408,711	$1,103	$554	$549	2,291	2,618,697	$0.08	$77.59	$484
2037	$26.79	33,709,835	$903	36,325,556	$963	$473	$490	1,885	2,617,606	$0.09	$67.93	$414
2038	$25.56	33,753,359	$863	36,375,902	$919	$450	$469	417	2,622,959	$0.02	$65.47	$394
2039	$20.80	33,754,477	$702	36,372,163	$746	$372	$374	4,736	2,622,423	$0.26	$52.44	$328
2040	$21.97	33,870,433	$744	36,444,386	$786	$383	$403	23,572	2,597,525	$1.37	$53.72	$341

Table C6. CO_2 Regulated (Case 2) RTO Production Costs

	Production Costs											
Year	LMPs ($/MWh)	Load (MWh)	Cost to Serve Load ($mil)	Generation (MWh)	Generator Revenue ($mil)	Generator Costs ($mil)	Generator Margin ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost ($mil)
			C * D				G-H					E-I
2025	$50.15	33,050,200	$1,658	25,515,162	$1,302	$1,045	$257	7,909,899	374,862	$372	$20	$1,400
2026	$49.49	33,155,652	$1,641	27,746,814	$1,391	$1,147	$244	5,988,116	579,278	$278	$30	$1,397
2027	$50.22	34,025,754	$1,709	29,362,253	$1,490	$1,223	$267	5,233,210	569,709	$246	$30	$1,442
2028	$50.50	34,075,501	$1,721	33,234,763	$1,678	$1,190	$488	2,107,476	1,266,739	$103	$64	$1,232
2029	$51.15	33,920,099	$1,735	33,851,802	$1,731	$1,209	$522	1,505,225	1,436,927	$74	$73	$1,213
2030	$51.57	33,808,022	$1,743	34,513,000	$1,779	$1,258	$521	1,023,661	1,728,640	$50	$89	$1,222
2031	$53.43	33,768,873	$1,804	34,783,742	$1,855	$1,298	$557	805,178	1,820,047	$41	$96	$1,247
2032	$54.64	33,827,370	$1,848	34,829,277	$1,900	$1,323	$577	842,518	1,844,425	$44	$100	$1,272
2033	$56.73	33,717,105	$1,913	33,931,519	$1,922	$1,272	$650	1,320,491	1,534,905	$71	$87	$1,263
2034	$52.58	33,675,259	$1,771	35,778,986	$1,868	$999	$869	191,030	2,294,757	$10	$118	$901
2035	$51.92	33,675,950	$1,748	35,893,627	$1,848	$956	$892	129,102	2,346,779	$7	$119	$856
2036	$50.51	33,792,305	$1,707	35,924,189	$1,793	$821	$972	200,983	2,332,866	$11	$113	$735
2037	$43.33	33,709,835	$1,461	36,123,913	$1,542	$668	$874	69,470	2,483,548	$4	$102	$587
2038	$42.48	33,753,359	$1,434	36,119,236	$1,509	$636	$872	89,732	2,455,608	$5	$98	$561
2039	$27.89	33,754,477	$941	36,263,086	$987	$488	$499	47,725	2,556,334	$3	$65	$442
2040	$27.73	33,870,433	$939	36,344,125	$975	$504	$471	83,930	2,557,621	$6	$64	$468

Table C7. High Fuel Prices (Case 3) RTO Production Costs

	Production Costs											
Year	LMPs ($/MWh)	Load (MWh)	Cost to Serve Load ($mil)	Generation (MWh)	Generator Revenue ($mil)	Generator Costs ($mil)	Generator Margin ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost ($mil)
			C * D				G-H					E-I
2025	$47.22	33,050,200	$1,561	19,278,483	$954	$724	$230	14,006,102	234,385	$613.09	$13.04	$1,330
2026	$48.31	33,155,652	$1,602	18,489,389	$935	$724	$211	14,870,552	204,289	$675.43	$11.52	$1,390
2027	$49.75	34,025,754	$1,693	17,813,063	$928	$715	$214	16,339,538	126,846	$767.71	$7.64	$1,479
2028	$51.49	34,075,501	$1,754	24,761,822	$1,306	$838	$468	9,719,505	405,825	$466.03	$23.42	$1,286
2029	$52.90	33,920,099	$1,794	25,418,473	$1,381	$863	$517	8,945,351	443,724	$435.78	$26.24	$1,277
2030	$54.32	33,808,022	$1,836	26,184,550	$1,459	$928	$531	8,167,847	544,375	$406.98	$32.66	$1,305
2031	$56.07	33,768,873	$1,893	27,020,382	$1,550	$996	$554	7,402,977	654,486	$379.49	$39.76	$1,340
2032	$57.57	33,827,370	$1,948	27,000,833	$1,597	$1,026	$571	7,490,568	664,031	$389.65	$41.74	$1,377
2033	$58.89	33,717,105	$1,986	26,278,554	$1,589	$976	$614	7,891,212	452,661	$421.93	$30.05	$1,372
2034	$57.49	33,675,259	$1,936	32,130,700	$1,853	$883	$970	2,631,189	1,086,631	$140.52	$63.60	$966
2035	$56.92	33,675,950	$1,917	32,830,031	$1,867	$869	$997	2,184,612	1,338,692	$117.01	$75.60	$919
2036	$55.18	33,792,305	$1,865	34,217,667	$1,872	$784	$1,088	1,241,154	1,666,515	$68.98	$86.11	$776
2037	$47.12	33,709,835	$1,589	35,315,338	$1,639	$661	$978	494,676	2,100,179	$27.97	$88.93	$611
2038	$45.34	33,753,359	$1,531	35,509,574	$1,584	$640	$944	392,290	2,148,505	$22.24	$87.62	$586
2039	$28.82	33,754,477	$973	36,172,321	$1,021	$507	$515	93,974	2,511,818	$6.10	$64.07	$458
2040	$29.11	33,870,433	$986	36,318,274	$1,033	$518	$515	84,104	2,531,945	$5.73	$66.14	$472

Guidehouse

Energy Markets Analysis

Table C8. High Fuel Prices + CO_2 Regulated (Case 4) RTO Production Costs

Production Costs												
Year	LMPs ($/MWh)	Load (MWh)	Cost to Serve Load ($mil)	Generation (MWh)	Generator Revenue ($mil)	Generator Costs ($mil)	Generator Margin ($mil)	Imports (MWh)	Exports (MWh)	Imports Cost ($mil)	Exports Revenue ($mil)	Total Production Cost ($mil)
			C * D				G-H					E-I
2025	$54.59	33,050,200	$1,804	12,435,029	$701	$545	$156	20,649,528	34,357	$1,102.92	$2.50	$1,648
2026	$55.79	33,155,652	$1,850	11,595,525	$664	$524	$140	21,576,000	15,873	$1,185.36	$1.18	$1,710
2027	$57.50	34,025,754	$1,956	11,731,147	$691	$551	$140	22,301,204	6,597	$1,263.71	$0.52	$1,816
2028	$59.71	34,075,501	$2,035	17,849,270	$1,085	$652	$433	16,280,288	54,056	$949.27	$4.12	$1,602
2029	$61.57	33,920,100	$2,088	18,792,072	$1,180	$690	$490	15,203,046	75,019	$909.02	$5.82	$1,598
2030	$63.40	33,808,022	$2,144	19,051,106	$1,238	$741	$497	14,871,748	114,832	$910.16	$8.94	$1,646
2031	$66.17	33,768,873	$2,235	19,565,445	$1,324	$802	$522	14,332,390	128,962	$914.01	$10.27	$1,712
2032	$68.20	33,827,370	$2,307	19,576,841	$1,348	$816	$531	14,362,411	111,881	$940.03	$9.30	$1,776
2033	$69.15	33,717,105	$2,331	19,299,481	$1,362	$785	$577	14,471,695	54,072	$964.85	$4.64	$1,754
2034	$69.65	33,675,259	$2,346	27,703,432	$1,931	$823	$1,109	6,280,917	309,090	$424.24	$22.49	$1,237
2035	$70.83	33,675,950	$2,385	29,023,042	$2,054	$849	$1,205	5,207,502	554,594	$355.82	$39.46	$1,180
2036	$69.05	33,792,305	$2,333	31,357,488	$2,134	$805	$1,329	3,405,913	971,096	$241.45	$59.07	$1,005
2037	$59.72	33,709,835	$2,013	33,641,183	$1,954	$721	$1,233	1,626,468	1,557,817	$115.68	$75.85	$781
2038	$57.84	33,753,359	$1,952	33,998,187	$1,907	$705	$1,202	1,454,959	1,699,786	$104.00	$80.79	$751
2039	$35.11	33,754,477	$1,185	35,880,058	$1,214	$599	$616	241,337	2,366,918	$18.26	$67.27	$570
2040	$33.91	33,870,433	$1,148	36,039,109	$1,169	$623	$546	235,459	2,404,135	$18.56	$66.13	$603

APPENDIX D: GENERATION

Generation by Unit Type (MW)

Table D1. Baseline (Case 1) SA - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	1,153,165	4,988,572		19297	356,900		25,338,860
2026	866,959	4,862,165		19240	356,899		26,438,937
2027	1,291,679	4,821,181		455303	356,900		26,334,204
2028	950,590	8,805,967		1330908	357,889		22,305,398
2029	474,670	13,117,867		1756684	356,900		18,455,464
2030	477,327	12,805,144		1760777	356,900		18,965,497
2031	675,049	12,844,416		1761186	356,900		18,927,305
2032	703,658	12,686,712		1768648	357,889		19,303,439
2033	1,055,717	12,875,572		2194394	356,900		18,128,800
2034	4,195,303	12,758,164		3291597	356,900		14,382,082
2035	3,559,880	15,919,234		4362742	356,900	0	11,201,411
2036	2,726,054	20,666,335	0	5516739	357,889	182,629	6,518,077
2037	3,253,065	19,664,614	792,392	6574905	356,900	491,275	5,161,880
2038	3,678,013	18,909,047	794,091	7675736	356,900	751,778	4,527,490
2039	4,100,952	17,948,711	794,058	8743892	356,900	1,023,307	4,018,690
2040	1,997,122	20,330,077	798,501	8739245	357,001	882,407	3,925,855

Table D2. CO_2 Regulated (Case 2) SA - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	1,504,867	5,312,328		19297	356,900		23,984,080
2026	1,122,920	5,352,998		19240	356,900		24,738,257
2027	1,509,204	5,322,209		455303	356,900		24,832,550
2028	1,055,428	9,443,104		1330908	357,889		20,679,549
2029	640,237	13,796,428		1756684	356,900		16,645,134
2030	672,185	13,448,882		1760777	356,899		16,999,223
2031	805,653	13,431,065		1761186	356,899		16,990,983
2032	871,098	13,270,289		1768648	357,889		17,166,989
2033	1,369,310	13,479,190		2194394	356,899		15,762,006
2034	4,450,276	13,438,378		3291597	356,900		11,917,104
2035	4,011,075	16,889,286		4362742	356,900	0	8,439,524
2036	2,924,787	21,109,075	0	5516710	357,889	190,866	5,157,928
2037	3,450,967	19,691,429	791,483	6572576	356,900	515,442	4,470,964
2038	3,817,129	18,847,238	794,144	7675271	356,900	782,816	4,162,712
2039	3,935,671	18,098,047	794,409	8743332	356,900	1,050,249	3,877,783
2040	1,886,233	20,550,484	800,007	8748870	353,450	906,201	3,814,836

Table D3. High Fuel Prices (Case 3) SA - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	2,958,721	5,331,160		19297	356,900		22,475,013
2026	2,297,795	5,373,589		19240	356,899		23,194,790
2027	2,542,236	5,334,773		455303	356,899		23,392,785
2028	1,525,452	9,282,456		1301031	351,126		19,042,458
2029	945,681	13,832,162		1756684	356,900		15,213,098
2030	861,325	13,464,121		1760777	356,900		15,589,675
2031	877,530	13,461,360		1761186	356,900		15,562,248
2032	731,555	13,285,385		1768648	357,889		15,956,437
2033	1,173,666	13,400,599		2194394	356,900		14,786,798
2034	4,182,659	13,289,285		3291597	356,900		10,895,745
2035	3,762,028	16,374,355		4362742	356,899	0	7,760,761
2036	2,792,596	20,550,119	0	5516739	357,889	197,063	4,966,073
2037	3,272,652	19,375,541	792,725	6576612	356,900	512,709	4,350,371
2038	3,714,934	18,726,429	794,945	7677058	356,900	788,856	4,064,950
2039	4,037,302	17,748,595	793,837	8744434	356,740	1,057,295	3,846,675
2040	1,992,549	20,337,226	799,509	8741834	357,001	885,688	3,899,386

Table D4. High Fuel Price + CO_2 Reg (Case 4 SA) - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	4,612,437	5,334,981		19297	356,900		20,795,889
2026	3,607,748	5,374,595		19240	356,900		21,869,324
2027	3,886,198	5,335,902		455303	356,900		21,996,397
2028	2,573,399	9,486,074		1330908	357,889		18,351,162
2029	1,835,685	13,895,568		1756684	356,899		14,140,465
2030	1,642,872	13,512,256		1760777	356,900		14,588,824
2031	1,603,468	13,486,725		1761186	356,900		14,618,322
2032	1,638,373	13,315,559		1768648	357,889		14,765,154
2033	1,894,697	13,516,070		2194394	356,900		13,664,183
2034	4,748,554	13,388,583		3291597	356,900		9,883,651
2035	4,132,413	16,558,812		4362742	356,900	0	6,822,756
2036	2,817,052	20,561,795	0	5516710	357,889	192,798	4,583,138
2037	3,385,036	19,204,619	791,746	6572608	356,900	511,788	4,197,964
2038	3,759,918	18,446,331	794,900	7675965	356,900	782,123	4,011,791
2039	3,850,661	17,528,474	776,957	8549361	347,932	1,034,728	3,724,817
2040	1,860,959	20,150,827	786,646	8560459	348,124	888,843	3,736,412

Table D5. Baseline (Case 1) RTO - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	918,687	5,087,262		19297	356,900		26,753,928
2026	694,948	4,970,139		19240	356,899		28,360,604
2027	939,921	4,982,032		19280	356,900		27,915,166
2028	797,983	8,973,291		1330908	357,889		24,050,548
2029	865,898	9,307,512		1756684	356,900		23,318,272
2030	814,874	8,794,655		1725053	349,144		23,385,247
2031	1,241,735	8,949,884		1761186	356,900		23,237,125
2032	1,486,289	8,756,127		1768648	357,889		23,425,526
2033	1,993,350	9,071,468		2194394	356,900		22,049,126
2034	4,989,895	12,781,328		3291597	356,900	0	14,333,911
2035	4,616,815	12,517,929		4593087	356,900	160,511	13,709,620
2036	4,669,551	15,521,555	0	5053272	357,889	168,732	10,317,289
2037	7,012,208	14,552,309	793,090	6120500	356,900	462,264	7,063,736
2038	6,491,150	14,266,408	796,953	7224931	356,899	748,331	6,859,350
2039	6,379,536	15,932,023	795,336	8292481	356,868	854,606	4,258,361
2040	6,262,818	16,173,444	802,520	8313698	357,889	1,059,963	4,195,053

Table D6. CO_2 Regulated (Case 2) RTO - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	996,710	5,288,395		19297	356,899		17,264,323
2026	949,835	5,295,502		19240	356,899		19,997,951
2027	1,049,226	5,261,729		19280	356,899		21,499,466
2028	791,693	9,453,127		1330908	357,889		20,320,687
2029	810,433	9,812,201		1756684	356,900		20,181,185
2030	879,873	9,457,551		1760777	356,900		21,190,983
2031	1,175,648	9,401,502		1761186	356,900		21,190,815
2032	1,290,300	9,286,761		1768648	357,889		21,279,226
2033	1,811,504	9,433,518		2194394	356,900		19,221,133
2034	5,079,393	13,469,736		3291597	356,900	0	12,799,777
2035	4,995,955	13,332,789		4593087	356,900	140,440	11,845,949
2036	5,048,200	15,983,056	0	5053272	357,889	159,995	8,771,408
2037	7,250,601	14,993,342	793,090	6120500	356,900	492,944	6,051,674
2038	6,934,667	14,645,302	796,953	7224931	356,900	776,527	5,635,066
2039	6,471,173	16,031,159	795,478	8294376	356,899	927,873	3,953,021
2040	6,543,944	16,058,280	802,392	8313623	357,889	1,190,430	3,961,006

Table D7. High Fuel Prices (Case 3) RTO - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	1,417,889	4,992,472		19297	355,983		1,417,889
2026	1,458,335	4,757,695		19240	356,899		1,458,335
2027	1,254,000	4,732,231		19280	354,209		1,254,000
2028	1,328,146	9,065,567		1330908	357,889		1,328,146
2029	1,204,432	9,467,453		1756684	356,899		1,204,432
2030	1,247,088	9,108,830		1760777	356,899		1,247,088
2031	1,265,791	9,117,207		1761186	356,899		1,265,791
2032	1,344,897	8,847,255		1768648	357,889		1,344,897
2033	1,390,299	9,100,985		2194394	356,899		1,390,299
2034	4,895,888	13,342,595		3291597	356,899	0	4,895,888
2035	4,606,496	13,207,710		4593087	356,900	148,786	4,606,496
2036	4,526,808	16,082,417	0	5053272	357,889	164,635	4,526,808
2037	6,955,432	14,954,523	793,090	6120500	356,900	492,057	6,955,432
2038	6,569,869	14,642,520	796,953	7224931	356,899	770,866	6,569,869
2039	6,444,878	15,789,559	795,420	8292350	356,899	931,697	6,444,878
2040	6,492,195	16,036,156	802,520	8313698	357,889	1,190,655	6,492,195

Table D8. High Fuel Prices + CO_2 Regulated (Case 4) RTO - Generation by Unit Type (MW)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	519,894	5,013,533		19297	345,194		5,583,006
2026	488,387	4,591,145		19240	348,456		5,289,284
2027	513,346	4,673,773		19280	348,815		5,337,193
2028	691,148	8,794,491		1330908	357,889		5,867,382
2029	821,190	9,224,135		1756684	356,899		5,741,870
2030	887,455	8,772,285		1760777	356,899		6,382,393
2031	1,123,003	8,837,752		1761186	356,899		6,563,541
2032	1,121,730	8,548,697		1732843	352,514		6,619,519
2033	927,410	8,784,506		2194394	356,899		6,126,532
2034	4,854,679	12,933,947		3291597	356,899	0	5,415,578
2035	4,859,509	12,830,307		4593087	356,899	151,728	5,590,746
2036	4,663,323	15,537,592	0	5053272	357,889	160,505	5,007,510
2037	7,022,735	14,476,103	793,090	6120500	356,899	486,856	4,317,356
2038	6,769,271	14,230,475	796,953	7224931	356,899	767,864	4,144,915
2039	6,393,891	15,909,520	795,605	8294268	356,899	937,391	3,760,385
2040	6,529,907	15,890,790	802,520	8313496	357,889	1,192,515	3,824,853

Generation by Unit Type (% of Annual Generation)

Table D9. Baseline (Case 1) SA - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	3.6%	15.7%	0.0%	0.1%	1.1%	0.0%	79.5%
2026	2.7%	14.9%	0.0%	0.1%	1.1%	0.0%	81.2%
2027	3.9%	14.5%	0.0%	1.4%	1.1%	0.0%	79.2%
2028	2.8%	26.1%	0.0%	3.9%	1.1%	0.0%	66.1%
2029	1.4%	38.4%	0.0%	5.1%	1.0%	0.0%	54.0%
2030	1.4%	37.3%	0.0%	5.1%	1.0%	0.0%	55.2%
2031	2.0%	37.2%	0.0%	5.1%	1.0%	0.0%	54.8%
2032	2.0%	36.4%	0.0%	5.1%	1.0%	0.0%	55.4%
2033	3.1%	37.2%	0.0%	6.3%	1.0%	0.0%	52.4%
2034	12.0%	36.5%	0.0%	9.4%	1.0%	0.0%	41.1%
2035	10.1%	45.0%	0.0%	12.3%	1.0%	0.0%	31.6%
2036	7.6%	57.5%	0.0%	15.3%	1.0%	0.5%	18.1%
2037	9.0%	54.2%	2.2%	18.1%	1.0%	1.4%	14.2%
2038	10.0%	51.5%	2.2%	20.9%	1.0%	2.0%	12.3%
2039	11.1%	48.5%	2.1%	23.6%	1.0%	2.8%	10.9%
2040	5.4%	54.9%	2.2%	23.6%	1.0%	2.4%	10.6%

Table D10. CO_2 Regulated (Case 2) SA - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	4.8%	17.0%	0.0%	0.1%	1.1%	0.0%	76.9%
2026	3.6%	16.9%	0.0%	0.1%	1.1%	0.0%	78.3%
2027	4.6%	16.4%	0.0%	1.4%	1.1%	0.0%	76.5%
2028	3.2%	28.7%	0.0%	4.0%	1.1%	0.0%	62.9%
2029	1.9%	41.6%	0.0%	5.3%	1.1%	0.0%	50.1%
2030	2.0%	40.5%	0.0%	5.3%	1.1%	0.0%	51.1%
2031	2.4%	40.3%	0.0%	5.3%	1.1%	0.0%	51.0%
2032	2.6%	39.7%	0.0%	5.3%	1.1%	0.0%	51.3%
2033	4.1%	40.6%	0.0%	6.6%	1.1%	0.0%	47.5%
2034	13.3%	40.2%	0.0%	9.8%	1.1%	0.0%	35.6%
2035	11.8%	49.6%	0.0%	12.8%	1.0%	0.0%	24.8%
2036	8.3%	59.9%	0.0%	15.6%	1.0%	0.5%	14.6%
2037	9.6%	54.9%	2.2%	18.3%	1.0%	1.4%	12.5%
2038	10.5%	51.7%	2.2%	21.1%	1.0%	2.1%	11.4%
2039	10.7%	49.1%	2.2%	23.7%	1.0%	2.8%	10.5%
2040	5.1%	55.5%	2.2%	23.6%	1.0%	2.4%	10.3%

Table D11. High Fuel Prices (Case 3) SA - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	9.5%	17.1%	0.0%	0.1%	1.1%	0.0%	72.2%
2026	7.4%	17.2%	0.0%	0.1%	1.1%	0.0%	74.2%
2027	7.9%	16.6%	0.0%	1.4%	1.1%	0.0%	72.9%
2028	4.8%	29.5%	0.0%	4.1%	1.1%	0.0%	60.4%
2029	2.9%	43.1%	0.0%	5.5%	1.1%	0.0%	47.4%
2030	2.7%	42.0%	0.0%	5.5%	1.1%	0.0%	48.7%
2031	2.7%	42.0%	0.0%	5.5%	1.1%	0.0%	48.6%
2032	2.3%	41.4%	0.0%	5.5%	1.1%	0.0%	49.7%
2033	3.7%	42.0%	0.0%	6.9%	1.1%	0.0%	46.3%
2034	13.1%	41.5%	0.0%	10.3%	1.1%	0.0%	34.0%
2035	11.5%	50.2%	0.0%	13.4%	1.1%	0.0%	23.8%
2036	8.1%	59.8%	0.0%	16.0%	1.0%	0.6%	14.4%
2037	9.3%	55.0%	2.2%	18.7%	1.0%	1.5%	12.3%
2038	10.3%	51.8%	2.2%	21.3%	1.0%	2.2%	11.3%
2039	11.0%	48.5%	2.2%	23.9%	1.0%	2.9%	10.5%
2040	5.4%	54.9%	2.2%	23.6%	1.0%	2.4%	10.5%

Table D12. High Fuel Prices + CO_2 Regulated (Case 4 SA) - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	14.8%	17.1%	0.0%	0.1%	1.1%	0.0%	66.8%
2026	11.6%	17.2%	0.0%	0.1%	1.1%	0.0%	70.0%
2027	12.1%	16.7%	0.0%	1.4%	1.1%	0.0%	68.7%
2028	8.0%	29.6%	0.0%	4.1%	1.1%	0.0%	57.2%
2029	5.7%	43.4%	0.0%	5.5%	1.1%	0.0%	44.2%
2030	5.2%	42.4%	0.0%	5.5%	1.1%	0.0%	45.8%
2031	5.0%	42.4%	0.0%	5.5%	1.1%	0.0%	45.9%
2032	5.1%	41.8%	0.0%	5.6%	1.1%	0.0%	46.4%
2033	6.0%	42.7%	0.0%	6.9%	1.1%	0.0%	43.2%
2034	15.0%	42.3%	0.0%	10.4%	1.1%	0.0%	31.2%
2035	12.8%	51.4%	0.0%	13.5%	1.1%	0.0%	21.2%
2036	8.3%	60.4%	0.0%	16.2%	1.1%	0.6%	13.5%
2037	9.7%	54.8%	2.3%	18.8%	1.0%	1.5%	12.0%
2038	10.5%	51.5%	2.2%	21.4%	1.0%	2.2%	11.2%
2039	10.8%	48.9%	2.2%	23.9%	1.0%	2.9%	10.4%
2040	5.1%	55.5%	2.2%	23.6%	1.0%	2.4%	10.3%

Table D13. Baseline (Case 1) RTO - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	2.8%	15.4%	0.0%	0.1%	1.1%	0.0%	80.7%
2026	2.0%	14.4%	0.0%	0.1%	1.0%	0.0%	82.4%
2027	2.7%	14.6%	0.0%	0.1%	1.0%	0.0%	81.6%
2028	2.2%	25.3%	0.0%	3.7%	1.0%	0.0%	67.7%
2029	2.4%	26.1%	0.0%	4.9%	1.0%	0.0%	65.5%
2030	2.3%	25.1%	0.0%	4.9%	1.0%	0.0%	66.7%
2031	3.5%	25.2%	0.0%	5.0%	1.0%	0.0%	65.4%
2032	4.2%	24.5%	0.0%	4.9%	1.0%	0.0%	65.4%
2033	5.6%	25.4%	0.0%	6.2%	1.0%	0.0%	61.8%
2034	14.0%	35.7%	0.0%	9.2%	1.0%	0.0%	40.1%
2035	12.8%	34.8%	0.0%	12.8%	1.0%	0.4%	38.1%
2036	12.9%	43.0%	0.0%	14.0%	1.0%	0.5%	28.6%
2037	19.3%	40.0%	2.2%	16.8%	1.0%	1.3%	19.4%
2038	17.7%	38.8%	2.2%	19.7%	1.0%	2.0%	18.7%
2039	17.3%	43.2%	2.2%	22.5%	1.0%	2.3%	11.5%
2040	16.9%	43.5%	2.2%	22.4%	1.0%	2.9%	11.3%

Table D14. CO_2 Regulated (Case 2) RTO - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	4.2%	22.1%	0.0%	0.1%	1.5%	0.0%	72.2%
2026	3.6%	19.9%	0.0%	0.1%	1.3%	0.0%	75.1%
2027	3.7%	18.7%	0.0%	0.1%	1.3%	0.0%	76.3%
2028	2.5%	29.3%	0.0%	4.1%	1.1%	0.0%	63.0%
2029	2.5%	29.8%	0.0%	5.3%	1.1%	0.0%	61.3%
2030	2.6%	28.1%	0.0%	5.2%	1.1%	0.0%	63.0%
2031	3.5%	27.7%	0.0%	5.2%	1.1%	0.0%	62.5%
2032	3.8%	27.3%	0.0%	5.2%	1.1%	0.0%	62.6%
2033	5.5%	28.6%	0.0%	6.6%	1.1%	0.0%	58.2%
2034	14.5%	38.5%	0.0%	9.4%	1.0%	0.0%	36.6%
2035	14.2%	37.8%	0.0%	13.0%	1.0%	0.4%	33.6%
2036	14.3%	45.2%	0.0%	14.3%	1.0%	0.5%	24.8%
2037	20.1%	41.6%	2.2%	17.0%	1.0%	1.4%	16.8%
2038	19.1%	40.3%	2.2%	19.9%	1.0%	2.1%	15.5%
2039	17.6%	43.5%	2.2%	22.5%	1.0%	2.5%	10.7%
2040	17.6%	43.1%	2.2%	22.3%	1.0%	3.2%	10.6%

Table D15. High Fuel Prices (Case 3) RTO - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	7.9%	27.9%	0.0%	0.1%	2.0%	0.0%	62.1%
2026	8.4%	27.2%	0.0%	0.1%	2.0%	0.0%	62.2%
2027	7.5%	28.2%	0.0%	0.1%	2.1%	0.0%	62.1%
2028	5.6%	38.2%	0.0%	5.6%	1.5%	0.0%	49.1%
2029	4.9%	38.7%	0.0%	7.2%	1.5%	0.0%	47.7%
2030	4.9%	36.1%	0.0%	7.0%	1.4%	0.0%	50.6%
2031	4.9%	35.0%	0.0%	6.8%	1.4%	0.0%	52.0%
2032	5.2%	33.9%	0.0%	6.8%	1.4%	0.0%	52.7%
2033	5.5%	36.0%	0.0%	8.7%	1.4%	0.0%	48.5%
2034	15.6%	42.6%	0.0%	10.5%	1.1%	0.0%	30.1%
2035	14.3%	41.0%	0.0%	14.3%	1.1%	0.5%	28.8%
2036	13.5%	47.9%	0.0%	15.0%	1.1%	0.5%	22.1%
2037	19.7%	42.5%	2.3%	17.4%	1.0%	1.4%	15.8%
2038	18.4%	41.0%	2.2%	20.2%	1.0%	2.2%	15.0%
2039	17.5%	43.0%	2.2%	22.6%	1.0%	2.5%	11.3%
2040	17.5%	43.1%	2.2%	22.4%	1.0%	3.2%	10.7%

Table D16. High Fuel Prices + CO_2 Regulated (Case 4) RTO - Generation by Unit Type (%)

Year	IC/GT	CC	Wind	PV	Hydro	ES	Coal
2025	4.5%	43.7%	0.0%	0.2%	3.0%	0.0%	48.6%
2026	4.5%	42.8%	0.0%	0.2%	3.2%	0.0%	49.3%
2027	4.7%	42.9%	0.0%	0.2%	3.2%	0.0%	49.0%
2028	4.1%	51.6%	0.0%	7.8%	2.1%	0.0%	34.4%
2029	4.6%	51.5%	0.0%	9.8%	2.0%	0.0%	32.1%
2030	4.9%	48.3%	0.0%	9.7%	2.0%	0.0%	35.1%
2031	6.0%	47.4%	0.0%	9.4%	1.9%	0.0%	35.2%
2032	6.1%	46.5%	0.0%	9.4%	1.9%	0.0%	36.0%
2033	5.0%	47.8%	0.0%	11.9%	1.9%	0.0%	33.3%
2034	18.1%	48.2%	0.0%	12.3%	1.3%	0.0%	20.2%
2035	17.1%	45.2%	0.0%	16.2%	1.3%	0.5%	19.7%
2036	15.2%	50.5%	0.0%	16.4%	1.2%	0.5%	16.3%
2037	20.9%	43.1%	2.4%	18.2%	1.1%	1.5%	12.9%
2038	19.7%	41.5%	2.3%	21.1%	1.0%	2.2%	12.1%
2039	17.5%	43.6%	2.2%	22.8%	1.0%	2.6%	10.3%
2040	17.7%	43.1%	2.2%	22.5%	1.0%	3.2%	10.4%

APPENDIX E: EMISSIONS

Table E1. Emissions by Case (million short tons)

Year	Baseline Case 1 SA	CO_2 Regulated Case 2 SA	High Fuel Prices Case 3 SA	High Fuel Prices + CO_2 Regulated Case 4 SA	Baseline Case 1 RTO	CO_2 Regulated Case 2 RTO	High Fuel Prices Case 3 RTO	High Fuel Prices + CO_2 Regulated Case 4 RTO
2025	30.2	29.2	28.9	28.3	31.6	21.3	14.9	8.2
2026	31.1	29.7	29.1	28.6	33.1	24.3	14.5	7.6
2027	31.4	30.1	29.5	29.0	32.8	26.0	13.9	7.8
2028	26.5	25.2	23.7	23.8	28.4	24.5	15.4	8.5
2029	22.0	20.5	19.1	18.6	27.8	24.5	15.4	8.7
2030	22.4	20.7	19.3	18.8	27.6	25.5	16.5	9.2
2031	22.5	20.8	19.3	18.7	27.9	25.8	17.4	9.7
2032	23.0	21.0	19.5	18.9	28.3	26.0	17.6	9.6
2033	22.0	19.9	18.6	17.9	27.3	24.1	16.1	8.9
2034	17.7	15.5	14.1	13.5	17.6	16.2	12.3	7.9
2035	13.5	11.2	10.1	9.4	16.6	15.1	12.0	8.1
2036	7.8	6.7	6.1	5.7	12.9	11.6	9.8	7.1
2037	5.9	5.3	4.9	4.7	8.6	7.9	7.1	5.6
2038	5.0	4.8	4.4	4.4	8.2	7.3	6.7	5.4
2039	4.4	4.2	4.1	4.0	4.9	4.5	4.5	4.1
2040	4.0	3.8	3.9	3.8	4.7	4.4	4.4	4.2

Table E2. Percent Reduction from 2010 Baseline (39.5 million short tons)

Year	Baseline Case 1 SA	CO_2 Regulated Case 2 SA	High Fuel Prices Case 3 SA	High Fuel Prices + CO_2 Regulated Case 4 SA	Baseline Case 1 RTO	CO_2 Regulated Case 2 RTO	High Fuel Prices Case 3 RTO	High Fuel Prices + CO_2 Regulated Case 4 RTO
2025	23%	26%	27%	28%	20%	46%	62%	79%
2026	21%	25%	26%	27%	16%	39%	63%	81%
2027	21%	24%	25%	27%	17%	34%	65%	80%
2028	33%	36%	40%	40%	28%	38%	61%	78%
2029	44%	48%	52%	53%	30%	38%	61%	78%
2030	43%	48%	51%	53%	30%	35%	58%	77%
2031	43%	47%	51%	53%	29%	35%	56%	76%
2032	42%	47%	51%	52%	28%	34%	56%	76%
2033	44%	50%	53%	55%	31%	39%	59%	77%
2034	55%	61%	64%	66%	56%	59%	69%	80%
2035	66%	72%	75%	76%	58%	62%	70%	80%
2036	80%	83%	85%	86%	67%	71%	75%	82%
2037	85%	87%	88%	88%	78%	80%	82%	86%
2038	87%	88%	89%	89%	79%	82%	83%	86%
2039	89%	89%	90%	90%	88%	89%	89%	90%
2040	90%	90%	90%	91%	88%	89%	89%	89%

Table E3. Emissions Costs

Year	Baseline Case 1 SA	CO_2 Regulated Case 2 SA	High Fuel Prices Case 3 SA	High Fuel Prices + CO_2 Regulated Case 4 SA	Baseline Case 1 RTO	CO_2 Regulated Case 2 RTO	High Fuel Prices Case 3 RTO	High Fuel Prices + CO_2 Regulated Case 4 RTO
2025	$0	$430,666,094	$0	$417,777,547	$0	$313,879,705	$0	$120,365,861
2026	$0	$457,519,925	$0	$441,026,467	$0	$373,740,046	$0	$117,409,854
2027	$0	$484,557,079	$0	$465,979,386	$0	$418,159,379	$0	$124,669,121
2028	$0	$422,853,414	$0	$399,429,835	$0	$411,454,242	$0	$143,137,410
2029	$0	$358,754,683	$0	$326,387,280	$0	$430,383,444	$0	$151,734,164
2030	$0	$379,660,516	$0	$343,960,905	$0	$467,341,480	$0	$168,652,410
2031	$0	$397,855,620	$0	$358,765,730	$0	$494,648,792	$0	$185,168,086
2032	$0	$420,835,386	$0	$378,509,316	$0	$520,333,061	$0	$192,684,192
2033	$0	$416,334,149	$0	$374,888,942	$0	$504,532,465	$0	$187,046,256
2034	$0	$340,097,364	$0	$295,016,462	$0	$355,348,338	$0	$173,137,521
2035	$0	$256,670,338	$0	$215,079,296	$0	$345,084,129	$0	$184,369,508
2036	$0	$159,253,906	$0	$136,808,428	$0	$278,374,058	$0	$170,623,244
2037	$0	$132,102,873	$0	$118,705,043	$0	$197,240,692	$0	$141,444,154
2038	$0	$124,688,391	$0	$115,223,280	$0	$190,290,037	$0	$141,576,359
2039	$0	$116,042,179	$0	$108,360,589	$0	$122,224,116	$0	$113,328,817
2040	$0	$109,911,111	$0	$107,348,046	$0	$125,113,175	$0	$119,040,963

EXHIBIT ACL-7

East Kentucky Power Company's

2022 Integrated Resource Plan

2022 INTEGRATED RESOURCE PLAN

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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East Kentucky Power Cooperative, Inc.

Case No. 2022-00098
Integrated Resource Plan by Electric Utilities Filing Requirements
Table of Contents

Page Reference	Filing Requirement	Description
Noted	807 KAR 5:058 Section 1(1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.
Noted	807 KAR 5:058 Section 1(2)	**Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.**
Noted	807 KAR 5:058 Section 1(3)	**Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission.**
N/A	807 KAR 5:058 Section 3	**Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.**
15	807 KAR 5:058 Section 4(1)	**Format: The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.**
15	807 KAR 5:058 Section 4(2)	Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.
807 KAR 5:058 Section 5		Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum:
1-3	807 KAR 5:058 Section 5(1)	Description of the utility, its customers, service territory, current facilities, and planning objectives;

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SECTION 1.0

EXECUTIVE SUMMARY

SECTION 1.0

EXECUTIVE SUMMARY

1.1 General Overview

807 KAR 5:058 Section 5(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative Inc. ("EKPC") is a not-for-profit, member-owned generation and transmission cooperative located in Winchester, Kentucky. EKPC provides electricity to 16 owner-member distribution cooperatives (owner-members) with more than 550,000 meters at homes, farms and businesses in 87 Kentucky counties. EKPC does not directly serve any retail customers. Owner-members served by EKPC include:

Big Sandy RECC	Jackson Energy Cooperative
Blue Grass Energy Cooperative	Licking Valley RECC
Clark Energy Cooperative	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative
Farmers RECC	Salt River Electric Cooperative
Fleming-Mason Energy Cooperative	Shelby Energy Cooperative
Grayson RECC	South Kentucky RECC
Inter-County Energy Cooperative	Taylor County RECC

EKPC owns and operates coal-fired generation at the John Sherman Cooper Station in Pulaski County (341 MW) and the Hugh L. Spurlock Station in Mason County (1,346 MW). EKPC owns and operates gas-fired generation at the J.K. Smith Station in Clark County (989 MW winter rating) and Bluegrass Generation Station in Oldham County (567 MW winter rating). EKPC also owns and operates Landfill Gas to Energy renewable generation facilities in Boone County (4.6 MW), Laurel County (3.0 MW), Barren County (0.9 MW), Greenup County (2.3 MW), Hardin County (2.3 MW) and Pendleton County (3.0 MW). EKPC owns an 8.5 MW solar generation facility in Clark County.

EKPC purchases 170 MW of hydropower from the Southeastern Power Administration ("SEPA") on a long-term basis, generated from the Cumberland River hydropower system. Laurel Dam (70 MW) historically has been a reliable resource.

In total, EKPC owns and/or purchases 3,438 MW (winter rating) or 3,136 MW (summer rating) of generation. EKPC operates within the PJM Interconnection, Inc. ("PJM"), which has more than 180,000 MW of generation capacity.

EKPC owns and operates a 2,968-circuit mile network of high voltage transmission lines consisting of 69 kV, 138 kV, 161 kV, and 345 kV lines, and all the related substations. EKPC is a member of the SERC Reliability Corporation ("SERC"). EKPC maintains 77 normally closed free-flowing interconnections with its neighboring utilities.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

One of EKPC's strategic objectives is to actively manage its current and future asset portfolio to safely deliver reliable, affordable and sustainable energy from appropriately diversified resources, and work with federal and state stakeholders to ensure high reliability and economic viability while mitigating evolving regulatory challenges including possible carbon emissions reduction mandates and penalties. EKPC will accomplish this objective by actively managing its current and future asset portfolio to maintain high reliability of electric service to its owner-members and economically diversify its energy resources, including market purchases, fossil fuels, renewables, storage, demand management and energy efficiency programs, and partnering opportunities.

Another strategic objective is to continue to ensure reliability and affordability of electric service while supporting beneficial electrification and thoughtfully responding to growing pressures to decarbonize. EKPC will continue to manage for reliability and minimize negative financial impacts to end consumers while supporting beneficial electrification that could generate exponential load growth, particularly through continuing penetration of electric vehicles, electrification of industrial processes, and electrification of residential and commercial heating applications. EKPC will also work with state, federal, regional, and PJM stakeholders to respond to the legal, regulatory, and industry pressures to decarbonize the fleet through solutions based on science and engineering that ensure electric service continues to be highly reliable and available at an acceptable cost to the public.

1.2 Load Forecast

EKPC's load forecast is prepared every two years in accordance with EKPC’s Rural Utilities Service (RUS) approved Work Plan. The Work Plan details the methodology used in preparing the projections. EKPC prepares the load forecast by working jointly with each owner-member to prepare its load forecast. The summation of these is the EKPC system forecast. Owner-members use their load forecasts in developing distribution system construction work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast in demand side management analyses, marketing analyses, transmission planning, power supply planning, sustainability planning and financial forecasting.

The forecast indicates that for the period 2022 through 2036, total energy requirements will increase on average 1.1 percent per year. Winter and summer net peak annual demand will increase by 0.6 percent and 0.8 percent, respectively, on average.

EKPC notes that PJM prepares a load forecast for the full PJM geographic region, including the utility zones in Kentucky that are part of the PJM region. That forecast is used in PJM’s long-term transmission expansion planning process and in the PJM Reliability Pricing Model, which are both discussed in later in this IRP. The forecast of is used to drive transmission projects EKPC must construct and EKPC’s capacity obligation in PJM’s Reliability Pricing Model (RPM) capacity market. EKPC contributes to the analysis by highlighting any anticipated load changes that might impact PJM’s forecast.

1.3 Demand Side Management (DSM)

EKPC selects Demand-Side Management ("DSM") programs to offer on the basis of meeting customer preferences and resource planning objectives in a cost-effective manner. EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost- effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the California tests.

For this 2022 IRP, EKPC has contracted with GDS Associates, Inc. (“GDS”) to conduct an updated and enhanced study of energy efficiency (EE) and demand response (DR) savings potential. For this study, a cost-effectiveness screening of a comprehensive set of measures using the Total Resource Cost test from the California standard was performed.

EKPC prepared cost and participation estimates for all of the DSM programs in this plan, and conducted a final cost-effectiveness analysis for each DSM program using the widely accepted "*DSMore*" software tool.

EKPC has used the scenario described as $3 million energy efficiency (“EE”) budget from the GDS potential study to develop energy efficiency participation estimates for the DSM programs.

1.4 PJM Membership

EKPC integrated its operations into the PJM market on June 1, 2013. PJM membership continues to drive significant beneficial operation changes and significant cost savings for EKPC’s owner-members. PJM operates a reliability constrained, two-settlement Energy Market, that day-ahead matches load requirements with economic generation and demand resources and balances the actual needs in real-time. EKPC’s generation fleet is economically dispatched with PJM’s other generation and demand resources (over 180,000 MW) which has significantly affected EKPC’s electric power procurement and energy accounting practices. As expected, EKPC’s total power supply costs to its owner-members have decreased subsequent to integration due to the economies of scale of a much larger system dispatch (i.e., diversity of supply resources and diversity of load needs across the PJM region). EKPC identified substantial net savings realized through May 31, 2021, as documented in its annual reports to the Executive Director of the Kentucky Public Service Commission (“Commission”).

In addition to the daily energy market participation, EKPC participates in the ancillary services markets providing regulation service and synchronized reserves.

EKPC also participates in PJM’s capacity market, called Reliability Pricing Model, and Financial Transmission Rights auctions

EKPC’s obligation to PJM for capacity is defined by the RPM. PJM establishes a Variable Resource Requirement against which all supply resources clear, establishing the clearing price for committed capacity resources. The Variable Resource Requirement incorporates the reserve requirement established for the particular delivery year. Among other factors, the reserve requirement incorporates PJM’s summer peak load forecast, forced outage rates of resources and, an expectation of resources the PJM region might receive from other regions during emergency conditions. The calculated reserve requirement for the delivery year June 1, 2022 through May 31, 2023 is 14.9% installed reserve margin, established in 2021. All EKPC capacity resources that clear in the market are committed to the PJM region to ensure resource adequacy; all committed resources are responsible to perform when PJM needs them to ensure regional reliability. All also must offer into the Day Ahead Energy Market.

The commitment of capacity resources to be available to produce electricity in a future delivery year, however, does not lock in energy market prices for that future delivery year. The only way to guarantee a maximum cost on energy is to secure enough resources or energy contracts to hedge the prices that may result from the real time conditions and fuel prices in the energy market. EKPC takes measures to hedge its energy price exposure through the entire year.

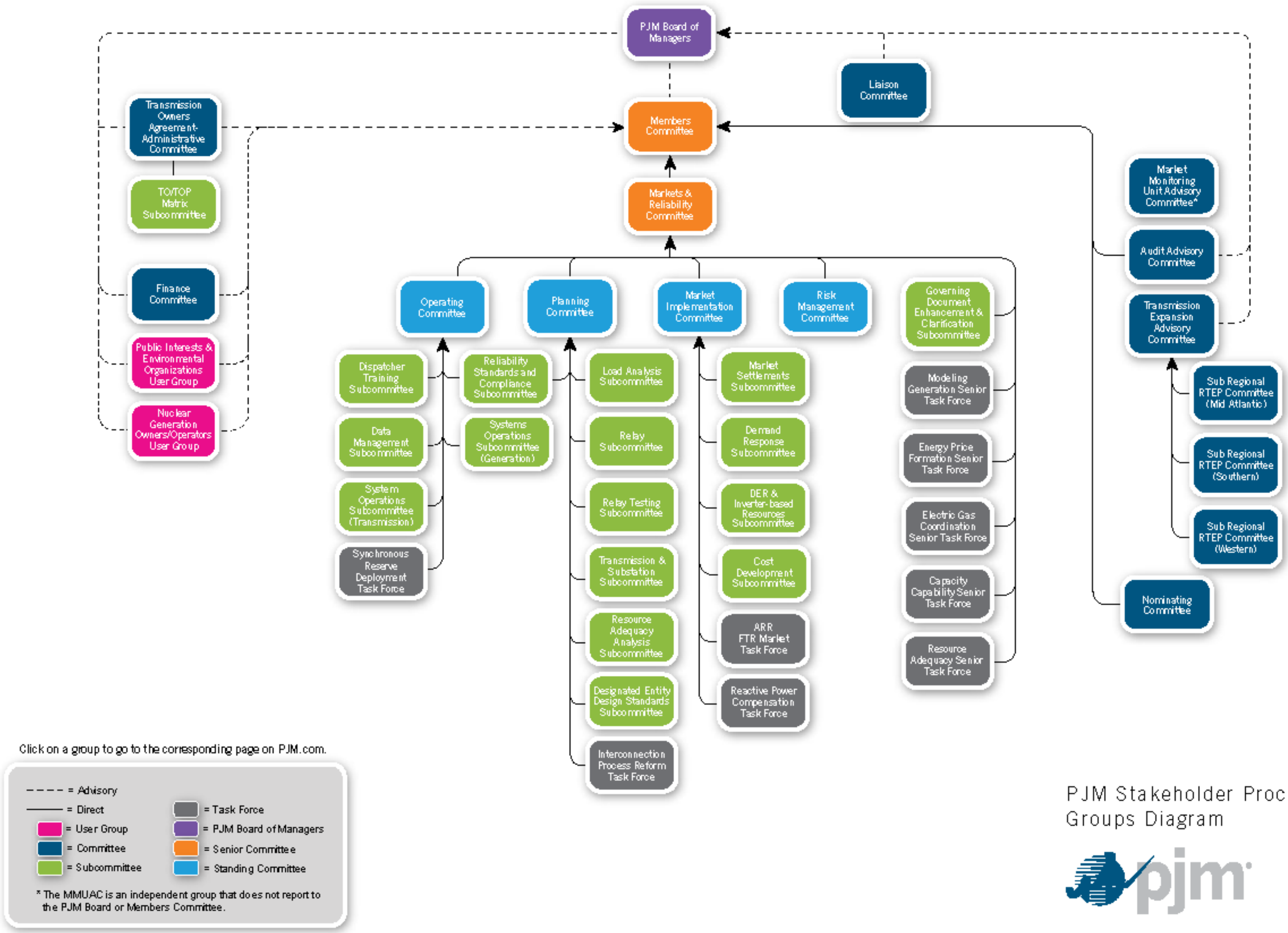
As a member of PJM, EKPC is actively involved in the PJM Stakeholder Process. The Stakeholder Process is comprised of two Senior Committees (Members Committee and the Markets and

Reliability Committee), four additional Standing Committees (Market Implementation, Operating, Planning, and Risk Management Committees), Subcommittees or Working Groups created by these six Committees, and User Groups established in accordance with PJM's Operating Agreement.

Proposals to revise PJM governing documents and business practice manuals are considered in a hierarchical committee process. Proposed changes move from the subcommittees and working groups to their "parent" Standing Committee and from there to the "parent" Senior Committee. Proposals approved by this Stakeholder Process then move from the Senior Committee to the PJM Board of Directors for consideration or approval. Any changes to PJM governing documents must be submitted to the Federal Energy Regulatory Commission ("FERC") for approval.

EKPC is represented on each of the Senior and Standing Committees. EKPC is also represented on key Subcommittees and Working Groups that address matters of importance to EKPC. The EKPC representatives to the PJM Committees, Subcommittees, and Working Groups share what they have heard regarding the issues and policy development within the PJM Stakeholder Process and report to EKPC's Senior Executives. Additionally EKPC representatives advocate for interests through the subcommittees. Please see the PJM committee organizational chart on the following page or visit the following link
https://www.pjm.com/-/media/committees-groups/committee-structure-diagram.ashx

PJM Stakeholder Process Groups Diagram



1.5 EKPC Sustainability Plan

In 2018, EKPC's Board of Directors approved an update to the Mission Statement that now reads: EKPC exists to serve its member-owned cooperatives by safely delivering reliable, affordable and sustainable energy and related services. Then EKPC staff embarked on creating a sustainability plan to support the mission statement. Five (5) staff member teams were created to develop a better understanding of the changes taking place in and around the energy industry, changes that will affect EKPC for decades to come. The teams developed a sustainability plan that was approved by the EKPC Board of Directors in 2020. The sustainability plan and individual team initiatives are found at https://www.ekpc.coop/ekpc-planning-future.

1.6 Power Supply Actions

EKPC desires to keep its plans as flexible as possible to be able to adjust to market and load conditions as needed. EKPC continues to monitor its load and all economic power supply alternatives. EKPC joined PJM on June 1, 2013, which has significantly beneficially impacted its operations and improved its ability to economically serve its native load. EKPC realized significant savings benefits from operating within PJM from June 1, 2013 through May 31, 2021, as described in its annual reports to the Commission. EKPC's existing resource portfolio adequately meets its power supply requirements for the next several years. EKPC continuously evaluates its resource portfolio compared to its forecasted load profile and considers how best to hedge its energy market price exposure and future load needs. EKPC has sufficient capacity resources to meet its forecasted summer load peaks through the IRP study period. It expects to utilize Power Purchase Agreements ("PPAs") to cover the future winter period needs for a hedge against energy price exposure and solar PPAs to meet its sustainability goals on an economic basis.

1.7 Recommended Plan of Action

807 KAR 5:058 Section 5(5) Steps to be taken during the next three (3) years to implement the plan.

EKPC exists to serve its owner-member Cooperatives by safely delivering reliable, affordable and sustainable energy and related services. EKPC's objective of the power supply plan is to develop an economic, reliable and sustainable plan, while simultaneously mitigating financial and operational risks. EKPC has an on-going planning process and this IRP represents only one snapshot in time of the process. Changing conditions will warrant changes to EKPC's long term plans.

To meet its objective, EKPC will take the following actions in the near term:

- Continue to monitor economic and load growth conditions including distributed generation;
- Continue to develop and promote cost-effective DSM programs;
- Monitor sustainable energy resources and obtain resources through Power Purchase Agreements as needed to meet strategic and load driven directives;
- Continue to evaluate energy price hedges for winter seasons and review against market and owned-generation options;
- Continue to maximize the operational and economic benefits realized by being a member of PJM;
- Work with federal and state stakeholders to ensure the economic viability of EKPC's existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations.
- Advocate for rules and policies that resolve the current PJM interconnection queue backlog.

1.8 Issues or Uncertainties that Could Affect Successful Implementation of Plan

807 KAR 5:058 Section 5(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

As with any plan, there are risks and uncertainties associated with the recommended plan of action. Below are the risks and uncertainties identified by EKPC.

- *Continue to monitor economic and load growth conditions including distributed generation.* If EKPC were to miss significant changes in its load conditions that would warrant investing in capital-intensive power supply projects, then the long-term impact to owner-members may be higher financing costs for future projects. Therefore, monitoring economic and load conditions, as well as distributed generation being installed behind the meter throughout the system, is critical to EKPC's plans, as is remaining aware of project opportunities.

- *Continue to develop and promote cost-effective DSM programs*. EKPC desires to develop reasonable and economic DSM programs. Participation in these programs by retail customers will ultimately determine the amount of energy savings and capacity that is avoided. EKPC uses California tests to cost justify its DSM tariffs. The California tests compare DSM programs to the avoided costs of capacity and energy. EKPC is pursuing DSM programs that pass the Total Resource Cost ("TRC") tests. EKPC has re-evaluated all of its DSM programs for cost-effectiveness. Some programs have been eliminated and others have been modified. EKPC will continue to assess the cost-effectiveness of DSM programs as avoided costs change, and will adjust its portfolio as needed. Power supply plans will need to be adjusted according to the actual amount of DSM realized. EKPC has kept its power supply plans flexible, which will help facilitate DSM implementation, in that EKPC plans to make purchases to cover peaking power supply requirements. These purchases allow for the maximum amount of DSM to be developed while not placing the EKPC power supply system at risk.

- *Monitor sustainable energy resources and obtain resources through Power Purchase Agreements as needed to meet strategic and load driven directives.* EKPC has developed a sustainability plan that indicates EKPC will need to obtain additional green energy resources to meet its goals. EKPC's owner-members are receiving more requests from their large consumers to provide green energy options for their power supply. EKPC will seek to secure the requested power supply alternatives. EKPC's Wholesale Renewable Energy tariff, frequently called the Green Energy Tariff, has been developed in direct response to these requests. Because EKPC is not a taxable entity, it has been more economic for EKPC to purchase power from an entity that can take full advantage of the federal tax savings than to develop its own solar projects. EKPC plans to advocate for policies that would allow non-taxable entities such as cooperatives and municipals to receive similar financial incentives as renewable developers that are taxable.

- *Continue to evaluate energy price hedges for winter seasons and review against market and owned-generation options.* The PJM capacity obligation EKPC must satisfy is based on the summer peak load forecast. EKPC has sufficient capacity resources in its portfolio to satisfy summer peak load requirements. Providing adequate capacity does not ensure energy prices. EKPC must continually review its available resources compared to its energy needs on an on-going basis to provide an adequate price hedge for its energy needs throughout the year. EKPC's owned generation resources and long term contracts provide adequate energy price hedges for all but the coldest winter months. EKPC continually reviews its options for supplying adequate energy price hedges for the winter season and thus far, has determined that securing firm energy purchases from third parties for specific months is its most economic option. EKPC's experiences in January of 2014 and February of 2015 highlighted the need to secure price hedges for its winter energy. Based on the results of the studies described in Section 8 of this IRP, EKPC intends to purchase PPAs to cover its future winter energy price hedges. EKPC will seek to find the most economic alternative to meet its power supply requirements while also ensuring satisfaction of state and federal environmental requirements.

- *Continue to maximize the operational and economic benefits realized by being a member of PJM.* EKPC joined PJM on June 1, 2013. EKPC identified significant cost savings that accrued to its members from June 1, 2013 through May 31, 2021 in its annual reports to the

Commission. EKPC anticipates it will continue to realize similar savings going forward. EKPC actively participates in the PJM Committees and stakeholder processes. EKPC provides continuing education to its System Operators to keep them certified to operate within the PJM system, and provides training to other key personnel to ensure that opportunities for improvement are being recognized and utilized.

- *Work with Federal and State stakeholders to ensure the economic viability of EKPCs existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations.* EKPC is committed to deliver reliable, affordable and sustainable energy from appropriately diversified fuel sources to its owner-members. EKPC supports the deployment of renewable and other no/low carbon emitting generation resources onto the transmission grid. However, EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

- *Advocate for rules and policies that resolve the current PJM interconnection queue backlog.* All generation resources seeking to connect to the PJM transmission system, including EKPC's transmission system, must be studied by PJM to ensure any necessary upgrades to the system are made to reliably support the injection of power and delivery to load across the PJM system. PJM has become significantly delayed in finalizing the study results of hundreds of projects in the study queue. Unless the generation project is in the last steps of the study process, it is unlikely that the project will be able to move forward to construction in the next few years. Neither EKPC nor any other generation developer will be able to construct a project not currently in the queue for several years as PJM works through the backlog of project studies PJM and stakeholders have developed a proposed solution to address this issue and expect to file the proposal with the Federal Energy Regulatory Commission in May 2022. At this time EKPC does not expect a reliability issue to materialize from the backlog, but because of the significant delay that any new project will experience, a concern could arise if a generator needed to deactivate or repower and its replacement is delayed. Delays also may challenge the achievement of decarbonization or other sustainability goals. Green Power Tariff requests as well as projects desired to meet sustainability goals, may face delays in project development. EKPC will stay actively involved in PJM policy and rules development in an effort to advance its ability to meet future energy and capacity needs. More details are included in section 6.0 of this IRP.

1.9 EKPC Demand Side Management and Renewable Energy Collaborative (Collaborative 2.0)

EKPC re-engaged the public interest groups and other interested parties in 2021 and established the EKPC Sustainability Collaborative. A new charter for the Collaborative was created with its primary purpose of promoting participation in demand side management, energy efficiency, renewable energy, and beneficial electrification programs offered by EKPC and EKPC's owner-member cooperatives. The following table identifies the organizations participating in the Collaborative.

Company/Organization	
East Kentucky Power Cooperative	Bluegrass GreenSource
Big Sandy RECC	Kentucky Conservation Committee
Blue Grass Energy Cooperative	Kentuckians for the Commonwealth
Clark Energy Cooperative	Kentucky Interfaith Power and Light
Cumberland Valley Electric	Frontier Housing
Farmers RECC	Kentucky Industrial Utility Customers
Fleming-Mason Energy Cooperative	Mountain Association
Grayson RECC	Nucor/Gallatin Steel
Inter-County Energy Cooperative	Kentucky Association of Manufacturers
Jackson Energy Cooperative	Kentucky Chamber of Commerce
Licking Valley RECC	**Non-voting Members and Observers (Invited)**
Nolin RECC	**Company/Organization**
Owen Electric Cooperative	Center for Applied Energy Research
Salt River Electric Cooperative	Energy and Environment Cabinet
Shelby Energy Cooperative	
South Kentucky RECC	
Taylor County RECC	

The Collaborative met four (4) times in 2021. Meeting minutes are included in Exhibit 8 of the Technical Appendix, Volume 2, Demand Side Management.

1.10 Organization of the 2022 IRP

807 KAR 5:058 Section 4(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.

Individuals responsible for the preparation of the IRP include:

David Crews, Senior Vice President of Power Supply
Craig Johnson, Senior Vice President of Power Production
Julia Tucker, Director of Power Supply Planning
Jerry Purvis, Vice President of Environmental Affairs
Denise Foster Cronin, Vice President of Federal and RTO Regulatory Affairs
Fernie Williams, Manager of Power Supply Analytics
Darrin Adams, Director of Transmission Planning and Protection
Jena McNeil, Director of Legislative and Government Relations
Scott Drake, Manager of Corporate Technical Services
Robin Hayes, Director of Financial Planning and Analysis
Jacob Watson, Sr. Load Forecast Analyst
Mark Mefford, Sr. Load Forecast Analyst
Chris Adams, Director of Regulatory and Compliance
Legal Counsel: David Samford, Goss Samford PLLC
L. Allyson Honaker, Goss Samford PLLC

807 KAR 5:058 Section 4(1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.

EKPC's 2022 IRP is organized in accordance with the sequencing of the planning process, while clearly cross-referencing the appropriate citation to 807 KAR 5:058.

EKPC used the PSC Staff Report of the 2019 IRP as a starting point in the analysis underlying this IRP. The PSC Staff Report recommendations, along with the basic requirements of the Commission's regulations, are the foundation for this Integrated Resource Plan.

1.11 Significant Changes from 2019

807 KAR 5:058 Section 6. Significant Changes. All integrated resource plans shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate change

EKPC Changes Mission Statement and Develops a Sustainability Plan

In 2018, EKPC's Board of Directors approved an update to the Mission Statement that now reads: EKPC exists to serve its member-owned cooperatives by safely delivering reliable, affordable and sustainable energy and related services. Then EKPC staff embarked on creating a sustainability plan to support the mission statement. Five (5) staff based teams were created to develop a better understanding of the changes taking place in and around the energy industry, changes that will affect EKPC for decades to come. The five (5) teams are:

- Owner-Members
- Employees
- Energy and Environment
- Electric Grid
- Financial Health

Generally, sustainability plans center around the Environmental, Social, and Governance ("ESG") responsibility of a corporation. Each of the five (5) teams developed the team's purpose, guiding principles, and initiatives for long-term success. Collectively, the team's individual plans formed the EKPC Sustainability Plan. In 2020, EKPC's Board of Directors approved the EKPC Sustainability Plan.

EKPC, led by each team, is actively engaged and working to achieve the initiatives of the sustainability plan. Most notable are EKPC's effort to reduce carbon dioxide emissions and pursue renewable resources while also ensuring reliability and cost effectiveness for its owner-members.

The sustainability plan and individual team initiatives are found at https://www.ekpc.coop/ekpc-planning-future.

Cooperative Solar One

EKPC, along with its sixteen owner-members, implemented a community solar project in order to offer renewable solar energy to end users within the owner-members' service territories. This project is a result of the Demand Side and Renewable Energy Collaborative group's efforts. The 8.5MW facility began operations in November 2017. Marketing of the 25-year licenses continues under the Cooperative Solar program, which offers benefits of solar generation without the installation and maintenance requirements that would be necessary in a smaller home or office installation. This facility produced 13,204 MWh in 2021.

DSM Program Changes

EKPC updated its Energy Efficiency and Demand Response Potential Study (performed by GDS) for this plan. The project scope included a detailed energy EE and DR potential study for residential and commercial/industrial customers.

The findings this time were very similar to the earlier 2018 study. There were only minor differences in the list of measures that proved to be cost-effective. EE potential as a percentage of forecasted sales remained steady (26.0% versus 26.6 % for economic potential).

EKPC is proposing no significant changes to its portfolio of DSM programs. No new programs are proposed in this IRP.

DSM Carbon Cases

For this IRP, EKPC hired Guidehouse consultants to assess the impact of potential future decarbonization policies and their impact on energy market prices. EKPC used the market energy prices from the different decarbonization scenarios to evaluate the cost-effectiveness of EE programs.

EKPC had GDS evaluate cost-effectiveness under four (4) economic scenarios using the Guidehouse decarbonization energy price forecasts:

- Base Case – EKPC's avoided costs for energy and capacity from PJM
- Low Carbon – Base case plus $3.49 per MWh adder for carbon costs based on the Regional Greenhouse Gas Initiative ("RGGI")
- Mid Carbon – Base case plus $23.41 per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus $65.24 per MWh adder for carbon costs based on the social cost of carbon in New York. Information regarding the social cost of carbon in New York can be found at https://www.dec.ny.gov/press/122070.html.

While EKPC does not anticipate in the near term being required by a federal or state law to pay the Mid or High Carbon cost adder, the added carbon costs versus DSM program impacts sensitivity analyses were evaluated. As the price of energy increases, resulting from decarbonization, more EE programs become cost effective.

EKPC directed GDS to estimate energy and demand impacts for four annual EE scenarios corresponding to four economic scenarios. The economics scenario levels were chosen to represent reasonable expected spend for each scenario.
EKPC prepared DSM plans for each of four scenarios.

The increased energy cost associated with the Mid and High carbon cases show two (2) additional EE programs (the ENERGY STAR® Appliance rebate program, and the Small Business Lighting program) are cost-effective. EKPC does not anticipate a requirement for a carbon adder to apply to generation resources, therefore EKPC is not adopting the mid and high carbon cases.

These are the projected cumulative energy and demand savings in 2036 for each of these four scenarios:

Scenario	Annual MWh	Winter Peak MW	Summer Peak MW
Base	110,151	30	49
LOW carbon	171,896	49	56
MID carbon	251,474	64	70
HIGH carbon	407,873	127	97

DSM Differences

Table 1-1 presents the differences between the 2019 DSM plan and the 2022 DSM plan. The 2019 plan impacts are adjusted for a 2021 base year to match the base year of the current plan.

Section 5.0 - Demand Side Management - provides more details of the DSM plan.

Table 1-1
Comparing DSM Impact projections from the 2019 IRP with the 2022 IRP

	2019 IRP			2022 IRP		
Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	9,942	2	2	7,508	2	3
2023	19,664	4	4	15,016	4	7
2024	28,976	5	6	22,523	6	10
2025	38,405	7	8	30,031	8	13
2026	47,835	8	10	37,539	10	16
2027	56,045	10	12	44,800	12	20
2028	64,189	11	14	52,061	14	23
2029	72,334	13	15	59,323	16	26
2030	80,478	15	17	66,584	18	29
2031	88,623	16	19	73,845	20	33
2032	96,768	18	20	81,106	22	36
2033	104,912	19	22	88,368	24	39

<u>Discussion of differences between 2022 IRP Load Forecast and the 2019 IRP Load Forecast</u>

The most significant differences are the base year energy and customers, the expansion of an industrial customer and DSM impacts. In 2022, total energy requirements by 2032 are a little over 500,000 MWh lower than the previous IRP, 15-year growth rates are slightly lower (1.1 vs 1.4 percent). Similarly, residential customers in 2022 are just over 400 less than the previous IRP and the growth rate is slightly lower (0.7 vs 0.8 percent).

Growth in use-per-customer is dampened by energy efficiency improvements for appliances, as well as thermal integrity of structures. In general, homes have more connected load but it is not enough to offset efficiency impacts. This has been true for the last few years and is projected to continue. The owner-members in the eastern part of the state continue to struggle due to the economy and decline in mining. Others are seeing new commercial and industrial growth, as well as subdivision development. Table 1-2 displays comparisons between the 2019 IRP and 2022 IRP load forecasts.

Table 1-2 Forecast Comparison 2022 IRP Versus 2019 IRP				
		2022 IRP	2019 IRP	Difference
Residential Sales, MWh	2022	7,241,094	7,207,766	33,328
	2027	7,391,408	7,532,016	(140,608)
	2032	7,665,895	7,863,946	(198,051)
Total Commercial and Industrial Sales, MWh	2022	6,337,822	6,910,612	(572,789)
	2027	7,333,281	7,385,968	(52,686)
	2032	7,641,367	7,743,812	(102,446)
Residential Customers	2022	521,049	521,474	(425)
	2027	540,328	541,620	(1,292)
	2032	559,802	561,901	(2,099)
Net Winter Peak, MW	2022	3,309	3,349	(40)
	2027	3,427	3,468	(41)
	2032	3,520	3,568	(47)
Net Summer Peak, MW	2022	2,500	2,448	52
	2027	2,651	2,545	106
	2032	2,726	2,664	62
Total Requirements, MWh	2022	14,421,062	15,241,723	(820,661)
	2027	15,604,583	16,012,368	(407,785)
	2032	16,227,680	16,752,464	(524,784)

Lastly, the DSM impacts for the first five years in the load forecast are lower than the previous IRP load forecast as a result of participation levels for DSM assumed for this IRP:

Table 1-3
DSM Impacts

2022 IRP	Energy (MWh)	Winter Peak (MW)	Summer Peak (MW)
Year 1	7,508	2	3
Year 2	15,016	4	7
Year 3	22,523	6	10
Year 4	30,031	8	13
Year 5	37,539	10	16
2019 IRP	**Energy (MWh)**	**Winter Peak (MW)**	**Summer Peak (MW)**
Year 1	10,689	2	2
Year 2	20,622	5	3
Year 3	30,576	7	5
Year 4	40,518	9	7
Year 5	50,240	11	9

Figure 1-1

Comparison of Load Forecasts
Net Total Energy Requirements (Millions MWh)

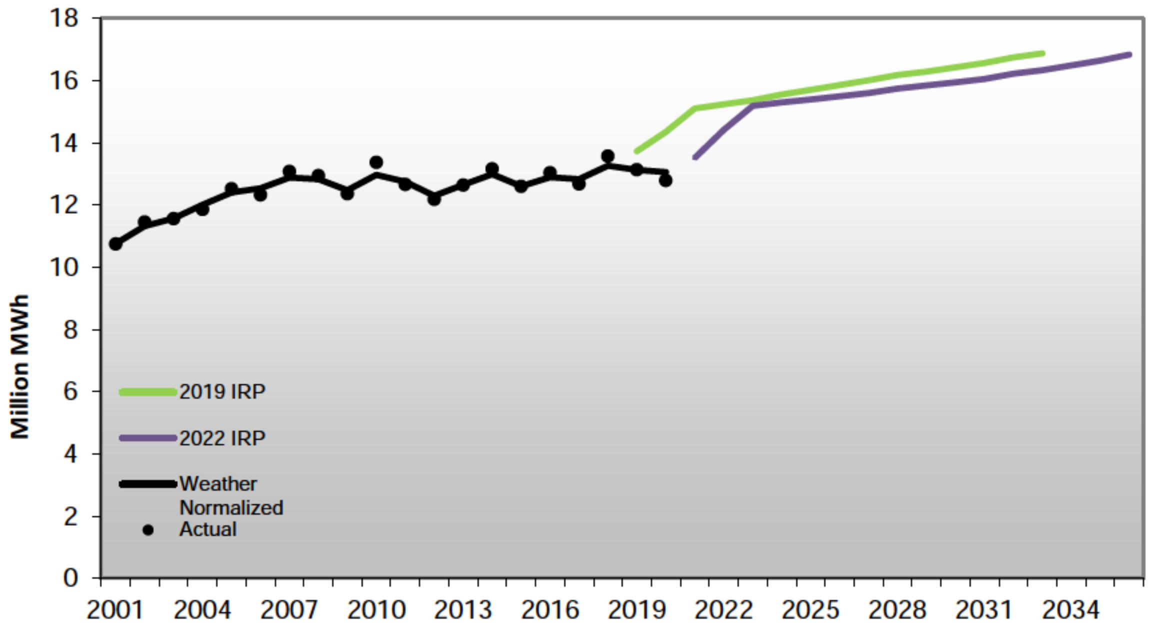


Figure 1-2

Comparisons of Load Forecasts
Winter Peak Demand Projections (MW)

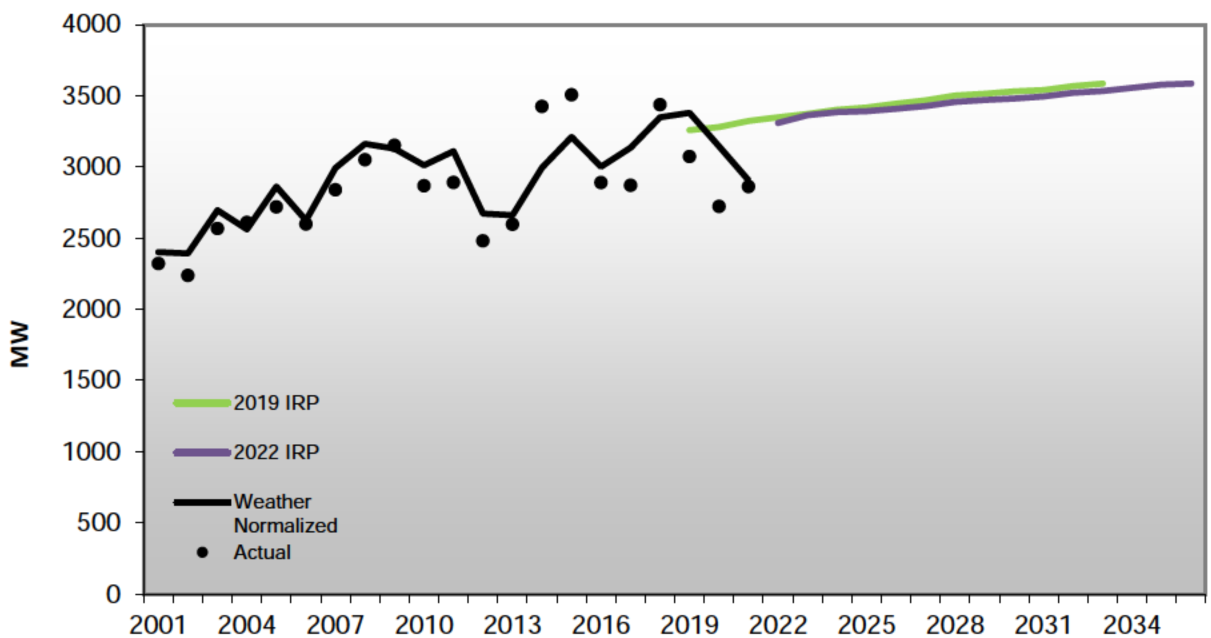
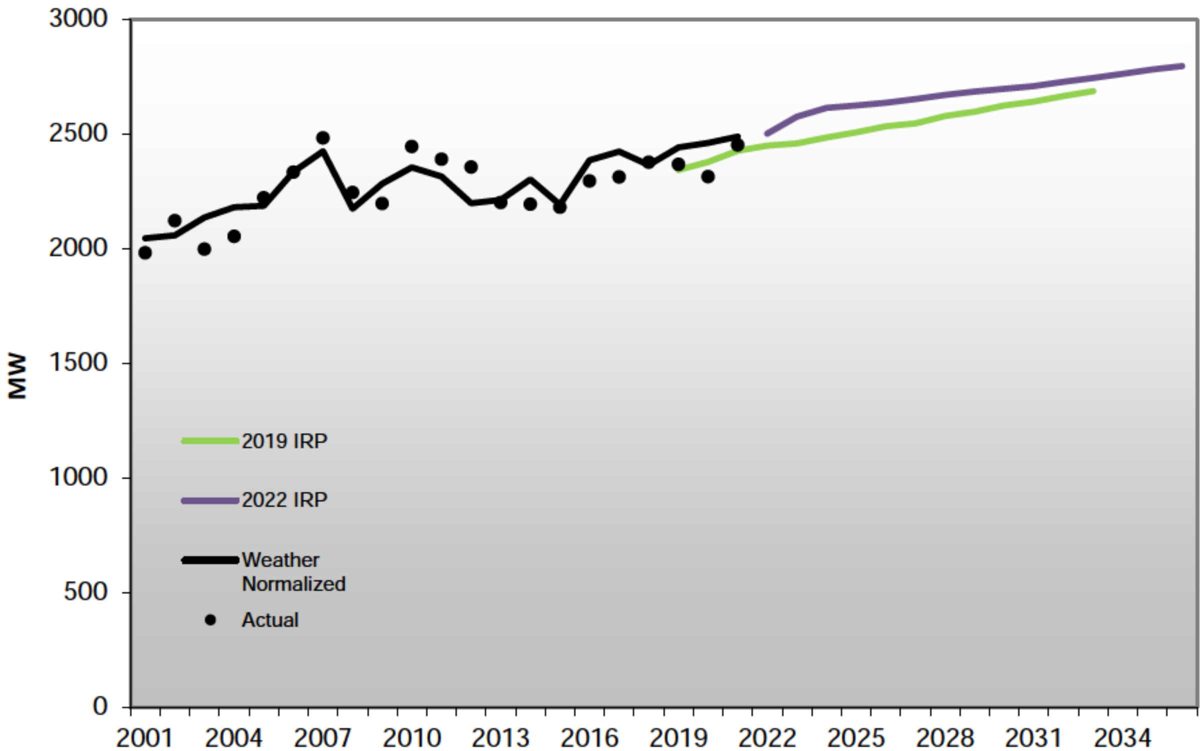


Figure 1-3

Comparison of Load Forecasts
Summer Peak Demand Projections (MW)



Difference between 2022 Expansion Plan and 2019 Expansion Plan

In comparison to the 2019 IRP, the projected capacity needs in the 2022 IRP are 73 MWs lower by the year 2032. EKPC joined PJM on June 1, 2013 and its future capacity requirements changed accordingly. PJM bases its members' capacity requirements on summer peak loads. However, EKPC continues to need to economically supply energy for its winter load requirements in addition to the PJM summer capacity requirements. The preparation process for the 2019 and 2022 IRPs considered similar renewable options in the resource planning process. Prices for solar, wind, and storage were used similarly for the creation of the least cost expansion plan to meet the required capacity requirements. The 2022 IRP preparation however added an additional external step to ensure EKPC's ability to meets its sustainability goal of 15% of new renewable energy in 2035, driven by the growing consumer and industry interest in green power in Kentucky. The load forecast for energy in 2035 provided a target and solar PPAs were added to meet the sustainability goal. The solar PPAs defined in Table 8-2 were used to layer in non-carbon energy to meet the intermediate sustainability step of 10% in 2030, and the final goal of 15% in 2035. EKPC's sustainability initiative results in additional renewable energy to meet our goal of 15% new renewable by 2035. This goal will be met in an economical manner.

Table 1-4
EKPC Projected Major Capacity Additions

	2019 IRP Capacity Available on January 1 — Winter Season Capacity				2022 IRP Capacity Available on January 1 — Winter Season Capacity		
Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions	Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)				(MW)		
2019				2019			
2020				2020			
2021				2021			
2022				2022			
2023				2023			
2024				2024			
2025				2025			
2026				2026			
2027				2027			
2028				2028			
2029				2029			
2030				2030			
2031				2031			
2032				2032		225 Simple Cycle CT	225
2033				2033			225
2034				2034			225
2035				2035			225
2036				2036			225
2037				2037			225

2019 IRP showed 2-100 MW Winter Call Options; these should have been denoted as energy hedges only, not capacity.

SECTION 2.0

COMMISSION REPORT ON THE 2019 IRP RECOMMENDATIONS

SECTION 2.0

COMMISSION STAFF RECOMMENDATIONS TO EKPC'S 2019 IRP

2.1 Introduction

EKPC submitted its 2019 IRP (Case No. 2019-00096) to the Commission on April 1, 2019. The report submitted by EKPC provided its plan to meet the power requirements of its 16 owner-members over the period 2019 to 2033. On November 23, 2020, EKPC received the Commission Staff's Report on EKPC's 2019 IRP. The purpose of the report was to review and evaluate EKPC's 2019 IRP in accordance with the requirements of 807 KAR 5:058, Section 11(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings.

2.2 PSC Staff Recommendations

807 KAR 5:058 Section 11(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing. (17 Ky.R. 1289; Am. 1720; eff. 12-18-90; 21 Ky.R. 2799; 22 Ky.R. 287; eff. 7-21-95.)

Below are the Commission Staff's recommendations from 2019 and EKPC's responses.

Load Forecasting

- **EKPC has appropriately sought to place forecast boundaries around its Base Case scenarios with its extreme Low Case and High Case scenarios, which, arguably, is the point of the sensitivity analysis. However, additional insights might be gained by varying fewer variables at an extreme level or combinations of low and high variables. For example, only weather varies from its base case assumptions or weather remains normal and economic conditions change. EKPC should conduct and report on additional sensitivity analyses to investigate alternate variations in input assumptions.**

  EKPC hired Guidehouse consultants to prepare several carbon price forecasts to use in its sensitivity cases.

- Base Case – Prices and forecasts used in this IRP as the base case
- Low Carbon – Base case plus a per MWh adder for carbon costs based on the RGGI
- Mid Carbon – Base case plus a per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus a per MWh adder for carbon costs based on the social cost of carbon in New York. Information regarding the social cost of carbon in New York can be found at https://www.dec.ny.gov/press/122070.html.

Under the Mid and High carbon cases, additional EE measures became cost-effective. The Mid case resulted in about 30% more measures being cost-effective. EKPC is not proposing change to programs based on these cases.

- **EKPC should include the addition and loss of a major industrial load in its sensitivity analyses, as well as the possible effects of an extreme event, such as a pandemic, whose immediate impact may last more than one year.**

EKPC's goal with sensitivity analysis is to determine reasonable upper and lower bounds for its peak and energy forecasts based on varying assumptions such as economic and weather inputs. The loss of an industrial customer falls within the lower bound of the scenarios prepared. The effects of an extreme event, such as a pandemic, also fall within the lower bound of the scenarios prepared. The effects of shifting loads from other fuel sources to electric for decarbonization is also a scenario that could occur and has been considered to be bounded by the high load forecast.

- **EKPC should discuss participation in regional economic development efforts, the extent to which it assists the owner-members in recruiting or retaining industrial customers, and the seemingly growing importance of being able to offer renewable energy to satisfy corporate sustainable energy goals as a facet of economic development efforts. In addition, the extent to which the existing industrial parks/development sites are certified and move-in ready should be discussed.**

EKPC is recognized by global site selectors, real estate professionals and corporate managers as the lead organization for Kentucky's Touchstone Energy Cooperatives. EKPC and its owner-members work hard to provide competitively priced, reliable, sustainable and accessible electric service to over one million Kentuckians and many of Kentucky's largest companies. EKPC supports leading statewide agencies and organizations with recruitment, expansion and retention of businesses that enhance the quality of life and employment across our commonwealth. EKPC partners routinely with global, national and state affiliations that include the Kentucky Cabinet for Economic Development, industrial authorities, economic development councils and government officials. EKPC staff supports and serves as board and committee members on many leading regional, state, national and global economic development organizations.

EKPC and its owner-members are eager to provide personnel assistance for recruitment, retention and expansion needs across our service territories. The sixteen (16) owner-member Cooperatives have each identified a staff member with a focus on economic development across their service territories. The EKPC team works closely with this staff to enhance education, networking and ultimately business recruitment, retention and expansion success.

From 2015 through 2021, EKPC assisted many partners and communities in securing 332 announced economic development projects that will invest over $8.6 billion and create over 17,000 jobs within our distribution cooperative service territories. 128 or 39% of these announced projects represented new facilities to Kentucky investing over $4.7 Billion and creating over 11,000 jobs.

EKPC also provides cutting edge technology and beneficial economic development tools. For over a decade, the sixteen (16) owner-member cooperatives have supported EKPC's development and implementation of various award winning economic development tools and programs. EKPC takes pride in providing the best and latest technology to better serve its clients and members. That is why EKPC created its targeted GPS-based mobile app called PowerMap https://dataispower.org/powermap. A first of its kind application that puts the power of locational knowledge in the hands of site selectors, economic developers and service providers. PowerMap provides users with detailed service territory maps for all 87 counties served by EKPC and owner-member Cooperatives. This award winning app uses a mobile device's GPS capabilities to determine if the user is in one of the 16 cooperatives' service territories. Users can pinpoint the exact location of interest, related industrial and business park information and determine which local electric cooperative provides direct service.

The owner-members and EKPC are also making site analysis and development easier than ever before. EKPC provides site selectors with an expanding list of Kentucky's top industrial properties, known as PowerVision Sites. This uses the latest drone technologies to provide an aerial showcase of available commercial and industrial tracts located across areas served by owner-member Cooperatives. With the PowerVision Site Advantage, site selectors have access to data, downloadable files and aerial videos. Users can conduct virtual site visits, create custom building renderings and more without leaving the comfort of home or office. During the time of global shut down and travel these tools have allowed the continued promotion of EKPC owner-member service territories and the commonwealth for global projects interested in Kentucky.

StateBook is another tool EKPC and its owner-members provide at no cost to the eighty seven (87) counties and territories served. StateBook provides trusted, sourced data to improve location analysis. 63,000 data points of information allows clients to better compare locations and identify the most strategic opportunities for investment, confirm project viability, and mitigate risk across disparate data sources, multiple geography levels and over time. Over 250 global site selection firms use StateBook in their decision making process.

EKPC's commitment to assisting new and expanding companies is further enhanced through financial programs designed to encourage new industrial growth. In addition to being knowledgeable on state and local incentives, the owner-members offer incentives to qualifying projects. Programs such as the Economic Development Rider reduces electric rates over a set period of time. Owner-Members also promote low-interest loans and grant options available through the USDA Rural Economic Development Loan and Grant Program ("REDLG").

The Cooperative commitment to an active role in developing a skilled workforce pipeline is unwavering. This dedication includes helping to shape the next generation of employees with STEM education. Through proactive involvement in numerous education and workforce initiatives, EKPC owner-members are working to deliver real-world workforce solutions that meet current and future demands. The communities are proving they have the vision, collaboration and workforce quality to surpass any employer's goals. Nearly 80 percent of the region has been state-certified as either a Work Ready or a Work Ready in Progress Community. EKPC routinely encourages and assists its service regions in obtaining this important certification that projects the communities are committed to providing the highly skilled workforce of today, and future, that meets industry needs.

The majority of large client projects entertained today are seeking options for renewable energy access, which is a key driver for EKPC's sustainable energy goals. EKPC and its owner-member Cooperatives have access to electricity generated from a variety of sources, including conventional and renewable sources. As sustainable and renewable energy sources become more and more available, local cooperatives are plugged in and ready to deliver energy in the way members and clients want at the lowest costs available. EKPC has embraced a diverse energy portfolio. One example of this commitment is the Cooperative Solar Farm One, one of the largest solar projects in Kentucky. Located in Winchester, Kentucky, the 60-acre farm features 32,300 solar panels producing enough electricity for 1,000 Kentucky homes. Additionally, EKPC operates six plants that generate renewable power from methane gas at landfills. EKPC also purchases hydropower from the federal Southeastern Power Administration through their Cumberland River dam system.

EKPC currently does not offer funding for site certifications programs. A highly respected national site selector firm recently informed EKPC they do not accept site certifications in their process. They have found many times certifications are misleading and inaccurate. EKPC has seen recent examples of certifications performed on Eastern

Kentucky sites proven inaccurate. Two different companies announced projects that were canceled as they performed enhanced core drilling and environmental phases for construction. EKPC prefers at this time, to work closely with property owners and provide tools like PowerVision, PowerMap, Statebook etc. that give companies a wide range of resources to make informed decisions.

Demand Side Management

- **EKPC should continue to report, annually, on its DSM programs' energy savings and peak demand deductions.**

  EKPC produces a DSM Program Annual Report each year containing energy and demand impacts per program. Please find the DSM Annual Reports for 2019, 2020, and 2021 in the technical appendices of this filing.

- **EKPC should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. EKPC should also be mindful of the increasing saturation of EE products, and be watchful for the opportunity to scale back on programs offering incentives for behavior that may be dictated by factors other than the incentives.**

  EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the California tests for cost-effectiveness. For any DSM program expansion or additions, EKPC will provide detailed support including cost-effectiveness results. Because of the GDS Energy Efficiency and Demand Response Potential Report and interactive meetings with the EKPC Sustainability Collaborative, EKPC is considering only minor changes to the existing DSM programs to improve program operations.

- **The commission recommends that EKPC continue the stakeholder process through the collaborative and strive to include recommendations and inputs from the stakeholders. These meetings should be more than informational, and entail fluid**

dialog between all vested parties. Any changes to the DSM program must be discussed in full, including a transparent analysis of the cost and benefits inputs.

EKPC re-engaged the public interest groups and other interested parties in 2021 and established the EKPC Sustainability Collaborative. A new charter for the Collaborative was created with its primary purpose of promoting participation in demand side management, energy efficiency, renewable energy, and beneficial electrification programs offered by EKPC and EKPC's owner-member cooperatives. The table in section 1.9 identifies the organizations participating in the Collaborative.

- **As required by the IRP regulation, 807 KAR 5:058, Section 7(4)(d), EKPC should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

For the GDS Energy Efficiency and Demand Response Potential Study along with more detailed California tests performed at a program level by consultant John Farley, EKPC DSM program inputs were based on actual energy and demand savings along with associated costs.

- **EKPC should continue to report on updates to bidding its peak savings from DSM programs into the PJM capacity markets.**

EKPC continues to evaluate options for monetizing the energy efficiency DSM programs in the PJM wholesale markets. Energy Efficiency is eligible to participate only in the RPM capacity market. At maximum, Energy Efficiency may receive compensation for four delivery years of capacity value if it were planned and not yet implemented before the start of the first delivery year for which it would clear in the market. For EKPC, participation in the RPM capacity market would not provide monetary value to offset any implementation costs. Because EKPC territory is a single zone in the PJM region, and no other load serving entities serve load in our zone, we would derive no financial compensation from our Energy Efficiency clearing in the market. To be able to treat Energy Efficiency (a load reducer) as a supply resource that competes against generation, PJM scales up the load in the zone. Effectively, the energy efficiency would be an offset to the load allocated to us. Moreover, participation could be a cost because PJM has established measurement and verification requirements to ensure that the Energy Efficiency provides the capacity value for which it would be paid. Those requirements are complex, and EKPC would incur a cost to produce the required evaluation and reports.

Supply-side and Demand-Side Resource Assessment

- **EKPC should continue to stay abreast of changes in Federal regulations and rule changes within PJM that have or could impact EKPC's operations and participation in PJM markets and services. In its next IRP, EKPC should report on any changes at the federal level and at PJM that have or could potentially affect EKPC since the last IRP filing and how it has or plans to respond.**

EKPC works extensively to plan for and mitigate current and future risks present in the federal policy space that could impact its operations and stays abreast of developments and changes to the federal landscape that could impact its participation in PJM. Since the filing of EKPC's last IRP in 2019, the federal landscape has shifted significantly with a changeover in presidential administrations and a shift in power in the United States Congress, both of which have impacted federal policy posture towards the electric power sector. This is most apparent in a renewed increased push towards decarbonization of electric power, including a pledge by President Biden to reduce greenhouse gas emissions by 50 percent by 2030 and 100 percent by 2050; as well as increased emphasis on deployment of renewables, and a move toward greater expansion of electric vehicles ("EV") with associated investments in EV infrastructure.

Currently, there are two large federal legislative initiatives that should be discussed in the context of impacts to EKPC:

- **Federal Infrastructure Package.** On November 15, 2021, Congress passed and the president signed into law the Infrastructure Investment and Jobs Act. This legislation contains $1 billion dollars dedicated to infrastructure improvements and investments throughout the United States, a significant portion of which is tabbed for renewable energy projects and energy efficiency measures, as well as substantial investments in EV infrastructure.

Electric Vehicle investments. The bill specifies $7 billion for EV infrastructure. Even in the absence of federal policy investments in coming years, the U.S. electric vehicle market is expanding rapidly and there will be increased infrastructure demand in Kentucky particularly along highway corridors within EKPC territory. This, plus any associated demand for EV infrastructure by Kentuckians, will take careful planning to adapt for future load growth. While projected adoption of EVs is predicted to be slower in Kentucky in comparison to other states (and in particular EKPC territory), EKPC recognizes that even modest increases in EV load in concentrated areas could provide challenges and opportunities for EKPC and its owner-members. We are closely monitoring and planning, in consultation with other utilities and the Kentucky Energy and Environment Cabinet, for this potential new load to minimize peak demands on EKPC and its owner-member systems.

Energy efficiency. The infrastructure law also contains numerous provisions related to energy efficiency including monies to state energy offices, local energy efficiency and conservation block grants, monies for efficiency improvements at small manufacturing plants, and millions of other dollars aimed at increasing energy efficiency. It also includes $3.5 billion for low-income home weatherization. Kentucky, and Kentucky-based recipients are likely to receive a portion of these federal monies. While EKPC supports energy efficiency improvements, as the law is implemented and monies distributed, EKPC will continue to monitor how this could impact load.

Resources for grid modernization. The bill contained $5 billion for resiliency grants to supplement existing grid hardening efforts and to promote grid resiliency, as well as a separate pot of money for cybersecurity for electric cooperatives. EKPC is still awaiting additional information as to how these resources will be distributed and for what specific purposes the dollars can be used.

EKPC continues to work with its owner-members, as well as other electric cooperatives within the state, and with the Kentucky Cabinet on Energy and Environment and the Kentucky Legislature, as to which opportunities to seek out and which projects make the most sense to invest in within our Integrated Resource Plan ("IRP"), as well as how monies distributed throughout the state will have an impact on EKPC and its owner-members' operations. EKPC is in the process of contracting with a dedicated consultant to help understand these opportunities fully and to provide strategic guidance to best take advantage of the resources provided under the law.

- **Build Back Better Framework.** In 2020, President Joe Biden put forth a framework entitled Build Back Better which was the outline for federal legislation to further, among other efforts, the administration's climate goals. Early legislative iterations of the Build Back Better plan had embraced the concept of a Clean Electricity Payment Plan ("CEPP"). In initial draft form, the CEPP would have created a carrot and stick regime to further incentivize investments in non-coal/non-natural gas sources of renewable energy. The CEPP would have required percentage based increases in incorporation of carbon-free energy sources, with payments provided for utilities that met the goals. If a utility failed to meet this goal, the utility would be required to make a payment at a cost per MWh.

EKPC has expressed concerns to federal policymakers that proposals like the CEPP are challenging because an overly aggressive timeframe of renewable integration in terms of both technological challenges and supply chain concerns greatly jeopardizes our ability to provide reliable power. For instance, the significant downward pressure by the federal government to replace our coal assets comes at a time when we are finding a renewed emphasis on our coal assets. With natural gas prices at an all-time high, we anticipate a future need for coal generation and programs like CEPP would incentivize the decreasing availability of coal which is compounded by the ongoing supply chain and workforce crisis associated with COVID-19, as well as the continued challenges associated with too-heavy reliance on non-dispatchable, non-storable energy sources like solar and wind that have been demonstrated in recent years in states like California.

In recent bill iterations, the CEPP language was dropped from the bill, with wind and solar production tax credits (with direct pay language) and monies for clean power projects for electric cooperatives staying in the bill. However, while there was significant negotiation in late 2021 on the Build Back Better plan, these talks have stalled and it is unclear what might happen legislatively on the energy front before the mid-term elections. The White House has said that it will seek to reinvigorate talks on the bill in coming weeks. Regardless, White House climate adviser Gina McCarthy said in July 2021 that "we have lots of regulatory authority that we intend to use, regardless, and we'll move forward with those efforts to try to tackle the climate crisis." Subsequently, we expect an associated increase in agency rulemaking aimed at administratively working to get the goals of the CEPP accomplished in the absence of a bill becoming law. Deeply concerning is that if the White House seeks to accomplish the goals of the CEPP through the regulatory process, it will likely lack the financial incentives that might have been available under a congressionally appropriated incentives package, which could have helped ease the transition towards the President's clean energy goals.

Any future regulatory efforts to accomplish the decarbonization goals require significant analysis of reliability and cost implications. It is critical for PJM, the regional grid operator and wholesale market administrator, to provide that important analysis. EKPC, therefore, continues to engage with policymakers and PJM to ensure that integration of renewables does not compromise grid reliability.

Additionally, EKPC continues to move forward to meet the increased demand for clean energy products among the owner-members of EKPC's owner-member distribution cooperatives. EKPC sustainability plan ensures appropriate focus on reliability and cost-effectiveness in supporting the adoption of clean energy resources into its energy supply portfolio.

Going Forward. While the political dynamics could shift in coming years, creating conflicting and uncertain policy messaging which makes devising a long-term outlook difficult, we expect the focus on renewables and decarbonization of the power sector as a nation and within PJM to continue, particularly given state policy evolution (among the 13 states and District of Columbia within the PJM region) and continued emphasis on carbon reductions by corporations and businesses seeking to invest in Kentucky and elsewhere in the PJM region. EKPC will continue to actively work with other electric utilities, businesses and industry, and regulators and lawmakers to manage EKPC's compliance strategies while minimizing costs to EKPC's owner-members, and continuing to provide the reliable power Kentuckians rely on.

- **EKPC should continue to stay abreast of changes in Federal regulations and rule changes within PJM that have or could impact EKPC's operations and participation in PJM markets and services. In its next IRP, EKPC should report on any changes at the federal level and at PJM that have or could potentially affect EKPC since the last IRP filing and how it has or plans to respond.**

  Additional information for the above recommendation is included with the recommendation below.

- **EKPC should continue to stay abreast of Federal Energy Regulatory Commission (FERC) Orders. In its next IRP, EKPC should discuss the impact of recent FERC Orders regarding battery storage and distributed energy resources**.

  There have been numerous changes completed or initiated to PJM's market, operations and transmission planning rules, and the FERC has issued orders and completed or initiated numerous relevant rulemakings. Additionally, NERC is beginning to evaluate whether additional assessments should be performed and/or whether standards developed to enhance reliability or to address resilience. Below EKPC focuses on those most significant for EKPC's operations and market participation.

I. Introduction

Federal and state policy developments and economics are driving a transition of the U.S. electric grid. The PJM region has already undergone a significant change in its generation portfolio, and more change is expected on the horizon. EKPC actively engages in the PJM stakeholder process, and the FERC dockets related to those PJM stakeholder process matters (and occasionally federal court dockets), when EKPC believes those matters will have an impact on EKPC's generation and transmission operations or otherwise are fundamental to good market design or reliable operations and transmission planning.

Additionally, the FERC has identified a variety of wholesale electricity market -related items that it believes must be addressed (1) to ensure the markets provide non-discriminatory access for new technologies, and (2) to ensure the markets continue to provide appropriate compensation and price signals. The organized wholesale markets exist to ensure reliability, and FERC is focused on ensuring that the markets incent resource investment (maintenance of existing and development of new assets) to preserve reliability into the future. The FERC also is exploring questions around extreme weather, climate change and resilience in a rulemaking docket.

As KY PSC Staff noted in response to EKPC's 2019 IRP, the FERC has directed organized wholesale markets like PJM to revise market rules to encourage storage resource participation and to create opportunities for aggregated distributed energy resources. Even though EKPC has not and, as discussed in this IRP, is not currently planning to develop storage resources, certain merchant developers siting projects within EKPC's territory intend to develop "hybrid" resources, or what PJM calls "combination" resources – solar + battery storage. Moreover, the FERC has initiated a rulemaking that has the potential to make sweeping changes to transmission planning and cost allocation. It is too soon to know which elements of the FERC's ANOPR may proceed through the rulemaking process and become obligations for PJM and the Transmission Owners like EKPC. Any changes to transmission expansion planning and generation interconnection will impact EKPC's operations and likely costs will be borne by our owner-members.

The KY PSC Staff guidance did not address NERC. NERC's current focus on enhanced reliability or resilience may lead to future market and operational rule changes that will impact the PJM region and EKPC. EKPC notes that the NERC has recently begun to consider whether additional assessments should be performed or additional standards developed to address anticipated challenges to the ability of the nation's generation portfolio to assure reliability and to provide a measure of resilience. It is too early in the process for EKPC to provide details of this effort. However, EKPC is encouraged that the body responsible for ensuring the reliability of the bulk electric system for North America is delving into what may be required to ensure reliable delivery of power in all hours of the day and all seasons of the year. The evolving generation portfolio in PJM and across the U.S. will necessitate a change to the requirements intended to assure reliability. It is EKPC's view that its baseload generation resources and natural gas peaking units will continue to be valuable assets providing reliability and resilience attributes the grid needs now and into the future.

EKPC will factor in any additional guidance stemming from FERC's rulemaking and from NERC's efforts in future IRP submittals.

II. <u>Wholesale Electricity Markets and Generation Operations</u>

EKPC participates in every PJM administered wholesale electricity market: energy, capacity and various ancillary services markets.

EKPC provides the current status of PJM's capacity market and reserve market rule changes addressed by PJM stakeholders and the FERC. Also, described is the current PJM stakeholder process initiative to consider other market rule changes that may be needed to ensure future reliability with the evolving PJM generation portfolio in what has been called "Phase 2" of the capacity market discussions. This work is at the early stages and will be informed by PJM analysis, including the report PJM issued in December 2021, as well as any future developments in FERC rulemakings or NERC initiatives.

Additionally, to respond to KY PSC's specific request for an update on the FERC orders on storage and distributed energy resources, below are summaries of the relevant FERC orders and updates on related PJM implementation efforts.

A. **PJM Capacity Market & Phase 2 Initiative**

1. Capacity Market Minimum Offer Price Rule

PJM's capacity market includes a provision called the Minimum Offer Price Rule ("MOPR") to ensure that the capacity prices resulting from the auctions are just and reasonable and not affected by an exercise of buyer-side market power. When the MOPR is applied, it acts as a floor on the price level at which a specific resource may be offered into the auction; the offer cannot be set at a price lower than the MOPR established level. PJM and the PJM Independent Market Monitor review and approve the price floors for all capacity resources. Prior to December 2019, an electric cooperative like EKPC was exempt from the application of MOPR so long as its capacity resource portfolio was within specific net long/net short bounds when compared to its load serving capacity obligation. EKPC was able to offer its resources into the market without risk that its offers would be mitigated to a higher level (the price floor), creating a risk that the resources may not clear in the market which would leave EKPC unable to hedge the price exposure for its load serving capacity obligation.

The FERC's December 2019 order dramatically changed the MOPR provisions. Relevant to its application to EKPC, the FERC determined that capacity resource offers of electric cooperatives must be subject to the MOPR and provided a limited exemption for electric cooperative resources that had previously cleared a capacity market auction. Under this order, any resource (owned or under contract) that did not previously clear in a capacity market auction would be subject to the MOPR.

EKPC actively defended its interests in the FERC docket and initiated appeals of the various FERC orders issued in the docket. The appeals were consolidated with other parties' appeals in the 7th Circuit Court of Appeals. The appeal has been held in abeyance at the parties' agreement to allow PJM and the all stakeholders, including the parties, to consider holistic reform of the MOPR initiated in the PJM stakeholder process.

The PJM stakeholder process, using expedited rules of procedure, resulted in a proposal (narrowed MOPR) that achieved sufficient stakeholder support to file with the FERC. The proposal fully addressed EKPC's concerns, so EKPC voted for it in the stakeholder process as well as submitted comments (jointly with Buckeye and SMECO) and expert testimony in support of it at the FERC.

The four sitting FERC Commissioners were divided in their vote on the filing. Since the filing was made pursuant to Section 205 under the Federal Power Act, it went into effect by operation of law on the date by which FERC statutorily needed to act upon it -- September 29, 2021. A few parties have filed requests to FERC seeking rehearing and court appeals. EKPC intervened in the court appeal. Both the appeals of the earlier FERC orders and the appeals of the September 2021 FERC action are pending. On November 29, 2021 the FERC denied by operation of law the rehearing requests of the narrowed MOPR and parties have appealed that FERC action. The federal courts are going to allow the appeals of the recent FERC orders to be considered first, as any decision may moot the need for the court to consider the earlier line of cases.

PJM proposed an updated timeline for the 2023/24 Base Residual Auction ("BRA") and subsequent auctions to the FERC on January 21, 2022. On February 22, 2022, the FERC approved the proposal. The BRA for the 2023/2024 delivery year will take place on June 8, 2022. Ultimately, the approved timeline will allow PJM to return to a three-year-forward BRA beginning with the May 2024 BRA for the 2027/2028 delivery year. The need to delay the auctions resulted from a Dec. 2021 FERC order reversing most of the changes FERC previously approved for PJM's reserve markets. (There is an interplay between the capacity market and energy and ancillary service markets.) Additionally, PJM will need to update various parameters used in conducting the auctions, and market seller offers will need to be updated.

2. Capacity Market Phase 2 Initiative

After addressing MOPR reform, PJM initiated stakeholder discussions to address various items that affect resource adequacy in PJM. The PJM Board and stakeholders had identified a list of items that should be addressed in this initiative. Most of the items will be considered in a new task force, the Resource Adequacy Senior Task Force ("RASTF"), but other items fit more appropriately in the scope of other established PJM stakeholder groups, including the Market Implementation Committee, the Load Analysis Subcommittee, and the Operating Committee. PJM intends to communicate stakeholder progress on all items through the RASTF, and the RASTF will provide periodic reports to the Markets and Reliability Committee.

For many of these topics, the timeline for completion will be determined during the stakeholder discussion. Given the forward nature of the Base Residual Auction and the 60 day timeline for FERC to act on filings pursuant to Section 205 of the Federal Power Act, it is likely that the issues will be sequenced and addressed through multiple FERC filings should stakeholders determine changes to address the items are necessary. It is likely that the sequencing of potential filings will prioritize items that should be resolved prior to a particular future Delivery Year.

At a high level, the various items roll up into a holistic review evaluating aspects of resource adequacy assurance answering these broad questions:

- What is the appropriate reliability target?
- How do the various resources contribute to achieving the reliability target?
- What are the performance expectations of resources committed to provide capacity?
- Can the market facilitate the procurement of clean resources to satisfy state policies?
- Will any changes to RPM require changes to the Fixed Resource Requirement rules?

EKPC has not elected to satisfy its load serving capacity obligation with the Fixed Resource Requirement ("FRR"); rather it participates in the RPM capacity market. The PJM market rules require EKPC to offer all of its generation resources into the capacity market; EKPC also offers demand response into the market. The load EKPC is required to serve is included in the PJM load represented by the Variable Resource Requirement Curve, against which all the offered generation resources clear. As a Self-Supply Entity, EKPC does not actually make a market purchase to serve it load obligation. Instead, mechanically the auction accounts for EKPC's capacity supply resources that satisfy its load obligation, which is based on the load forecast and calculated reserve requirement for the delivery year, and then compensates EKPC for any additional capacity supply resources that clear in the auction. All EKPC capacity supply resources committed to serve its load obligation and any additional resources that clear in the market are committed to the PJM region to ensure resource adequacy; all committed resources are responsible to perform and produce energy when PJM needs them to ensure regional reliability. All also must offer into the Day Ahead Energy Market.

EKPC has an interest in ensuring, (1) that the reserve requirement is set appropriately to ensure reliability, (2) that its capacity supply resources are valued appropriately given their contribution to reliability assurance, and (3) that the clearing price resulting in the various capacity markets (Base Residual Auction and associated Incremental Auctions) are just and reasonable and not the result of market power. EKPC's generation and demand response assets provide a hedge against the price exposure for satisfying its load serving capacity obligation from the market. To the extent EKPC remains winter peaking and PJM remains summer peaking, EKPC has a potential to earn revenue to offset other costs of providing full requirements service to its owner-member distribution cooperatives.

The current FRR rules are an option for EKPC to satisfy its load serving capacity obligation. Initially upon integration into PJM, EKPC utilized the FRR rules the delivery years for which a Base Residual Auction had already run. EKPC has an interest in ensuring that the FRR rules are not modified in a manner that limits its ability to use them for the benefit of its owner-members should the PJM capacity market rules change in a manner that is counter to its owner-members' interests.

3. FERC Rulemaking

In early 2021, the FERC initiated a rulemaking docket focused on "modernizing electricity market design in the organized wholesale electricity markets, like PJM.[1] The FERC convened Commissioner-led technical conferences to discuss the role of the capacity market constructs in PJM, ISO New England Inc., and New York Independent System Operator, Inc. in an environment where state policies increasingly affect resource entry and exit. With respect to PJM, the FERC focused on implications of retaining the expanded minimum offer price rule (Expanded MOPR) in the PJM capacity market, as well as prospective alternative MOPR approaches. EKPC submitted comments to FERC expressing concern that the pace of change in the generation resource mix is likely to surpass the current market structures such that PJM may not have the resources available to produce energy, or reduce load, in real time with the operating characteristics that it needs to maintain reliability 24 hours a day, 7 days a week, 365 days a year. EKPC cautioned that generators with those necessary characteristics could prematurely retire if the market undervalues their contribution, just as new resources with the desired operational attributes may not enter if their attributes are not appropriately valued. EKPC also advocated in support of MOPR rules that respected the self-supply business model of electric cooperatives like EKPC.

The FERC has not issued a final rule addressing capacity market design; however, as noted above, the FERC has already considered changes to the MOPR rules in PJM's capacity market.

B. <u>PJM Reserve Market</u>

Reserves are resources that either are not currently producing energy but may turn on quickly, or are producing energy but may increase their energy production. (10 minute/30 minute response) Because PJM was concerned about its ability to maintain real-time

[1] Modernizing Electricity Market Design, Docket No. AD21-10-000 (2021).

operational reliability into the future with increasing uncertainties of load (due to the growth of Behind the Meter generation resources) and generation supply (due to the increased penetration of intermittent resources), it proposed changes to the reserve market. PJM was concerned that it did not have all the appropriate reserve products and that the market was not appropriately incentivizing resources to provide reserves when the system most needed them.

EKPC agreed that market reform was necessary to ensure future reliability. All of EKPC's available generation resources are offered into the reserve markets and provide reserves if PJM commits them or otherwise requests that they provide reserves.

After failing to achieve sufficient stakeholder approval of reforms to address PJM's concerns, PJM filed a proposal with the FERC under Section 206 of the Federal Power Act. At a high level, PJM's proposal:

(1) adjusted the reserve products so that all will be compensated, and aligned day ahead and real time products

(2) established curves that are used in establishing the clearing price which are downward sloping; the curves have a portion that prices reserves based on the probability of experiencing shortage of that reserve product in real time

The FERC approved PJM's filing in May 2020, subject to certain compliance directives. Following the experience of winter storm Uri in February 2021 and the price escalation that occurred in ERCOT, several PJM stakeholders, including EKPC, sought to ensure that the that the PJM reserve and energy markets do not result in elevated and/or sustained prices when resources participating in those markets may not be able to react to such pricing. PJM's Energy Price Formation Senior Task Force was charged with considering that possibility and developing potential market rule changes designed to prevent sustained high prices in PJM, or what some have called a "circuit breaker."

Several parties filed appeals of the various FERC orders in the PJM reserve market docket. In late summer 2021, upon the FERC's request, the court remanded the matter back to FERC. In December 2021, the FERC reversed most of the previously approved changes. Specifically, the FERC affirmed alignment of the day ahead and real time reserve products but reversed its approval of changes to the operating reserve demand curves used in establishing the clearing price of the various reserve products. That order did not specifically address some important details of the market design, such as whether the price capping provisions would be in effect. The Commission further explained that because the Remand Order affirmed "adopt[ion of] a new 30-minute Reserve Requirement and Secondary Reserve product, PJM may propose revised reserve price caps to reflect the addition of this new product."11

In response to PJM's request for clarification, the FERC in February 2022 clarified, among other things, that the December 2021 remand order did not remove certain price capping provisions applicable to PJM's reserve markets. Additionally, the FERC indicated that because the FERC approved the adoption of a new 30-minute reserve product, PJM may propose a price cap applicable to this new product. On February 22, PJM submitted its compliance filing, which included a proposed price cap for the new product, and retaining the price caps applicable to the other reserve products. The FERC has not yet issued an order on PJM's compliance filing.

It is unclear at the moment what these developments will mean for the future work efforts of the Energy Price Formation Senior Task Force.

C. **FERC Rulemaking on Energy and Ancillary Services**

The FERC expanded its focus beyond capacity markets in organized wholesale markets to energy and ancillary service markets in its "Modernizing Electricity Market Design" rulemaking noted above.[2] The FERC Staff issued a paper on potential reforms to these markets to better address changing system needs, which formed the basis of technical conferences held in the fall of 2021. EKPC has not submitted comments in that docket but notes it generally supports the comments PJM submitted in January describing how the changing energy landscape is driving a need for new market products that add flexibility.

[2] Modernizing Electricity Market Design, Docket No. AD21-10-000 (2021).

The FERC has not issued a final rule addressing energy and ancillary services.

D. **<u>Storage</u>**

1. FERC Order 841 and PJM's Implementation

The FERC's Order No. 841 required PJM to remove barriers to participation for energy storage resources in the wholesale electricity markets. At the time the order was issued, PJM was substantially compliant with two of the four requirements in Order 841, specifically:

- Energy storage resources already have full access to PJM's technology-neutral Energy, capacity and Ancillary Services markets. Batteries represent, on average, more than 80 percent of fast-responding frequency regulation resources.
- PJM has already established a low size threshold of 100 kilowatts for all resources (including energy storage) to participate in the wholesale markets.

  PJM proposed enhancing its market rules to meet the remaining two elements of the order:

- Energy storage resources can be dispatched by the grid operator and can set the wholesale market clearing price as buyers (they can already do this as sellers).
- PJM's proposal gives energy storage operators new tools to participate in markets while accounting for the physical and operational characteristics of their resources, including fast ramp times, the ability to quickly switch between charging and discharging states, and range of state of charge between charging and discharging states and continuous mode.

As part of PJM's Order No. 841 compliance filing, PJM established rules on how storage resources, including batteries, can participate in PJM's capacity market. These resources must be available to provide energy when needed in system emergencies. This is consistent with FERC's requirement that markets be resource-neutral and open to participation by batteries – or any other resource – according to its "technical capability" to provide the service in question.

The FERC largely approved PJM's compliance filing, however, it found that PJM did not satisfactorily address the capacity accreditation of storage resources. At the same time PJM needed to re-evaluate the appropriate capacity accreditation for storage resources, it was needing to consider the appropriate capacity accreditation for variable resources (e.g., solar and wind). Thus, PJM worked with stakeholders to develop an "Effective Load Carrying Capability" method of determining the capacity accreditation for storage and variable resources.

2. Effective Load Carrying Capability

As the deployment of renewable and storage resources increase throughout the electrical grid, PJM recognized the need to reconsider its methodology for establishing the accredited capacity value for these resources to account for their actual contribution to reliability when the grid needs their energy output. These resources have variable energy output or may only be able to inject energy into the grid for a limited duration of time. PJM sought to accurately measure whether the energy output to the grid aligned with when load most needed that output - during peak electricity usage periods. The approach adopted is called Effective Load Carrying Capability ("ELCC") and it relies on an "adjusted class average" approach to determining the accredited capacity value for such resources. "Class" refers to the specific technology types, which includes technologies such as solar, hydropower, wind, landfill, and battery storage. The adjusted class average approach measures the contribution to reliability of all the portfolio of resources in that class; it assigns a capacity value associated with the portfolio's contribution to meeting the PJM loss of load expectation ("LOLE") standard. The new capacity accreditation methodology also recognizes the diminishing return associated with greater levels of deployment of these resource types, ensuring that the RTO does not become over-dependent on a single resource type whose physical capabilities have inherent limitations.

The ELCC approach to capacity accreditation sets a cap or upper limit on the amount of unforced capacity that renewable and storage resources can offer to provide to the Capacity Market in any one delivery year. As penetration of ELCC Resources increase, the class ratings will decline.

The capacity value will be adjusted yearly. As more of these resources are introduced into the capacity market, the accredited capacity value for individual resources in the class will be reduced such that the entire portfolio of resources in the class does not exceed the calculated capacity value cap determined for that class. PJM will begin relying on the accreditation values that result from applying this new methodology for the 2023/2024 delivery year.

Looking ahead, some PJM stakeholders seek to apply an ELCC-type methodology to the calculation of accredited capacity values for thermal generation resources, so EKPC anticipates this will be a topic in PJM's phase 2 capacity market/resource adequacy construct discussions described above.

3. Capacity Interconnection Rights (CIRs) for ELCC resources

During the stakeholder discussions creating an ELCC methodology for storage and variable resources, it was noted that the Capacity Interconnection Rights ("CIRs") associated with such resources could be impacted should the ELCC capacity accreditation reduce their capacity value. Therefore, the stakeholders agreed to consider the impacts to CIRs in a stakeholder process at the conclusion of the ELCC stakeholder deliberations.

When PJM studies wind and solar generation resources in the generation interconnection process, its analysis is focused on the average resource outputs over the summer period consistent with the capacity accreditation methodology that preceded the use of the ELCC methodology. As a result, the associated assignment of CIRs and the design of the transmission system only support these average output levels. Moving to the ELCC capacity accreditation methodology necessitates a change in the deliverability analysis PJM must do when it studies such resources for interconnection. The potential change is under discussion in the PJM Planning Committee. Both the level of CIRs awarded and the transmission enhancement that is needed to reliably connect the ELCC resources are likely to be impacted as a result of that effort, should the FERC approve what PJM ultimately files.

E. **Distributed Energy Resource (DER) Aggregation**

FERC Order No. 2222 seeks to harness the operational and market efficiency benefits of Distributed Energy Resources ("DER") in organized wholesale electricity markets. The order recognizes individual resources do not meet the minimum size threshold for market participation, but aggregation of them would. FERC defines DERs as any resource located on the distribution system, any subsystem thereof or behind a customer meter. FERC did not prescribe which resource types may comprise an aggregation but has identified that electric storage, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment may be among those aggregators that may seek to combine in aggregations for wholesale market participation. Additionally, FERC required Regional Transmission Organizations ("RTO") like PJM to ensure there were no barriers for DER aggregation participation in any market for which those aggregations may satisfy the operational requirements for participation (energy, ancillary services, and capacity).

Much of the detail about how the Electric Distribution Companies ("EDC"), including electric distribution cooperatives, and DER Aggregators coordinate and share operational information with each other and PJM, as well as the registration and review of individual DER resources and aggregations by the EDC were not addressed by Order 2222. FERC left those details to the RTO to address in their compliance filings. Additionally, the FERC left certain aspects to the retail regulator, such as the safe, reliable interconnection of DERs.[3]

[3] *Id* at ¶ 44 ("[T]he Commission recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs. As in Order No. 841, we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.")

Order No. 2222 does not automatically apply to all distribution utilities. EKPC supported the inclusion of an "opt in" provision that would operate to not impose the Order 2222 requirement on small distribution utilities – those distribution utilities whose annual electricity usage is less than 4 million MWh. Such a provision recognizes the operational challenges and overall economic burden imposed by Order 2222. At present and for the foreseeable future, each of EKPC's owner-member distribution cooperatives meets the size threshold to be considered a small utility eligible for the "opt in."

PJM made its compliance filing on February 1, 2022. PJM requested that the rules not go into effect until 2026, in order to provide it sufficient time to ready its systems and processes to accommodate the new rules. PJM also requested that the DER aggregations be permitted to participate in the capacity market Base Residual Auction held in 2023, for the delivery year that coincides with the effective date they requested. The FERC extended the deadline for comments on PJM's compliance filing to April 2022.

Several parties have asked the FERC to hold a technical conference to evaluate Order 222 implementation across the RTOs. Not all RTOs have submitted their compliance filings, and FERC has not issued an order addressing the requests for a technical conference.

III. <u>Transmission Expansion Planning</u>

A discussion of PJM and FERC developments associated with transmission expansion planning and generation interconnection is important for a consideration of future changes that may impact EKPC's IRP. These developments are at an early stage, so EKPC has not made specific accommodation of these in this IRP. Rather, EKPC includes reference to these developments because they will have an impact in the future that EKPC intends to reflect in future IRP submittals.

PJM has the responsibility to develop a long-term, regional transmission expansion plan, and the PJM Transmission Owners, including EKPC, have an obligation to construct certain facilities included in that plan. The PJM planning process ensures reliability and seeks to mitigate transmission congestion, which is important to ensure we can deliver power reliably and economically to our owner-members.

Additionally, EKPC is required to interconnect generators that seek to connect to EKPC's transmission facilities. Thus, EKPC is impacted by the interconnection requirements.

The FERC has initiated a rulemaking that is evaluating whether changes should be made to the long-term, regional transmission expansion and local planning processes, and whether changes are merited to the interconnection process. Because the PJM interconnection queue has been significantly backlogged, PJM and its stakeholders have undertaken an effort to reform the process. Below is an update on both the broad FERC rulemaking and the PJM stakeholder process queue reform efforts.

The developments around hybrid resources and ELCC resources noted above include transmission planning implications. EKPC does not repeat those here.

A. <u>ANOPR</u>

In July 2021, FERC issued an Advance Notice of Proposed Rulemaking ("ANOPR") seeking comments on potential reform of regional and inter-regional electric transmission planning processes, generator interconnection processes, and transmission cost allocation. EKPC submitted comments in October 2021, focused on the FERC's specific inquiries into holistic approaches to planning -- including planning to address local system needs, anticipated future generation, and renewable energy zones – as well as associated cost allocation considerations.

Of most relevance to EKPC's IRP, EKPC highlighted in its FERC comments that it is an electric cooperative whose owner-members drive the need for and ultimately approve any EKPC investment in projects to address local transmission needs. As such, EKPC cautioned that any changes to how such projects are identified and approved going forward may create challenges to EKPC's ability to control the cost and implementation timing of needed projects.

Additionally, EKPC's FERC comments addressed the ANOPR's inquiry into approaches that could support the development of renewable generation more holistically than FERC perceived the ability of the current approach to generation interconnection. The current approach is based on specific generation development projects coming forth and entering the queue for study; those individual generators bear the cost of any necessary transmission enhancements to enable the power they produce to be deliverable to load in the PJM region. The ANOPR is questioning whether there may be a proactive approach to building out the transmission system in anticipation of generation projects coming forward in the future (but with no specific obligation for any such project to come forth), and whether the interconnecting generator should bear less than the full cost of the necessary transmission reinforcements. EKPC raised concerns with the suggestion that generation interconnection would be more efficient if transmission could be built out in a proactive manner in areas where certain renewable resources may eventually locate (assuming wind/solar profiles in the location). EKPC also pointed out that the ANOPR is silent on how the regions should ensure resource adequacy should there be a preference for renewable generation. The grid will need to rely on generation fueled by means other than the sun and wind for the foreseeable future and the transmission expansion policy should not create an uneven playing field for those needed resources. A renewable energy zone policy may create an unintended resource adequacy or operational reliability challenge if other resources are discouraged from interconnecting because of the market impacts associated with the preferred renewable resources.

Additionally, EKPC raised a variety of concerns related to cost allocation but does not elaborate here as they are not germane to this IRP.

Last, the ANOPR sought comments on reforms to improve the timeliness and efficiency of the process for evaluating generators connecting to the transmission system, as well as on potential changes to cost responsibility for network upgrades needed to reliably connect new generators to the transmission system. EKPC's comments agreed there are opportunities to reform the interconnection process and urged FERC to allow regions like PJM that were already in the midst of stakeholder discussions considering such reforms to move forward and not wait for the outcome of the rulemaking process to achieve important, necessary reforms. EKPC describes that PJM stakeholder process below.

B. Generation Interconnection Queue Reform at PJM

PJM made an information report filing with FERC in February 2022 providing an update on the status of its efforts to address the backlogged interconnection queue. [4] In that report, PJM indicated that it has been experiencing an increase in the number of New Service Requests received each year leading to a record-high volume of projects under study, which directly impacts, on a cascading basis, PJM's study process and timing. PJM reported that as of January 31, 2022, it has 2,494 active projects at various points in the study process representing approximately 226.5 GW.

This backlog was the impetus for PJM and stakeholders to tackle reforming the queue process. The stakeholders' goals were to: decrease each project's time in the PJM queue; provide actionable analysis results; and increase customer cost certainty relative to the existing process and any required upgrades. At a high-level, the proposed changes are focused on moving PJM from a first-in, first-out serial interconnection process to a first-ready, first-serve cycle/phase interconnection process. East Kentucky has supported this effort and these potential changes, and has supported PJM and stakeholders working toward a solution ahead of any further action FERC may take in the context of the ANOPR.

That stakeholder initiative is drawing to a close. It appears that there is sufficient stakeholder support for both the changes to the process and requirements imposed on the interconnection applicant as well for a proposal to manage the backlog through the transition to the end state new process. Stakeholder are anticipating voting on these changes in April 2022, and PJM is anticipating filing them with FERC in May 2022.

[4] PJM Interconnection, L.L.C., Docket No. ER19-1958-003 Informational Report on Interconnection Study Performance Metrics (February 14, 2022).

At this time EKPC does not expect a reliability issue to materialize from the backlog, but because of the significant delay that any new project will experience, a concern could arise if a generator needed to deactivate or repower and its replacement is delayed. Delays also may challenge the achievement of decarbonization or other sustainability goals. This backlog has created a delay in EKPC being able to transact with a third party solar developer to install a project specifically requested by a large industrial customer via the Green Power Tariff. Additional Green Power Tariff requests, along with any projects desired to meet sustainability goals, will face similar delays in project development. EKPC will stay actively involved in PJM policy and rules development in an effort to advance its ability to meet future energy and capacity needs.

- **EKPC should provide greater transparency in and discussion of its sources of data, and how that data is used and manipulated to introduce uncertainty into the model.**

  EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP. EKPC acknowledges that market and fuel prices levels at the end of March 2022 are significantly higher than they were in the Fall 2021, when EKPC developed the price assumptions for this study. The bulk of the differences would impact the short term operations, but the market is expected to eventually turn back towards the price assumptions used in the study.

- **EKPC should provide greater support for and discussion of the rationale of its choices of alternative assumptions (such as different weather assumptions in the demand and supply-side forecasts), constraints, and decision parameters programed into the RTSim production cost and optimization models. As one example, Table 8-2 on page 136 presents nine resource options offered into the RTSim production cost model. There should be a more robust detailed discussion as to why these particular options were chosen (such as cost, performance attributes, technology development, current and expected market characteristics) and why specifically other optional resources were rejected. In addition, EKPC should provide more explicit explanations for what**

environmental cost elements and uncertainties are included in the models. EKPC should include the potential effects of carbon regulation and how that could affect fuel and emission prices on the supply-side and ultimately the price of electricity on the load forecast.

EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP.

EKPC hired Guidehouse to prepare several carbon price forecasts.

EKPC had GDS evaluate and measure cost-effectiveness of DSM and EE programs under four (4) economic scenarios:

- Base Case – EKPC's avoided costs for energy capacity from PJM
- Low Carbon – Base case plus a per MWh adder for carbon costs based on the RGGI
- Mid Carbon – Base case plus a per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus a per MWh adder for carbon costs based on the social cost of carbon in New York.

Under the Mid and High carbon cases, additional EE measures became cost-effective. The Mid case resulted in about 30% more measures being cost-effective.

- **EKPC should provide more robust and detailed explanations of the modeling results between the demand side and supply-side modeling. For example, as brought out in the Hearing, the differences between the peak load demand forecasts in Table 3-19 and those used as supply-side inputs in Table 8-6, are well reasoned, but not obvious. In addition, there should be more discussion of specific steps taken by the models to ultimately obtain a preferred least cost plan, the interactions between the RTSim models, and tying results listed in tables to discussions more closely.**

EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP. The RTSim model is discussed in the Integrated Resource Planning section.

- **If not addressed above, EKPC should provide more detailed explanations of the renewable energy resource options offered into the RTSim models. Any available production tax credit, investment tax credit, financing, or any other incentive (current or expiring should be included appropriately and explained in the model.**

  The renewable options initially considered included wind, solar, and battery storage. Solar energy, via PPAs, was the preferred resource due to cost and availability. Investment Tax Credits ("ITC") make self-build options less attractive due to the advantages a taxable entity is offered with the ITC. Wind was excluded from the screening due to the lack of significant wind resources in the EKPC zone, as noted on NREL wind speed maps, and the cost of a PPA with wind resources located in other areas of the PJM region. The transmission costs and impact of settling the PPA at the PJM AEP-Dayton Hub ("AD-Hub") and then at the EKPC zone, was cost prohibitive as compared to solar located in the EKPC zone. Battery storage has been considered for potential pilot applications, but the limited duration and initial cost has excluded batteries at this time. As the technology continues to develop and mature, EKPC anticipates further research and possible consideration of battery capacity as part of the resource portfolio.

  Solar PPAs were based on expected costs from a recent RFP for solar energy. The PPAs were allowed to annually enter into the model throughout the study period of the capacity expansion study. This allowed solar energy to be compared with market purchases and natural gas resources.

- **There are multiple pending merchant solar facilities being considered for construction and interconnection with EKPC's transmission system. EKPC should consider and discuss both the short and long-term effects of the output from the facilities on: (1) any changes in the demand for energy (and capacity if applicable) within its service territory; (2) possible changes in interest in or the expansion of the**

solar share program; (3) any effects on EKPC's and Owner-Member Distribution Cooperative's (OMDC) transmission and distribution system brought out through interconnection studies; and (4) how the sustainability goals of large customers affects EKPC's transmission and generation planning, if at all.

(1) The merchant solar facilities are not being built to serve EKPC load. However, EKPC may seek to secure via contract the output of certain of these resources in order to hedge its load position, hedge the potential for energy price volatility, and otherwise achieve its sustainability goals, as described in this IRP. These facilities may require station service power at times; however, EKPC does not anticipate a meaningful increase in energy or capacity needs as a result of the addition of merchant solar facilities.

(2) EKPC continually monitors the solar share program and the interest in that program. Based on participation to date, EKPC does not anticipate expanding that program within the planning horizon of this IRP.

(3) Regarding any effects on EKPC's and its OMDC's combined transmission and distribution systems brought out through interconnection studies, the PJM study process as described in the PJM Operating Agreement, Schedule 6, and the PJM Open Access Transmission Tariff, Parts IV and VI, is utilized by PJM, and supported by EKPC, to determine the impacts of potential newly-interconnected generation facilities on the EKPC transmission system.[5]

For each requested interconnected facility, EKPC assesses the transmission infrastructure required for:

- direct connection to the EKPC system (which is typically either a new transmission substation or expansion of an existing transmission substation)
- non-direct connection needs to attach to the EKPC system (typically includes transmission line modifications near the point of interconnection, system protective

[5] If EKPC were not in PJM, it anticipates it would have seen an increased interest in solar development in Kentucky as it currently is experiencing because the interest is largely influenced by federal policies, including PURPA.

relay upgrades at existing substations in the vicinity, and establishment of communications pathways to the point of interconnection)

- o network system upgrades needed to attach to the EKPC system (infrastructure additions and/or modifications to address overloaded EKPC transmission facilities due to increased power flows caused by the interconnected generation facility)

The facilities that are identified by EKPC for each generation interconnection are required to be constructed prior to the facility beginning commercial operations in the PJM market. This process evaluates the impacts of each project and ensures that the necessary facilities are installed to maintain a reliable and adequate EKPC transmission system while the generating facility is operating.

To assess longer-term impacts, both PJM and EKPC include interconnection queue projects with executed Interconnection Service Agreements in the long-term planning models that are used for evaluation of the transmission system through various planning studies. This ensures that any additional changes to the transmission system that are necessary to maintain adequacy and reliability are identified as the overall system changes in the future, while ensuring that the system is not overbuilt to accommodate generation projects that may not be developed.

To date, all solar generation facilities that have requested interconnection within the EKPC system have specified connection to the EKPC transmission system. Therefore, no impacts on the distribution systems of the EKPC owner-members have been identified. EKPC and its owner-members are beginning to assess general requirements for interconnection of facilities at the distribution level in anticipation of future interest by developers for smaller-scale projects with low interconnection costs. The assessment of these types of interconnection requests will evaluate both the immediate requirements and the longer-term impacts of the interconnected facilities.

(4) Regarding how the sustainability goals of large customers affects EKPC's transmission planning, EKPC has not made any changes to our process. The existing PJM study process provides a robust evaluation that covers potential dedicated renewable energy delivery to industrial customers served by EKPC owner-members. The PJM studies consider

deliverability of output of each potential interconnected facility in the PJM footprint to each load deliverability area, including EKPC. This ensures that necessary transmission infrastructure is identified and constructed to allow delivery of any generation in the PJM market to the EKPC load zone. Therefore, EKPC utilizes the existing PJM study process to determine specific infrastructure additions and modifications necessary to deliver energy from potential interconnected generation facilities to customers within the PJM zone. Furthermore, as described in the response to part (3) above, EKPC includes all generation facilities with executed Interconnection Service Agreements in our long-term planning models in order to identify any additional infrastructure requirements as the system continues to evolve, which ensures continued deliverability to EKPC customers for these facilities.

The sustainability goals of large customers can impact EKPC's generation planning. If large customers desire a specific green energy resource, EKPC will look to provide that resource to the customer as long as the specific customer incurs any additional costs associated with the request. EKPC will supply the green energy requests so long as the remainder of EKPC's customers are held harmless from any additional costs associated with the request.

EKPC, in concert with its owner-member cooperatives, developed programs and resulting tariffs to support those efforts. The Renewable Energy Program tariff was expanded to include two (2) new renewable energy options targeted to the commercial and industrial ("C&I") end-use members:

- Option B – Long-term Renewable Resources
- Option C – C&I RECs

The goal of the new program is to offer C&I end-use members renewable resources and/or Renewable Energy Credits ("RECs") to achieve their sustainability goals without cross-subsidization from or to non-participants. The Commission approved both Option B and Option C of the Renewable Energy Program tariff.

EKPC and its owner-member cooperatives have discussed the program with several large C&I end-use members. To date, one has already agreed to participate in the long-term renewable energy program. EKPC is working to secure the renewable resource as defined in the agreement. Another large C&I end-use member has agreed to a REC-only purchase. That business is offsetting 10% of its monthly consumption through RECs.

- **EKPC should continue to provide short descriptions of federal and state environmental rules and requirements that apply to it. Additionally, EKPC should clearly distinguish between: (1) rules and requirements with which EKPC is already in compliance; (2) expected changes to rules and requirements that would have a material effect on EKPC's operations and how its operations would be affected; and (3) rules and requirements with which EKPC is not yet in compliance.**

(1) See Section 9.1.

(2) and (3) In Section 9.2 EKPC has identified future rules from the EPA and Whitehouse Unified Agenda pending further action by the United States Executive Branch, Office of Management Budgets ("OMB") and the federal Environmental Protection Agency ("EPA"). The future rules could have a material impact to the generation and transmission assets but the rules have not been publicized nor have they appeared in the federal registry. Therefore, EKPC is not in compliance nor is it required to comply with the future rules just yet.

SECTION 3.0

LOAD FORECAST

SECTION 3.0

LOAD FORECAST AND LOAD RESEARCH ACTIVITIES

3.1 Summary

EKPC's load forecast is prepared every two years in accordance with EKPC’s Rural Utilities Service (“RUS”)-approved Load Forecast Work Plan (“Work Plan”). EKPC’s “2021 - 2035 Load Forecast” was prepared pursuant to its Work Plan, which was approved by RUS in December 2019. The Work Plan details the methodology used to develop the forecasts. The EKPC Load Forecasting Department works with the staff of each owner-member to prepare sixteen (16) owner-member forecasts and then aggregates the resulting forecasts, adds projections of use of EKPC facilities and transmission losses, incorporates energy efficiency and demand response impacts resulting in EKPC’s total system forecast. The load forecast was approved by the EKPC Board in December of 2020 and RUS in January 2021. Owner-Members use their load forecasts as input in developing construction work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast for demand-side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.

Due to the pandemic in 2020, this load forecast was produced later in the year than typical. SARS-CoV-2 (“COVID-19”) began impacting Kentucky’s economy in March of 2020. In an effort to better understand the near and longer-term impacts of the pandemic, EKPC opted to wait until updated economic forecasts became available. IHS Global Insight, Inc. (“IHS”) released an updated outlook in June 2020. EKPC’s load experienced its greatest reduction in April 2020 at an estimated 14%, weather normalized. Business and school closings and other government-imposed restrictions continued to impact the load in 2020. Having actual energy data for most of 2020, energy for 2020 was estimated outside of the construct of the model using insights from the owner-members and analysis of recent impacts due to COVID-19. To prevent skewing the growth rates, 2020 has been excluded from the calculations.

EKPC's load forecast projects total energy requirements to increase from 14.4 to 16.8 million MWh, an average of 1.1 percent per year over the 2022 through 2036 period. Net winter and summer peak demands will increase by approximately 277 MW or 0.6 percent and 294 MW or 0.8 percent respectively over weather-normalized 2022 to 2036. Annual load factor projections are increasing from 50 percent to approximately 54 percent from 2022 to 2036. Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2022 through 2036 period, sales to the residential class will increase by 0.7 percent per year, commercial and industrial sales ≤1000 KVA will increase by 0.8 percent per year, and commercial and industrial sales >1000 KVA will increase by 1.9 percent per year. Growth rates are shown in Table 3-1.

Table 3-1
Projected Energy and Peak Demand Growth
Compound Annual Rates of Change

	2022 - 2036
Net Total Energy Requirements	1.1%
Residential Energy Sales	0.7%
Commercial and Industrial ≤ 1000 KVA Energy Sales	0.8%
Commercial and Industrial > 1000 KVA Energy Sales	1.9%
	2022 - 2036
Net Winter Peak Demand	0.6%
Net Summer Peak Demand	0.8%

Historical and projected total energy requirements, seasonal peak demands, and annual load factor for the EKPC system are presented in Table 3-2.

Factors considered in preparing the forecast include: national, regional, and local economic performance; population and housing trends; service area industrial development; electric prices; household income; appliance saturations and efficiencies; demand-side management programs; and weather.

The load forecast includes the impacts of a 5-year DSM plan, which consists of existing DSM programs and assumes no new programs and no new participants after the fifth year. Table 3-3 shows the DSM impact on energy requirements and peak demands for the 5-year plan. Class sales are shown in Table 3-4.

Table 3-2
Historical and Projected Peak Demands and Total Requirements

Season	Winter Peak Demand (MW)	Year	Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
2009 - 10	2,868	2010	2,443	2010	13,376,292	53.2%
2010 - 11	2,891	2011	2,388	2011	12,666,998	50.0%
2011 - 12	2,481	2012	2,354	2012	12,190,070	55.9%
2012 - 13	2,597	2013	2,199	2013	12,644,590	55.6%
2013 - 14	3,425	2014	2,192	2014	13,163,516	43.9%
2014 - 15	3,507	2015	2,179	2015	12,604,942	41.0%
2015- 16	2,890	2016	2,293	2016	13,039,953	51.4%
2016 - 17	2,871	2017	2,311	2017	12,680,111	50.4%
2017 - 18	3,437	2018	2,375	2018	13,576,581	45.1%
2018 - 19	3,073	2019	2,366	2019	13,140,304	48.8%
2019 - 20	2,723	2020	2,312	2020	12,786,403	53.5%
2020 - 21	2,862	2021	2,450	2021	13,529,377	54.0%
2021 - 22	3,309	2022	2,500	2022	14,421,062	49.8%
2022 - 23	3,363	2023	2,574	2023	15,191,270	51.6%
2023 - 24	3,384	2024	2,612	2024	15,304,776	51.5%
2024 - 25	3,391	2025	2,623	2025	15,397,278	51.8%
2025 - 26	3,409	2026	2,634	2026	15,500,370	51.9%
2026 - 27	3,427	2027	2,651	2027	15,604,583	52.0%
2027 - 28	3,457	2028	2,669	2028	15,747,490	51.9%
2028 - 29	3,470	2029	2,684	2029	15,849,209	52.1%
2029 - 30	3,480	2030	2,695	2030	15,945,207	52.3%
2030 - 31	3,494	2031	2,707	2031	16,058,087	52.5%
2031 - 32	3,520	2032	2,726	2032	16,227,680	52.5%
2032 - 33	3,533	2033	2,742	2033	16,339,247	52.8%
2033 - 34	3,556	2034	2,761	2034	16,491,095	52.9%
2034 - 35	3,578	2035	2,780	2035	16,647,000	53.1%
2035 - 36	3,586	2036	2,794	2036	16,838,980	53.5%

Table 3-3
Impacts of Demand Response and Energy Efficiency Programs
Load Forecast 5-Year Plan

Year	Energy (MWH)	Winter Peak (MW)	Summer Peak (MW)
2022	-35,631	-238	-237
2023	-41,647	-239	-238
2024	-47,662	-240	-238
2025	-53,678	-241	-239
2026	-59,432	-242	-240
2027	-65,186	-243	-240
2028	-70,940	-244	-241
2029	-75,579	-245	-241
2030	-80,218	-246	-241
2031	-84,857	-246	-242
2032	-89,496	-247	-242
2033	-94,135	-248	-243
2034	-98,774	-249	-243
2035	-103,413	-249	-243
2036	-101,652	-249	-243

A separate DSM plan was developed for inclusion in the capacity plan as a resource that includes new participants in new and existing programs. Details are in Section 5.0 - Demand Side Management of this report.

Table 3-4
Class Sales

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Public Street and Highway Lighting (MWh)	Total Retail Sales (MWh)
2010	7,388,901	13,959	1,935,479	39,809	2,845,857	9,503	12,233,507
2011	6,967,413	12,774	1,892,090	38,468	2,889,142	9,845	11,809,733
2012	6,577,784	227	1,883,241	35,194	2,901,688	9,600	11,407,734
2013	6,909,853	300	1,917,730	37,215	3,017,925	9,845	11,892,868
2014	7,142,350	370	1,919,198	39,753	3,246,287	9,916	12,357,874
2015	6,781,622	354	1,958,109	38,996	2,979,716	9,890	11,768,687
2016	6,847,090	416	1,951,787	37,627	3,296,495	9,940	12,143,355
2017	6,502,113	534	1,896,475	36,578	3,395,430	9,325	11,840,456
2018	7,324,079	621	1,962,505	41,142	3,425,613	8,796	12,762,756
2019	7,036,916	663	1,925,821	39,829	3,314,391	8,770	12,326,390
2020	6,915,401	662	1,791,061	34,187	3,251,726	8,771	12,001,809
2021	7,205,739	744	1,967,078	39,064	3,546,763	8,707	12,768,095
2022	7,241,094	787	2,015,313	39,744	4,322,510	8,714	13,628,162
2023	7,250,544	830	2,043,245	39,984	5,044,551	8,724	14,387,878
2024	7,284,706	875	2,062,484	40,066	5,097,698	8,751	14,494,581
2025	7,302,221	921	2,079,718	40,009	5,149,693	8,788	14,581,351
2026	7,342,156	970	2,097,729	40,027	5,187,514	8,817	14,677,212
2027	7,391,408	1,024	2,108,594	40,062	5,224,687	8,845	14,774,619
2028	7,466,896	1,079	2,125,152	40,080	5,266,542	8,872	14,908,621
2029	7,507,069	1,126	2,142,182	40,010	5,303,801	8,898	15,003,086
2030	7,543,995	1,172	2,153,353	39,979	5,345,551	8,923	15,092,974
2031	7,583,918	1,222	2,170,018	39,974	5,394,473	8,949	15,198,554
2032	7,665,895	1,274	2,188,051	40,009	5,453,316	8,974	15,357,518
2033	7,710,245	1,325	2,204,658	39,993	5,495,901	8,999	15,461,120
2034	7,797,053	1,374	2,215,933	40,003	5,550,228	9,024	15,613,616
2035	7,876,640	1,427	2,236,079	40,019	5,596,044	9,049	15,759,257
2036	7,991,693	1,487	2,256,693	40,086	5,640,411	9,074	15,939,443

Note: Owner-Members' Form 7 data for 2021 were not available.

Table 3-4 continued
Total Sales and Requirements

Year	Total Retail Sales (MWh)	Owner-Member Office Use (MWh)	Average Distribution Losses (%)	Average Distribution Losses (MWh)	Sales to Owner-Members (MWh)	EKPC Facilities Use (MWh)	Transmission Losses (%)	Average Transmission Losses (MWh)	Net Total Requirements (MWh)
2010	12,233,507	10,401	4.4%	567,997	12,811,906	8,654	4.3%	555,732	13,376,292
2011	11,809,733	9,742	3.8%	469,596	12,289,071	10,146	3.0%	367,781	12,666,998
2012	11,407,734	9,120	4.4%	526,552	11,943,406	8,811	2.0%	237,853	12,190,070
2013	11,892,868	9,977	4.0%	498,059	12,400,903	8,270	1.9%	235,416	12,644,590
2014	12,357,874	10,497	4.1%	530,031	12,898,402	8,246	2.0%	256,868	13,163,516
2015	11,768,687	10,008	4.3%	524,746	12,303,441	8,190	2.3%	293,311	12,604,942
2016	12,143,355	10,270	4.1%	520,618	12,674,244	8,203	2.7%	357,506	13,039,953
2017	11,840,456	9,992	4.0%	490,346	12,340,793	8,374	2.5%	330,944	12,680,111
2018	12,762,756	10,647	3.5%	465,363	13,238,766	8,451	2.4%	329,364	13,576,581
2019	12,326,390	10,232	3.6%	462,149	12,798,772	7,891	2.5%	333,641	13,140,304
2020	12,001,809	9,444	3.9%	488,649	12,499,902	9,444	2.1%	277,057	12,786,403
2021	12,768,095	10,408	3.8%	449,737	13,228,240	8,250	2.4%	292,887	13,529,377
2022	13,628,162	10,408	3.8%	475,329	14,113,899	8,250	2.3%	298,913	14,421,062
2023	14,387,878	10,408	3.8%	481,691	14,879,977	8,250	2.3%	303,043	15,191,270
2024	14,494,581	10,408	3.8%	481,307	14,986,296	8,273	2.3%	310,207	15,304,776
2025	14,581,351	10,408	3.8%	485,187	15,076,946	8,250	2.3%	312,082	15,397,278
2026	14,677,212	10,408	3.8%	490,330	15,177,950	8,250	2.3%	314,170	15,500,370
2027	14,774,619	10,408	3.8%	495,025	15,280,053	8,250	2.3%	316,280	15,604,583
2028	14,908,621	10,408	3.8%	501,016	15,420,045	8,273	2.3%	319,172	15,747,490
2029	15,003,086	10,408	3.8%	506,231	15,519,725	8,250	2.3%	321,234	15,849,209
2030	15,092,974	10,408	3.8%	510,397	15,613,779	8,250	2.3%	323,178	15,945,207
2031	15,198,554	10,408	3.8%	515,412	15,724,373	8,250	2.3%	325,464	16,058,087
2032	15,357,518	10,408	3.8%	522,585	15,890,511	8,273	2.3%	328,896	16,227,680
2033	15,461,120	10,408	3.8%	528,312	15,999,840	8,250	2.3%	331,157	16,339,247
2034	15,613,616	10,408	3.8%	524,589	16,148,613	8,250	2.3%	334,232	16,491,095
2035	15,759,257	10,408	3.8%	531,696	16,301,361	8,250	2.3%	337,389	16,647,000
2036	15,939,443	10,408	3.8%	539,581	16,489,432	8,273	2.3%	341,275	16,838,980

Note: Owner-Members' Form 7 data for 2021 were not available. Distribution and Transmission losses exclude direct serve customers.

3.2 Load Forecast

3.2.1 Introduction

The forecast used in the IRP was approved December 2020 by the EKPC Board of Directors and by RUS in January 2021. It was prepared pursuant to its "2021 - 2035 Load Forecast Work Plan," which was approved by RUS in December 2019. Where available, actual data replaced forecasted values. For instance, 2020 total requirements, peaks and energy and 2021 peaks are examples of situations where actual data replaced forecasted values. Adjustments have been made to reflect more current assumptions. Specifically, the expansion of an industrial customer has been delayed over a year. The general steps followed in developing the load forecast include:

1. Develop regional economic projections: EKPC subscribes to IHS, in order to analyze regional economic performance. IHS provides county-level projections for population, employment, income as well as other variables. EKPC further analyzes the data to appropriately reflect the owner-members' individual service territories.
2. Perform analysis and construct models: EKPC prepares a preliminary forecast for each of its owner-members for each classification as reported on the RUS Form 7, which contains retail sales data for owner-members. These classes include: residential, seasonal, small commercial, public buildings, large commercial, and public street and highway lighting. EKPC's sales to owner-members are then determined by adding distribution losses to total retail sales. EKPC's total requirements are estimated by adding transmission losses to total owner-member sales. Seasonal peak demands are developed using historical normalized peaks and seasonal load factors.
3. Collect insights from the owner-members: EKPC meets with each owner-member to discuss their preliminary forecast. Owner-Member staff at these meetings includes the President/CEO and other key individuals.
4. Revise the forecasts: The preliminary forecast is revised based on the mutual agreement of EKPC staff and owner-member's President/CEO and staff. This final forecast is approved by the Board of Directors of each owner-member.
5. Develop the system load forecast: The EKPC forecast is the summation of the forecasts of its sixteen (16) owner-members with demand response, energy efficiency, transmission losses and EKPC facilities' use incorporated.

There is close collaboration and coordination between EKPC and its owner-members throughout this process. This working relationship is essential because EKPC has no retail customers. Input from owner-members relating to industrial development, subdivision growth, and other specific service area information is crucial to the development of accurate forecasts. Review meetings provide opportunities to critique the assumptions and the overall results of the preliminary forecast. The resulting load forecast reflects a combination of EKPC's structured forecast methodology combined with the judgment and experience of the owner-member staff.

3.2.2 Input Assumptions Overview

Key assumptions used in developing the EKPC and owner-member load forecasts are:

1. EKPC's owner-members will add almost 54,000 residential customers during the 15-year forecast period. This represents an increase of 0.7 percent per year.

2. EKPC uses an economic model in developing its load forecast. The county-level projections from IHS are segmented into regions using a geographic information system, ESRI, to represent owner-members' territories. This method is used to carve out the owner-member's portion of the county-level data resulting in forecasts that are more representative of the individual owner-members. The economy of these counties will experience modest growth over the forecast period. Employment forecasts show modest growth, with an average growth rate of 0.7 percent per year through the forecast period. Regional households are projected to grow at an average of 0.7 percent per year through the forecast period. Included in the Load Forecast Appendix is a report from IHS describing the short-term outlook for Kentucky.

3. As of 2020, approximately 76 percent of all new households have electric heat and about 86 percent of all new households have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.

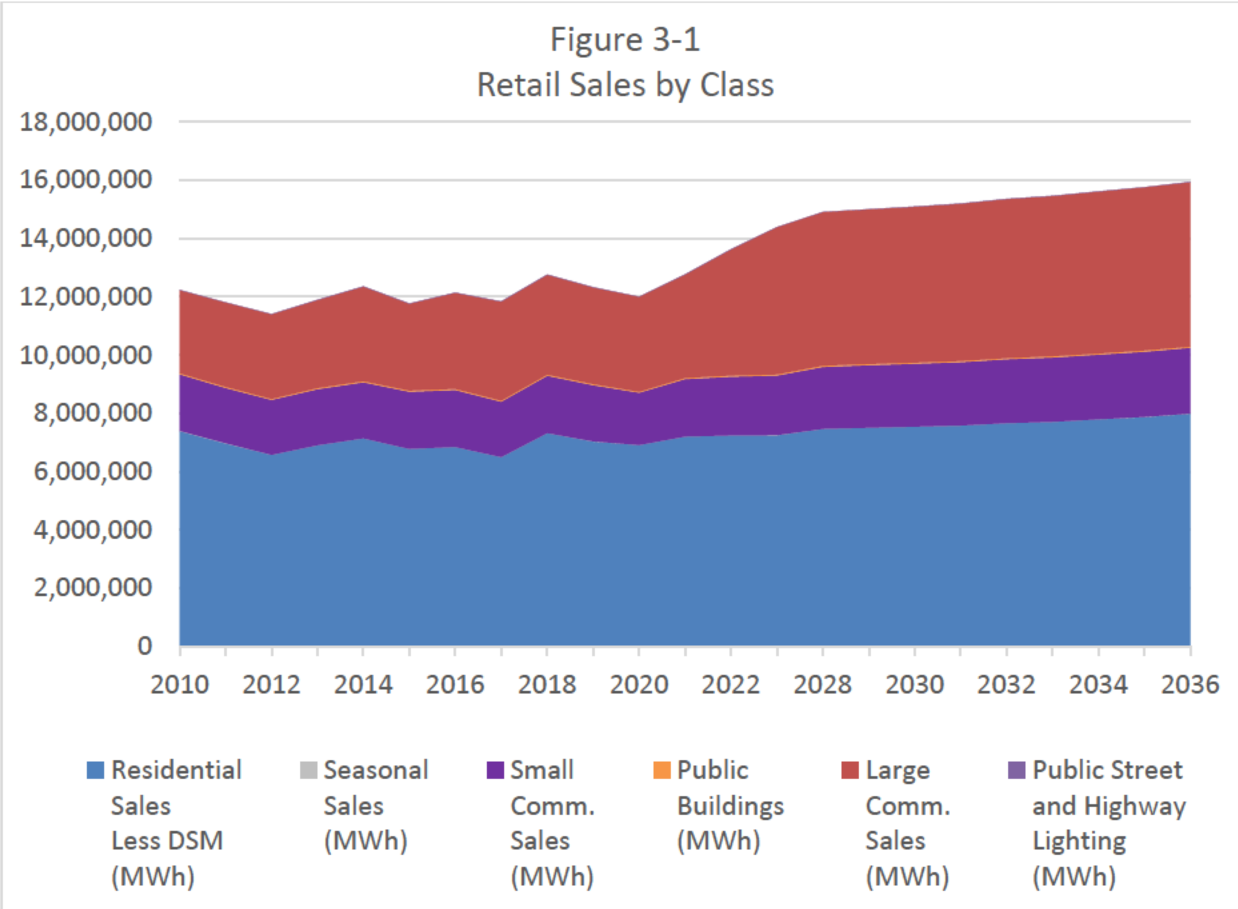
4. Over the forecast period, naturally occurring appliance efficiency improvements will have a dampening effect on residential retail sales. In addition to lighting, appliances particularly affected are heating and cooling.

5. Residential customer growth and local area economic activity are the major determinants of small commercial growth.

6. Forecasted load growth is based on the assumption of normal weather, as defined by the 20 years of historical data (2000 – 2019). Seven different stations are used depending on geographic location of the owner-member. These stations include; Lexington (“LEX”), Louisville (“SDF”), Covington (“CVG”), Jackson (“JKL”), Somerset (“SME”), Bowling Green (“BWG”), and Huntington West Virginia (“HTS”).

3.2.3 Discussion of Service Area

In EKPC’s service area, electricity is the primary method for water heating and home heating. Around 86 percent of all homes have electric water heating, and about 63 percent use electricity as a primary fuel for heating. In 2020, nearly 58 percent of EKPC’s owner-member retail sales were to the residential class and residential customer use averaged 1,121 kWh per month. Figure 3-1 illustrates the class allocations of total energy sales.



The economy of EKPC's service area is quite varied. Areas around Lexington and Louisville have a significant amount of manufacturing industry. The region around Cincinnati contains a growing number of retail trade and service jobs. Mining has seen strong decreases due to regulatory changes as well as decreased gas prices, the most notable impacts being in the eastern and southeastern regions. Tourism is an important aspect of EKPC's southern and southwestern service area, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. Kentucky as a whole expects to see growth in the health care sector due to the aging population.

3.2.4 Historical Data and Forecast Results

Table 3-5 displays energy sales in the last five years by customer class. Table 3-6 gives the weather normalized coincident peak demands of the previous five years. Table 3-7 displays weather normalized and actual energy sales and requirements for 2016 through 2020. Tables 3-8 and 3-9 display historical summaries of energy sales and coincident peak demand for firm contractual commitments and interruptible contracts, respectively. Figure 3-2 shows historical load duration curves for 2016 through 2020.

Table 3-5
EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh)
2016 - 2020

	2016	2017	2018	2019	2020
Total Residential	6,847,090	6,502,113	7,324,079	7,036,916	6,915,401
Residential Seasonal	416	534	621	663	662
Small Commercial	1,951,787	1,896,475	1,962,505	1,925,821	1,791,061
Large Commercial/ Industrial	3,296,495	3,395,430	3,425,613	3,314,391	3,251,726
Public Authorities	37,627	36,578	41,142	39,829	34,187
Public Street and Highway Lighting	9,940	9,325	8,796	8,770	8,771
Total Sales	12,143,355	11,840,456	12,762,756	12,326,390	12,001,809
Office Use	10,270	9,992	10,647	10,232	9,444
Distribution % Loss	4.1%	4.0%	3.5%	3.6%	3.9%
EKPC Sales to Owner-Members	12,674,244	12,340,793	13,238,766	12,798,772	12,499,902
EKPC Office Use	8,203	8,374	8,451	7,891	9,444
Transmission Loss (%)	2.7%	2.5%	2.4%	2.5%	2.1%
Net Total Requirements	13,039,953	12,680,111	13,576,581	13,140,304	12,786,403

Note: ***Owner-Members' Form 7 data for 2021 were not available.***

Table 3-6
Weather Normalized Coincident Peak Demands

Year	Season	Actual Peak MW	Adjusted Peak MW
2016	Winter	2,890	3,002
	Summer	2,293	2,384
2017	Winter	2,871	3,135
	Summer	2,311	2,421
2018	Winter	3,437	3,349
	Summer	2,375	2,363
2019	Winter	3,073	3,380
	Summer	2,366	2,440
2020	Winter	2,723	3,144
	Summer	2,312	2,459

Table 3-7
EKPC Weather Normalized Annual Energy Sales (MWh) and Energy Requirements (MWh)
2016 - 2020

	2016	2017	2018	2019	2020
Total Retails Sales by Owner-Member System					
Recorded	12,143,355	11,840,456	12,762,756	12,326,390	12,001,809
Weather Normalized	12,533,452	12,495,139	12,937,696	12,792,825	12,762,891
EKPC					
Recorded	13,039,953	12,680,111	13,576,581	13,140,304	12,786,403
Weather Normalized	12,895,262	12,838,462	13,267,758	13,134,522	13,064,550

Note: ***Owner-Members' Form 7 data for 2021 were not available. Data is not normalized by class.***

Table 3-8
Energy Sales and Firm Coincident Demand

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Energy Sales (MWh)*	12,674,244	12,340,793	13,238,766	12,798,772	12,499,902	NA
Coincident Peak Demand (MW)**	2,783	2,760	3,323	2,927	2,611	2,726

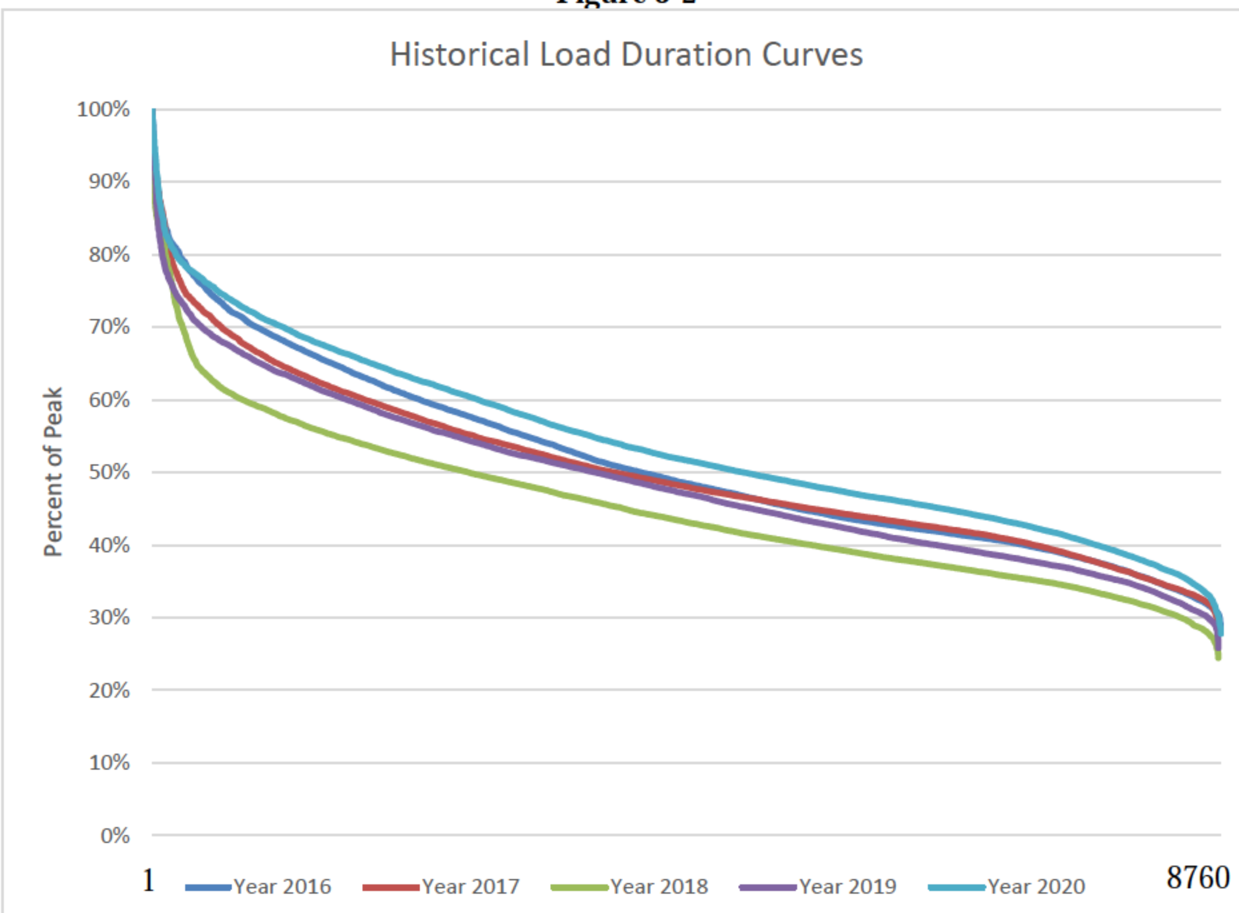
* Total sales to owner-members.
** Firm peak demand.

Table 3-9
Energy Sales and Non-Firm Demand

	2016	2017	2018	2019	2020	2021
Energy Sales (MWh)*	NA	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	107	111	114	146	112	136

* Interruptible energy is not recorded separately. Decrease in sales due to interruption is negligible.

Figure 3-2



807 KAR 5:058 Section 7(5) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:

These sections are not applicable as EKPC is not part of a multistate integrated utility system.

Customer class growth rates and annual energy growth rates are reported in Table 3-10. Forecasted monthly sales for the first two years of the forecast are presented by class in Table 3-11.

Table 3-10
Average Growth Rates
2022-2036

	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
Customers	0.7%	4.6%	0.8%	1.3%	0.3%	0.5%	0.7%
Sales	0.7%	4.6%	0.8%	1.9%	0.3%	0.01%	1.1%

Table 3-11
Monthly Class Energy Sales Forecasts
2022 – 2023

		Sales (MWH)							Peak Demand (MW)
Year	Month	Residential	Seasonal	Small Commercial	Public Buildings	Large Commercial & Industrial	Public Street & Highway Lighting	Total Retail	System Coincident
2022	1	867,693	49	172,646	3,769	360,565	738	1,405,460	3,309
	2	775,770	46	164,226	4,173	333,029	736	1,277,980	3,080
	3	635,116	42	158,717	3,672	358,428	726	1,156,703	2,716
	4	484,407	34	156,549	3,250	355,821	716	1,000,777	2,175
	5	448,990	64	157,956	2,738	369,851	716	980,314	2,097
	6	523,540	108	169,433	3,028	367,235	712	1,064,056	2,446
	7	608,550	106	182,450	3,003	373,893	711	1,168,714	2,500
	8	622,138	105	189,555	3,265	382,170	715	1,197,948	2,391
	9	514,404	76	177,538	3,585	369,132	722	1,065,456	2,498
	10	454,610	57	163,230	3,159	365,576	731	987,362	2,251
	11	554,877	48	157,548	2,860	339,056	745	1,055,135	2,681
	12	751,000	52	165,464	3,241	347,753	747	1,268,259	3,013
Total		7,241,094	787	2,015,313	39,744	4,322,510	8,714	13,628,162	
2023	1	861,513	53	174,882	3,781	420,758	738	1,461,725	3,363
	2	796,922	50	168,761	4,185	388,644	737	1,359,299	3,190
	3	657,082	47	162,657	3,715	418,243	727	1,242,471	2,860
	4	503,927	36	158,478	3,266	415,358	717	1,081,782	2,315
	5	449,767	66	159,893	2,759	431,610	717	1,044,811	2,244
	6	508,610	112	171,463	3,049	428,555	712	1,112,500	2,574
	7	590,515	110	184,531	3,026	436,362	712	1,215,257	2,474
	8	609,790	109	191,708	3,287	445,937	716	1,251,548	2,410
	9	509,410	78	179,526	3,604	430,747	723	1,124,087	2,517
	10	458,427	60	165,014	3,179	426,582	731	1,053,993	2,259
	11	556,660	52	159,154	2,879	395,846	746	1,115,336	2,697
	12	747,921	56	167,178	3,255	405,909	748	1,325,068	2,997
Total		7,250,544	830	2,043,245	39,984	5,044,551	8,724	14,387,878	

3.3 Details of Assumptions

3.3.1 Regional Economic Model

EKPC combines county-level forecasts from IHS's county-level economic forecasts released in the second quarter of 2020, into regional economic forecasts based on owner-member service territory boundaries. EKPC calculates each owner-member's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecasted residential customer count by the total number of households in the region. The share is then applied to all economic variables (including households, employment, population, real gross county product and total real personal income) before they are used in other models. Table 3-12 shows how counties are assigned to regions.

Table 3-12
Regional Economic Model, Counties by Region

Central South	Central North	South	Central	North	North East	East
Allen	Bullitt	Adair	Anderson	Boone	Bath	Bell
Barren	Hardin	Boyle	Bourbon	Bracken	Boyd	Breathitt
Butler	Henry	Casey	Clark	Campbell	Carter	Clay
Cumberland	Jefferson	Garrard	Fayette	Carroll	Elliott	Estill
Edmonson	Larue	Green	Franklin	Gallatin	Fleming	Floyd
Grayson	Meade	Lincoln	Harrison	Grant	Greenup	Harlan
Hart	Nelson	Marion	Jessamine	Kenton	Lawrence	Jackson
Metcalfe	Oldham	McCreary	Madison	Owen	Lewis	Johnson
Monroe	Shelby	Pulaski	Mercer	Pendleton	Mason	Knott
Simpson	Spencer	Russell	Scott		Menifee	Knox
Warren	Trimble	Taylor	Woodford		Montgomery	Laurel
	Washington	Wayne			Nicholas	Lee
					Powell	Leslie
					Robertson	Letcher
					Rowan	Magoffin
						Martin
						Morgan
						Owsley
						Perry
						Pike
						Rockcastle
						Whitley
						Wolfe

3.3.2 Electric Appliance Saturation and Efficiency Trends

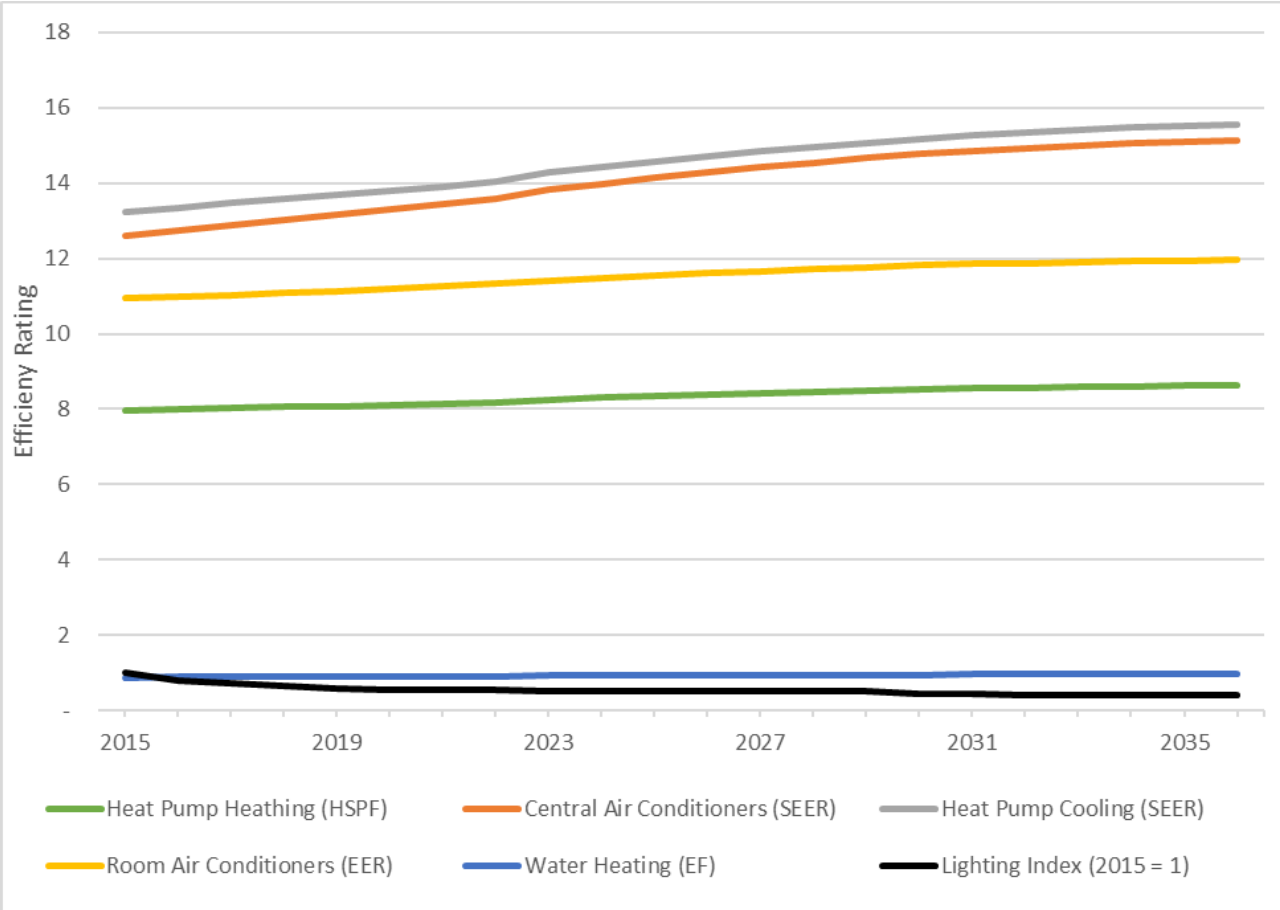
Every 2-3 years since 1981, EKPC has surveyed its owner-members' residential customers to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each owner-member. Input from owner-members and other EKPC departments is sought during the development of the survey instrument. This year questions regarding ownership of electric vehicles and interest in purchasing one were included. The "2020 Load Forecast" incorporates appliance saturations into the models. The major drivers are:

- 63 percent of EKPC customers have electric as a primary fuel for heat.
- 98 percent of EKPC customers have some type of air conditioning.
- 86 percent of EKPC customers have electric water heaters.

As previously mentioned, EKPC is a member of Itron's Energy Forecasting Group and as such, receives electric appliance efficiency projections for the East South Central U.S. Census Division (which comprises the states of Alabama, Kentucky, Mississippi, and Tennessee) based on information from the Energy Information Administration ("EIA"). Figure 3-3 displays the EIA efficiency projections. Additional details are provided in the Load Forecast Appendix.

Figure 3-3

Electric Appliance Efficiency Trends



3.3.3 Electricity Rates

The wholesale power cost projections used in the "2020 Load Forecast" are based on EKPC's board approved "Twenty-Year Financial Forecast, 2015-2034." These are layered with the owner-member distribution adders and price elasticities to develop the resulting year-over-year rate changes. Based on previous research studies and benchmarking, the elasticity assumptions for the residential class is between -.20 and -.30 and for commercial and industrial -.05 to -.15.

3.3.4 Weather

The forecasts rely on National Oceanic and Atmospheric Administration ("NOAA") weather stations located at seven airports in or near the EKPC system. Normal weather data for owner-members are based on the historic 20-year values (2000-2019). EKPC uses the following weather stations:

- Blue Grass Airport ("LEX") in Lexington, KY
- Bowling Green/Warren County Regional Airport ("BWG") in Bowling Green, KY
- Cincinnati/Northern Kentucky International Airport ("CVG") in Covington, KY
- Huntington Tri-State Airport ("HTS") in Huntington, WV
- Julian Carroll Airport ("JKL") in Jackson, KY
- Louisville International Airport ("SDF") in Louisville, KY
- Pulaski County Airport ("SME") in Somerset, KY

3.4 Discussion of Models

3.4.1 Forecast Model Summary

Models are used to develop the load forecast for each owner-member for each class reported to RUS. Model specifications are included in the Load Forecast Technical Appendix.

3.4.1.1 Residential Sales

EKPC models the monthly residential customers and monthly residential energy sales as a function of various economic variables where appropriate. These variables include:

- Customer and energy sales history
- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms, which account for historical error for a certain number of months

3.4.1.2 Small Commercial Sales

EKPC models the monthly small commercial customers and monthly small commercial energy sales as a function of various economic variables where appropriate. These variables include:

- Customer and energy sales history
- Residential customer counts
- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms, which account for historical error for a certain number of months

3.4.1.3 Large Commercial and Industrial Sales

EKPC models the monthly large commercial and industrial customers based on input from the individual owner-members and monthly large commercial and industrial energy sales are modeled as a function of the real gross county product for that given service territory. Owner-Members remain in regular contact with their largest customers and are generally aware of current production and future expansion plans, so they project energy sales for existing customers and identified expected new customers in this class for the next 3 years.

3.4.1.4 Seasonal Sales

Seasonal sales are made to customers with seasonal accounts such as vacation homes and weekend retreats and camps. Seasonal sales are relatively small and, as of 2020, only one owner-member reports seasonal residential customers.

3.4.1.5 Public Building Sales

Public Building sales include sales to accounts such as government buildings and libraries. The sales are relatively small and, as of 2020, only two owner-members report public building customers.

3.4.1.6 Public Street and Highway Lighting Sales

This class is relatively small and is projected as a function of residential sales. There are 11 owner-members that report this class.

3.4.1.7 Peak Demand

Forecasted seasonal peak demands are calculated by applying load factors for winter and summer to total purchased power for each owner-member.

3.5 Forecast Model Results

3.5.1 Residential Sales Forecast

As of 2020, residential customers account for 58 percent of total energy sales at the EKPC system level. The average number of residential customers served by EKPC's owner-members is expected to increase from approximately 521,000 in 2022 to 575,000 in 2036. Sales to the residential class are expected to grow 0.7 percent per year during the forecast period. Projected average monthly use per customer remains relatively flat throughout the forecast period. Residential sales are not classified into heating and non-heating. Table 3-13 displays the results.

Table 3-13
Residential Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	481,825	1,298	0.3	1,278	101	8.5	7,388,901	599,759	8.8
2011	482,351	526	0.1	1,204	-74	-5.8	6,967,413	-421,487	-5.7
2012	487,793	5,442	1.1	1,124	-80	-6.6	6,577,784	-389,629	-5.6
2013	489,738	1,945	0.4	1,176	52	4.6	6,909,853	332,069	5.0
2014	491,776	2,038	0.4	1,210	35	2.9	7,142,350	232,497	3.4
2015	494,297	2,521	0.5	1,143	-67	-5.5	6,781,622	-360,728	-5.1
2016	497,803	3,506	0.7	1,146	3	0.3	6,847,090	65,468	1.0
2017	500,260	2,457	0.5	1,083	-63	-5.5	6,502,113	-344,977	-5.0
2018	505,379	5,119	1.0	1,208	125	11.5	7,324,079	821,967	12.6
2019	508,475	3,096	0.6	1,153	-54	-4.5	7,036,916	-287,163	-3.9
2020	514,043	5,568	1.1	1,121	-32	-2.8	6,915,401	-121,515	-1.7
2021	517,009	2,966	0.6	1,161	40	4	7,205,739	290,338	4.2
2022	521,049	4,040	0.8	1,158	-3	0	7,241,094	35,355	0.5
2023	524,917	3,868	0.7	1,151	-7	-1	7,250,544	9,450	0.1
2024	528,726	3,809	0.7	1,148	-3	0	7,284,706	34,162	0.5
2025	532,583	3,857	0.7	1,143	-6	0	7,302,221	17,516	0.2
2026	536,459	3,876	0.7	1,141	-2	0	7,342,156	39,935	0.5
2027	540,328	3,869	0.7	1,140	-1	0	7,391,408	49,252	0.7
2028	544,224	3,896	0.7	1,143	3	0	7,466,896	75,488	1.0
2029	548,114	3,890	0.7	1,141	-2	0	7,507,069	40,174	0.5
2030	551,999	3,885	0.7	1,139	-2	0	7,543,995	36,925	0.5
2031	555,873	3,874	0.7	1,137	-2	0	7,583,918	39,923	0.5
2032	559,802	3,929	0.7	1,141	4	0	7,665,895	81,977	1.1
2033	563,721	3,919	0.7	1,140	-1	0	7,710,245	44,350	0.6
2034	567,644	3,923	0.7	1,145	5	0	7,797,053	86,809	1.1
2035	571,512	3,868	0.7	1,149	4	0	7,876,640	79,586	1.0
2036	575,437	3,925	0.7	1,157	9	1	7,991,693	115,054	1.5

Note: Owner-Members' Form 7 data for 2021 were not available. Beginning in 2018 there is a reclassification from Small Commercial to Residential.

3.5.2 Small Commercial Sales Forecast

Owner-Members classify commercial and industrial accounts into two groups. Customers whose annual peak demand is less than 1 MW are classified as small commercial customers and customers whose annual peak demand is greater than or equal to 1 MW are classified as large commercial/industrial customers. In 2020, there were more than 34,000 small commercial customers on the system. Customers are projected to grow to approximately 39,000 by 2036. As of 2020, small commercial customers account for 15 percent of total energy sales at the EKPC system level. Table 3-14 displays the results of the 2020 Load Forecast for the small commercial class.

Table 3-14
Small Commercial Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	32,553	173	0.5	59	4	7.3	1,935,479	148,367	8.3
2011	32,653	100	0.3	58	-1	-1.7	1,892,090	-43,389	-2.2
2012	33,069	416	1.3	57	-1	-1.7	1,883,241	-8,850	-0.5
2013	33,287	218	0.7	58	1	1.8	1,917,730	34,489	1.8
2014	33,670	383	1.2	57	-1	-1.7	1,919,198	1,468	0.1
2015	34,117	447	1.3	57	0	0.0	1,958,109	38,912	2.0
2016	34,252	135	0.4	57	0	0.0	1,951,787	-6,322	-0.3
2017	34,494	242	0.7	55	-2	-3.5	1,896,475	-55,312	-2.8
2018	34,199	-295	-0.9	57	2	3.6	1,962,505	66,030	3.5
2019	34,517	318	0.9	56	-1	-1.8	1,925,821	-36,684	-1.9
2020	34,741	224	0.6	52	-4	-7.1	1,791,061	-134,760	-7.0
2021	35,054	304	0.9	56	4	7.7	1,967,078	168,316	9.4
2022	35,341	287	0.8	57	1	1.8	2,015,313	48,234	2.5
2023	35,644	303	0.9	57	0	0.0	2,043,245	27,932	1.4
2024	35,929	285	0.8	57	0	0.0	2,062,484	19,239	0.9
2025	36,211	282	0.8	57	0	0.0	2,079,718	17,234	0.8
2026	36,507	296	0.8	57	0	0.0	2,097,729	18,011	0.9
2027	36,805	298	0.8	57	0	0.0	2,108,594	10,866	0.5
2028	37,093	288	0.8	57	0	0.0	2,125,152	16,558	0.8
2029	37,374	281	0.8	57	0	0.0	2,142,182	17,030	0.8
2030	37,658	284	0.8	57	0	0.0	2,153,353	11,171	0.5
2031	37,945	287	0.8	57	0	0.0	2,170,018	16,665	0.8
2032	38,240	295	0.8	57	0	0.0	2,188,051	18,033	0.8
2033	38,535	295	0.8	57	0	0.0	2,204,658	16,607	0.8
2034	38,827	292	0.8	57	0	0.0	2,215,933	11,275	0.5
2035	39,122	295	0.8	57	0	0.0	2,236,079	20,146	0.9
2036	39,423	301	0.8	57	0	0.0	2,256,693	20,614	0.9

Note: Owner-Members' Form 7 data for 2021 were not available. Beginning in 2018 there is a reclassification from Small Commercial to Residential.

3.5.3 Large Commercial and Industrial Sales Forecast

As of 2020, large commercial and industrial customers account for 27 percent of total energy sales at the EKPC system level. In 2020, there were 165 retail customers classified as large commercial and industrial customers. Approximately half of EKPC's large commercial customers are manufacturing plants, which like the small commercial class, support the automotive industry. Table 3-15 displays the results of the 2020 Load Forecast for the large commercial and industrial class.

Table 3-15
Large Commercial and Industrial Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	125	-13	-9.4	22,767	2,246	10.9	2,845,857	13,922	0.5
2011	128	3	2.4	22,571	-195	-0.9	2,889,142	43,285	1.5
2012	130	2	1.6	22,321	-251	-1.1	2,901,688	12,546	0.4
2013	135	5	3.8	22,355	34	0.2	3,017,925	116,237	4.0
2014	136	1	0.7	23,870	1,515	6.8	3,246,287	228,362	7.6
2015	129	-7	-5.1	23,099	-771	-3.2	2,979,716	-266,571	-8.2
2016	138	9	7.0	23,888	789	3.4	3,296,495	316,779	10.6
2017	149	11	8.0	22,788	-1,100	-4.6	3,395,430	98,935	3.0
2018	153	4	2.7	22,390	-398	-1.7	3,425,613	30,183	0.9
2019	157	4	2.6	21,111	-1,279	-5.7	3,314,391	-111,222	-3.2
2020	165	8	5.1	19,707	-1,403	-6.6	3,251,726	-62,665	-1.9
2021	169	4	2.4	20,987	1,279	6.5	3,546,763	295,038	9.1
2022	173	4	2.4	24,986	3,999	19.1	4,322,510	775,746	21.9
2023	178	5	2.9	28,340	3,355	13.4	5,044,551	722,041	16.7
2024	180	2	1.1	28,321	-20	-0.1	5,097,698	53,147	1.1
2025	183	3	1.7	28,140	-180	-0.6	5,149,693	51,995	1.0
2026	185	2	1.1	28,041	-100	-0.4	5,187,514	37,821	0.7
2027	187	2	1.1	27,940	-101	-0.4	5,224,687	37,173	0.7
2028	189	2	1.1	27,865	-74	-0.3	5,266,542	41,855	0.8
2029	191	2	1.1	27,769	-97	-0.3	5,303,801	37,259	0.7
2030	193	2	1.0	27,697	-71	-0.3	5,345,551	41,750	0.8
2031	196	3	1.6	27,523	-174	-0.6	5,394,473	48,922	0.9
2032	199	3	1.5	27,404	-119	-0.4	5,453,316	58,843	1.1
2033	202	3	1.5	27,207	-196	-0.7	5,495,901	42,585	0.8
2034	204	2	1.0	27,207	0	0.0	5,550,228	54,327	1.0
2035	207	3	1.5	27,034	-173	-0.6	5,596,044	45,816	0.8
2036	208	1	0.5	27,117	83	0.3	5,640,411	44,367	0.8

Note: Owner-Members' Form 7 data for 2021 were not available.

3.5.4 Seasonal Sales Forecast

This class includes seasonal accounts such as vacation homes, weekend retreats, and camps. As of 2020, only one owner-member reports seasonal residential customers, which account for less than 0.1 percent of total energy sales at the EKPC system level. Table 3-16 displays the results of the 2020 Load Forecast for the seasonal sales class.

Table 3-16
Seasonal Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	4,490	70	1.6	259	12	5.1	13,959	879	6.7
2011	4,518	28	0.6	236	-23	-9.1	12,774	-1,185	-8.5
2012	67	-4,451	-98.5	282	46	19.6	227	-12,547	-98.2
2013	94	27	40.3	266	-16	-5.6	300	73	32.4
2014	115	21	22.3	268	2	0.9	370	70	23.5
2015	120	5	4.3	246	-23	-8.4	354	-17	-4.5
2016	125	5	4.2	277	31	12.8	416	62	17.5
2017	141	16	12.8	316	38	13.8	534	118	28.4
2018	144	3	2.1	360	44	14.0	621	88	16.4
2019	150	6	4.2	368	8	2.3	663	41	6.6
2020	161	11	7.3	343	-25	-6.9	662	-1	-0.1
2021	170	10	6.3	365	14	4.1	744	71	10.6
2022	180	10	5.9	364	-1	-0.2	787	43	5.7
2023	191	11	6.1	362	-2	-0.6	830	43	5.5
2024	203	12	6.3	359	-3	-0.8	875	45	5.5
2025	214	11	5.4	359	-1	-0.2	921	46	5.2
2026	225	11	5.1	359	1	0.2	970	49	5.3
2027	238	13	5.8	358	-1	-0.3	1,024	53	5.5
2028	251	13	5.5	358	0	-0.1	1,079	55	5.4
2029	262	11	4.4	358	0	0.0	1,126	47	4.4
2030	273	11	4.2	358	0	-0.1	1,172	46	4.1
2031	284	11	4.0	358	1	0.2	1,222	50	4.2
2032	295	11	3.9	360	1	0.4	1,274	52	4.3
2033	307	12	4.1	360	0	-0.1	1,325	51	4.0
2034	317	10	3.3	361	2	0.4	1,374	49	3.7
2035	329	12	3.8	361	0	0.0	1,427	53	3.8
2036	340	11	3.3	364	3	0.8	1,487	60	4.2

Note: Owner-Member Form 7 data for 2021 was not available. As of 2012, one owner-member ceased reporting residential seasonal customers.

3.5.5 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. As of 2020, only two owner-members report this class, which account for 0.3 percent of total energy sales at the EKPC system level. Table 3-17 displays the results of the 2020 Load Forecast for the public building sales class.

Table 3-17
Public Building Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	1,046	48	4.8	3,172	207	7.0	39,809	4,301	12.1
2011	1,084	38	3.6	2,957	-214	-6.8	38,468	-1,341	-3.4
2012	1,096	12	1.1	2,676	-281	-9.5	35,194	-3,274	-8.5
2013	1,109	13	1.2	2,796	121	4.5	37,215	2,021	5.7
2014	1,117	8	0.7	2,966	169	6.1	39,753	2,537	6.8
2015	1,132	15	1.3	2,871	-95	-3.2	38,996	-757	-1.9
2016	1,137	5	0.4	2,758	-113	-3.9	37,627	-1,369	-3.5
2017	1,156	19	1.7	2,637	-121	-4.4	36,578	-1,049	-2.8
2018	1,165	9	0.8	2,943	306	11.6	41,142	4,563	12.5
2019	1,166	1	0.1	2,847	-96	-3.3	39,829	-1,313	-3.2
2020	1,174	8	0.7	2,427	-420	-14.7	34,187	-5,642	-14.2
2021	1,178	7	0.6	2,763	210	8.2	39,064	3,178	8.9
2022	1,184	6	0.5	2,797	34	1.2	39,744	680	1.7
2023	1,190	6	0.5	2,800	3	0.1	39,984	240	0.6
2024	1,197	7	0.6	2,789	-11	-0.4	40,066	82	0.2
2025	1,203	6	0.5	2,771	-18	-0.6	40,009	-58	-0.1
2026	1,209	6	0.5	2,759	-12	-0.5	40,027	18	0.0
2027	1,216	7	0.6	2,745	-13	-0.5	40,062	35	0.1
2028	1,222	6	0.5	2,733	-12	-0.4	40,080	18	0.0
2029	1,228	6	0.5	2,715	-18	-0.7	40,010	-70	-0.2
2030	1,235	7	0.6	2,698	-17	-0.6	39,979	-30	-0.1
2031	1,241	6	0.5	2,684	-13	-0.5	39,974	-5	0.0
2032	1,247	6	0.5	2,674	-11	-0.4	40,009	34	0.1
2033	1,254	7	0.6	2,658	-16	-0.6	39,993	-16	0.0
2034	1,260	6	0.5	2,646	-12	-0.5	40,003	10	0.0
2035	1,266	6	0.5	2,634	-12	-0.4	40,019	15	0.0
2036	1,273	7	0.6	2,624	-10	-0.4	40,086	67	0.2

Note: Owner-Members Form 7 data for 2021 were not available.

3.5.6 Public Street and Highway Lighting Sales Forecast

This class represents street lighting. As of 2020, 11 owner-members report public street and highway lighting customers, which account for 0.07 percent of total energy sales at the EKPC system level. Table 3-18 displays the results of the 2020 Load Forecast for the other sales class.

Table 3-18
Public Street and Highway Lighting Class
Historical and Projected Customers and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2010	423	-1	-0.2	22	-1,759	-98.7	9,503	438	4.8
2011	416	-7	-1.7	24	1	5.3	9,845	342	3.6
2012	414	-2	-0.5	23	0	-2.0	9,600	-245	-2.5
2013	412	-2	-0.5	24	1	3.0	9,845	244	2.5
2014	408	-4	-1.0	24	0	1.7	9,916	72	0.7
2015	412	4	1.0	24	0	-1.2	9,890	-26	-0.3
2016	402	-10	-2.4	25	1	3.0	9,940	50	0.5
2017	381	-21	-5.2	24	0	-1.0	9,325	-615	-6.2
2018	390	9	2.4	23	-2	-7.9	8,796	-530	-5.7
2019	409	19	4.9	21	-1	-4.9	8,770	-25	-0.3
2020	432	23	5.6	20	-1	-5.3	8,771	1	0.0
2021	431	2	0.5	20	0	-0.4	8,707	4	0.0
2022	433	2	0.5	20	0	-0.4	8,714	8	0.1
2023	436	3	0.7	20	0	-0.6	8,724	9	0.1
2024	438	2	0.5	20	0	-0.1	8,751	27	0.3
2025	440	2	0.5	20	0	0.0	8,788	37	0.4
2026	441	1	0.2	20	0	0.1	8,817	28	0.3
2027	442	1	0.2	20	0	0.1	8,845	28	0.3
2028	444	2	0.5	20	0	-0.1	8,872	27	0.3
2029	445	1	0.2	20	0	0.1	8,898	26	0.3
2030	446	1	0.2	20	0	0.1	8,923	26	0.3
2031	447	1	0.2	20	0	0.1	8,949	25	0.3
2032	449	2	0.4	20	0	-0.2	8,974	25	0.3
2033	450	1	0.2	20	0	0.1	8,999	25	0.3
2034	451	1	0.2	20	0	0.1	9,024	25	0.3
2035	452	1	0.2	20	0	0.1	9,049	25	0.3
2036	454	2	0.4	20	0	-0.2	9,074	25	0.3

Note: Owner-Members' Form 7 data for 2021 were not available.

3.6 Peak Demand Forecast and Scenarios

3.6.1 Peak Demand and Scenario Results

In addition to the base case peak demands and energy, high and low scenarios were developed for both weather and economic scenarios. The same methodology is used to construct two new models: one reflecting assumptions that result in high usage and one with assumptions that result in low usage. Assumptions include:

1. Weather: Based on 20 years of historical heating and cooling degree day ("HDD" and "CDD") data, alternate weather projections were developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively. The resulting forecasts reflect cases assuming base case HDD +/-20% and CDD +/-30%.

2. Electric price: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates bounding the base case residential price forecast. The growth rate for the electricity rate was estimated by using high and low case forecasts for the forward market prices for energy (source: ACES Power Marketing).

3. Residential customers: In the EKPC base case, the residential growth rate is 0.7%. The basic approach to preparing high and low case scenarios for the future number of residential customers is to determine the magnitude of historical variation between long term average growth rates and higher or lower growth rates during shorter periods of time. The resulting rate of 1.2% was used to produce the high case and 0.3% was used for the low case.

4. Small and Large Commercial customer and energy: Small commercial customer growth is correlated to residential customer growth and this relationship is maintained when developing the high and low cases. The industrial class was not changed.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy and demand forecasts.

The results for Net Total Energy Requirements are shown in Table 3-19 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-19
Net Total Energy Requirements (GWh)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	13,455	14,243	**14,421**	14,768	15,643
2023	14,147	14,936	**15,191**	15,736	16,610
2024	14,169	14,957	**15,305**	16,035	16,909
2025	14,170	14,958	**15,397**	16,317	17,191
2026	14,180	14,968	**15,500**	16,614	17,489
2027	14,191	14,979	**15,605**	16,918	17,792
2028	14,238	15,026	**15,747**	17,269	18,143
2029	14,245	15,033	**15,849**	17,580	18,454
2030	14,245	15,034	**15,945**	17,889	18,764
2031	14,262	15,050	**16,058**	18,223	19,097
2032	14,330	15,118	**16,228**	18,626	19,500
2033	14,343	15,131	**16,339**	18,969	19,844
2034	14,392	15,180	**16,491**	19,365	20,240
2035	14,444	15,233	**16,647**	19,773	20,647
2036	14,523	15,309	**16,839**	20,245	21,116

The results for Net Winter Peak Demand are shown in Table 3-20 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-20
Net Winter Peak Demand (MW)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2021 - 22	2,902	3,297	**3,309**	3,414	3,824
2022 - 23	2,904	3,300	**3,363**	3,476	3,893
2023 - 24	2,904	3,300	**3,384**	3,538	3,962
2024 - 25	2,893	3,287	**3,391**	3,586	4,016
2025 - 26	2,890	3,284	**3,409**	3,646	4,083
2026 - 27	2,889	3,283	**3,427**	3,708	4,153
2027 - 28	2,896	3,291	**3,457**	3,783	4,236
2028 - 29	2,890	3,284	**3,470**	3,841	4,301
2029 - 30	2,882	3,275	**3,480**	3,897	4,364
2030 - 31	2,876	3,268	**3,494**	3,957	4,431
2031 - 32	2,880	3,272	**3,520**	4,032	4,515
2032 - 33	2,873	3,265	**3,533**	4,093	4,584
2033 - 34	2,874	3,266	**3,556**	4,167	4,667
2034 - 35	2,875	3,267	**3,578**	4,241	4,750
2035 - 36	2,863	3,253	**3,586**	4,302	4,816

The results for Net Summer Peak Demand are shown in Table 3-21 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-21
Net Summer Peak Demand (MW)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	2,236	2,541	**2,500**	2,631	2,947
2023	2,221	2,524	**2,574**	2,659	2,978
2024	2,240	2,546	**2,612**	2,729	3,057
2025	2,236	2,541	**2,623**	2,772	3,105
2026	2,233	2,537	**2,634**	2,816	3,154
2027	2,233	2,538	**2,651**	2,866	3,210
2028	2,235	2,540	**2,669**	2,919	3,269
2029	2,234	2,539	**2,684**	2,969	3,325
2030	2,230	2,534	**2,695**	3,016	3,378
2031	2,227	2,531	**2,707**	3,064	3,432
2032	2,229	2,533	**2,726**	3,121	3,495
2033	2,229	2,533	**2,742**	3,176	3,557
2034	2,231	2,535	**2,761**	3,234	3,622
2035	2,233	2,537	**2,780**	3,293	3,688
2036	2,231	2,534	**2,794**	3,351	3,752

3.7 Load Research and Research and Development Activities

3.7.1 Load Research

As previously stated, EKPC conducts an appliance saturation survey every two to three years. In addition, EKPC has a load research program which consists of more than 407 meters on residential, commercial and industrial retail members. EKPC and its owner-members work together to collect load research data that are needed for various analyses at the retail level, such as the design of marketing programs. Load research data are used in end-use forecasting methodologies to project energy sales and demand and also provides information for demand estimates for cost of service studies and/or rate cases for EKPC and the owner-members. Standard estimates and statistics are developed for each month of a study including:

- Class Demand at System Peak Hour
- Class Demand at Class Peak Hour
- Hourly Class Demands on System Peak Day
- Hourly Class Demands on Class Peak Day
- Coincidence and Load Factors
- Class Energy Use
- Class Non-Coincident Peak Demands
- Class Time-Of-Use statistics.

The most traditional method for obtaining load data is metering, usually with a time-of-use or load profile recording meter. To be useful statistically, however, a sample of sufficient size must be metered from owner-members' population base. The advantage of metering is that it provides results explicitly for a particular service area or rate class for a given time period (peak hour). Compared to other alternatives, this method is more expensive and generally takes a longer time to provide meaningful data; however, its reliability is relatively high. Metered data can also become outdated rather quickly, which is why EKPC maintains a continuous load research project, targeted at owner-member rate classes. EKPC has also used metering in end-use studies such as air source heat pumps, electric thermal storage, and geothermal heating and cooling systems.

Load research projects have and will continue to be a part of EKPC's research efforts. Current on-going load research projects include:

1. Residential: Includes retail members that are billed in the residential class. There are 35 load profile meters installed and collecting data.
2. Small Commercial & Industrial: These are non-residential retail members whose demand is less than 50 kW. There are 16 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes retail members whose peak demands are between 50kW and 350kW. There are 21 load profile meters installed and collecting data.
4. Large Power: Includes retail members whose peak demands are greater than 350kW. There are 335 meters installed and collecting data.

3.7.2 Research and Development

EKPC and its 16 owner-member cooperatives are actively engaged with the Energy and Environment Cabinet and the Kentucky Department of Transportation in the effort to determine locations for the EV public charging network throughout Kentucky.

EKPC and its 16 owner-member cooperatives are reviewing funding opportunities resulting from the Infrastructure Investment and Jobs Act. EKPC is working with the owner-member cooperatives to identify funding opportunities to improve electric service to the Kentuckians served.

In 2020, EKPC and two (2) owner-members offered a smart home pilot to 50 residential members of each cooperative. The goals of the pilot include the evaluation of energy and demand savings along with gauging customer acceptance. Participants utilize the Powerley App to access their usage data every 15 seconds, as well as manage energy consumption of appliances in the home. The pilot is still operational.

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

EKPC currently owns, operates and/or has firm rights to approximately 3,437MW of winter capacity. This capacity is located at 11 separate sites with a total of 25 generating units and includes a firm purchase power agreement with the Southeastern Power Administration. Fuel sources include coal, natural gas, landfill gas, solar, and hydro.

Coal Fired Units

Cooper Station

John Sherman Cooper Station located near Somerset on Lake Cumberland. The station has one 116 MW unit that became operational on February 9, 1965, and one 225 MW unit that began operating commercially on October 28, 1969. Both units are pulverized coal units. A pollution control system was added to the Cooper 2 unit and began commercial operation in summer 2012. A duct reroute project, which routes the flue gas from unit one into the unit two pollution control system, was completed in 2016.

Spurlock Station

Hugh L. Spurlock Station situated near Maysville, Kentucky on the Ohio River. The station consists of four units. The first one is a 300 MW unit that began commercial operation on September 1, 1977. Unit 2 is a 510 MW unit that began operating on March 2, 1981. Both of these units are conventional pulverized coal units with FGD technology. Spurlock 1 and 2 have had extensive modification and enhancements to comply with coal combustion residuals and effluent limitation guidelines.

On March 1, 2005, Unit 3 became operational. It is a 268 MW unit. The fourth unit became operational on April 1, 2009. It is a 268 MW unit. Both units 3 and 4 are circulating fluidized bed boiler technology.

Steam Load

International Paper has a corrugated paper recycling facility adjacent to EKPC's Spurlock Station. The facility has an expected peak electrical load of approximately 35 MW and an equivalent of 29 MW in steam. The steam is supplied from Spurlock Unit 2 on a normal basis but can also be supplied from Spurlock Unit 1 when needed. On average, International Paper operates 99 percent of the time and Spurlock 2 operates at an average of 510 MW.

Natural Gas / Fuel Oil

Peaking Capacity

EKPC has three ABB GT 11N2 combustion turbines, four General Electric Co. 7EA combustion turbines, and two General Electric Co. LMS 100 combustion turbines located at the J. K. Smith Station in eastern Clark County on the Kentucky River. The ABB turbines, which went commercial in 1999, have a summer rating of 104MW each and a winter rating of 142MW each. Two of the GE turbines went commercial in 2001 and two in 2005. Each has a summer rating of 73 MW and a winter rating of 88 MW (93MW for Unit 4). The ABB and GE turbines are all capable of firing with fuel oil as a secondary fuel supply. The two LMS 100 turbines became operational in 2010. Unit 9 has a summer rating of 75 MW and Unit 10 has a summer rating of 74 MW. They both have a winter rating of 103 MW.

EKPC expanded the peaking fleet in 2015 with the acquisition of the Bluegrass Generation Station in Oldham County. The three Siemens 501FD-2 units were commercial in 2002. The winter rating for each unit is 189 MW and the summer rating is 167 MW. In 2020, all three units were retrofitted for fuel oil as a secondary fuel supply.

Southeastern Power Administration ("SEPA")

EKPC purchases 170 MW of hydropower from SEPA on a long-term basis. Laurel Dam (70MW) has historically been a reliable resource and continues to be reliable. EKPC purchases a 100% of the energy generated at Laurel Dam. The remaining 100 MW is supplied from the Cumberland River system of hydropower projects. The Nashville District Corps of Engineers Hydropower

Program has developed a Capital Improvement Plan that covers non-routine maintenance, rehabilitation or modernization of the Cumberland River hydropower system over approximately the next 20 years. During this time, the system capacity could be less than the marketed capacity for the Cumberland customer groups as the units are taken out of service and are unavailable for generation. Reductions to capacity are reconciled through the SEPA invoicing process through providing capacity credits. Until such rehabilitation is completed to provide a total system capacity to support the customer allocations, scheduling capacities will continue to be reduced on a weekly basis according to the available system capacity.

Renewable Sources

Landfill Gas

EKPC owns and operates 16.1 MW of landfill gas capacity generated at 6 sites throughout Kentucky.

Photo Voltaic Solar

Cooperative Solar Farm One was placed into operation on November 12, 2017. It is located adjacent to EKPC Headquarters in Winchester, KY. The 60 acre farm features 32,300 solar panels capable of producing up to 8.5MW. As of year-end 2021 there were 242 subscribers with 1,492 panels.

807 KAR 5:058 Section 8.(3)(b)(1-11) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility: (1) Plant name; (2) Unit number(s); (3) Existing or proposed location; (4) Status (existing, planned, under construction, etc.); (5) Actual or projected commercial operation date; (6) Type of facility; (7) Net dependable capability, summer and winter; (8) Entitlement if jointly owned or unit purchase; (9) Primary and secondary fuel types, by unit; (10) Fuel storage capacity; (11) Scheduled upgrades, deratings, and retirement dates.

Table 4-1
Generating Plant Data

	Cooper Station		Spurlock Station			
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**	**Gilbert**	**Unit 4**
Location	Somerset, KY	Somerset, KY	Maysville, KY	Maysville, KY	Maysville, KY	Maysville, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	2/9/1965	10/28/1969	9/1/1977	3/2/1981	3/1/2005	4/1/2009
Type	Steam	Steam	Steam	Steam	Steam	Steam
Net Dependable Capability	116 MW	225 MW	300 MW	510 MW	268 MW	268 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage (Tons)	250,000 for Plant Site	250,000 for Plant Site	105,000	175,000	105,000	105,000

Table 4-2
Generating Plant Data

Smith Combustion Turbines

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7
Location	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY	Trapp, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	3/1/99	1/1/99	4/1/99	11/10/01	11/10/01	1/12/05	1/12/05
Type	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability (MW)	104 Sum 142 Win	104 Sum 142 Win	104 Sum 142 Win	73 Sum 93 Win	73 Sum 88 Win	73 Sum 88 Win	73 Sum 88 Win
Entitlement (%)	100	100	100	100	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Fuel Storage (Gallons)	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total

Table 4-3
Generating Plant Data

Smith Combustion Turbines

	Unit 9	Unit 10
Location	Trapp, KY	Trapp, KY
Status	Existing	Existing
Commercial Operation	2009	2009
Type	Gas	Gas
Net Dependable Capability (MW)	75 Sum 103 Win	74 Sum 103 Win
Entitlement (%)	100	100
Primary Fuel Type	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	N/A
Fuel Storage (Gallons)	N/A	N/A

Table 4-4
Generating Plant Data

Landfill Gas

	Bavarian	Green Valley	Laurel Ridge	Hardin Co.	Pendleton Co.	Glasgow
Location	Boone County, KY	Greenup County, KY	Laurel County, KY	Hardin County, KY	Pendleton County, KY	Barren County, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	9/22/03	9/9/03	9/15/03	1/30/06	2/1/07	12/1/15
Type	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	4.6 MW	2.3 MW	3.0 MW	2.3 MW	3.0 MW	0.9 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Methane	Methane	Methane	Methane	Methane	Methane
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage	N/A	N/A	N/A	N/A	N/A	N/A

Table 4-5
Generating Plant Data

Bluegrass Combustion Turbines

	Unit 1	Unit 2	Unit 3
Location	LaGrange, KY	LaGrange, KY	LaGrange, KY
Status	Existing	Existing	Existing
Commercial Operation	2002	2002	2002
Type	Gas	Gas	Gas
Net Dependable Capability (MW)	167 Sum 189 Win	167 Sum 189 Win	167 Sum 189 Win
Entitlement (%)	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	Fuel Oil	Fuel Oil	Fuel Oil
Fuel Storage (Gallons)	1 million total	1 million total	1 million total

Table 4-6
Generating Plant Data

Cooperative Solar

	Farm One
Location	Winchester, KY
Status	Committed
Commercial Operation	2017
Type	Solar
Net Dependable Capability	8.5 MW
Entitlement (%)	100
Primary Fuel Type	Solar

807 KAR 5:058 Section 8.(3)(b)(12) Resource Assessment and Acquisition Plan. (3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility: (12) Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars; (a) Capacity and availability factors; (b) Anticipated annual average heat rate; (c) Costs of fuel(s) per millions of British thermal units (MMBtu); (d) Estimate of capital costs for planned units (total and per kilowatt of rated capacity); (e) Variable and fixed operating and maintenance costs; (f) Capital and operating and maintenance cost escalation factors; (g) Projected average variable and total electricity production costs (in cents per kilowatt-hour).

Cooper 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Cooper 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Spurlock 1	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Spurlock 2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Gilbert Unit	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Spurlock 4	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Smith CT3	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT4	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT5	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Smith CT6	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT7	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Smith CT 9	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Smith CT 10	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Bluegrass CT1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Bluegrass CT2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

	ACTUAL															
Bluegrass CT3	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Landfill Gas Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	ACTUAL															
Future SCGT	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Availability Factor												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Heat Rate (Btu/kWh)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Cost ($/MMBtu)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M Escalation (%)												[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

SECTION 5.0

DEMAND SIDE MANAGEMENT

SECTION 5.0

DEMAND SIDE MANAGEMENT

5.1 Introduction

807 KAR 5:058 Section 8(2)(b) The utility shall describe and discuss all options considered for inclusion in the plan including: (b) Conservation and load management or other demand-side programs not already in place.

EKPC selects DSM programs to offer on the basis of meeting customer needs and resource planning objectives in a cost- effective manner. EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the California tests for cost-effectiveness.

This IRP evaluates the costs and benefits of DSM programs to be implemented by EKPC in partnership with its owner-members.

These efforts are to comply with:

> "Each electric utility shall integrate energy efficiency resources into its plan and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In each integrated resource plan, certificate case, and rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission ' s IRP regulation (807 KAR 5:058)." - *In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*, Rehearing Order, Case No. 2008-00408, p. l O (Ky. P.S.C. July 24, 2012).

5.2 DSM Planning Process

For the 2022 IRP, EKPC GDS to prepare an updated study of EE and DR savings potential. For more details on the energy efficiency and demand response measures, including the results of economic screening of those measures, please see the GDS Energy Efficiency and Demand Response Potential report (included as **Exhibit DSM-1** in the DSM Technical Appendix).

In this 2022 IRP, EKPC has again set participation levels for its DSM programs consistent with historical experience.

EKPC will allocate that funding to existing programs. No new programs are proposed in this IRP, however.

Guided by the findings in the GDS Potential Report, EKPC review the energy efficiency and demand response programs, and prepared savings, participation, and cost estimates for those programs.

EKPC then conducted a final cost-effectiveness analysis for each DSM program using the *DSMore* software tool. All of the programs were shown to be cost-effective using the TRC test.

The DSM portfolio for the 2022 IRP includes seven (7) energy efficiency programs and one (1) demand response program.

807 KAR 5:058 Section 8(3)(e)(1) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (1) Targeted classes and end-uses.

The following table provides the targeted classes and end-uses for the DSM programs included in the plan. More detailed program descriptions can be found in Exhibit DSM-5 in the DSM Technical Appendix.

Table 5-1
Existing Programs: Classes and End-uses

Program Name	Class	End-uses
Button-Up Weatherization	Residential	Space Heating, Space Cooling
CARES – Low Income	Residential	Space Heating, Space Cooling, Water Heating, Lighting
Heat Pump Retrofit	Residential	Space Heating, Space Cooling
Touchstone Energy ("TSE") Home	Residential	Space Heating, Space Cooling, Water Heating
ENERGY STAR® Manufactured Home	Residential	Space Heating, Space Cooling
Residential Energy Audit	Residential	Space Heating, Space Cooling, Water Heating, Lighting
Residential Efficient Lighting	Residential	Lighting
Direct Load Control-Residential: AC Bring Your Own Thermostat ("BYOT") [6] [7]	Residential	Space Cooling

[6] The tariff allows small commercial customers to participate. However, EKPC is not projecting to have any small commercial participants in this IRP.
[7] The Residential Direct Load Control ("DLC") program will continue to enroll both switches and thermostats. In this IRP, the savings and the costs are based on the BYOT option.

807 KAR 5:058 Section 8(3)(e)(2) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (2) Expected duration of the program.

Expected duration of the program;

The following table provides the expected duration of each program. For each program, the number of years that new participants are served is given as well as the lifetime of the measure savings:

Table 5-2
Existing Programs – Duration

Program Name	New Participants	Savings Lifetime
Button-Up Weatherization	15 years	15 years
CARES – Low Income	15 years	15 years
Heat Pump Retrofit	15 years	20 years
Touchstone Energy ("TSE") Home	15 years	20 years
ENERGY STAR® Manufactured Home	15 years	15 years
Residential Energy Audit	15 years	5 years
Residential Efficient Lighting	15 years	8 years
Direct Load Control-Residential: AC Bring Your Own Thermostat	15 years	15 years

807 KAR 5:058 Section 8(3)(e)(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (e) For each existing and new conservation and load management or other demand-side programs included in the plan: (3) Projected energy changes by season, and summer and winter peak demand changes.

The following tables provide the projected annual energy, summer peak demand and winter peak demand changes for each DSM program included in the plan. These load changes have been accounted for in the Load Forecast. The load changes capture the impacts of future participants only.

Load Impacts of DSM Programs

Button-Up Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	280	-568	-0.4	-0.1
2023	560	-1,136	-0.9	-0.3
2024	840	-1,703	-1.3	-0.4
2025	1,120	-2,271	-1.8	-0.5
2026	1,400	-2,839	-2.2	-0.7
2027	1,680	-3,407	-2.6	-0.8
2028	1,960	-3,974	-3.1	-0.9
2029	2,240	-4,542	-3.5	-1.1
2030	2,520	-5,110	-4.0	-1.2
2031	2,800	-5,678	-4.4	-1.3
2032	3,080	-6,245	-4.8	-1.5
2033	3,360	-6,813	-5.3	-1.6
2034	3,640	-7,381	-5.7	-1.7
2035	3,920	-7,949	-6.1	-1.9
2036	4,200	-8,516	-6.6	-2.0

CARES-Low Income program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	375	-1,686	-0.5	-0.2
2023	750	-3,371	-1.0	-0.5
2024	1,125	-5,057	-1.5	-0.7
2025	1,500	-6,743	-2.0	-1.0
2026	1,875	-8,428	-2.5	-1.2
2027	2,250	-10,114	-3.0	-1.5
2028	2,625	-11,799	-3.5	-1.7
2029	3,000	-13,485	-4.0	-2.0
2030	3,375	-15,171	-4.5	-2.2
2031	3,750	-16,856	-5.0	-2.5
2032	4,125	-18,542	-5.5	-2.7
2033	4,500	-20,228	-6.0	-3.0
2034	4,875	-21,913	-6.5	-3.2
2035	5,250	-23,599	-7.0	-3.5
2036	5,625	-25,285	-7.4	-3.7

Heat Pump Retrofit program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	450	-3,456	0.0	-0.2
2023	900	-6,913	0.0	-0.3
2024	1,350	-10,369	0.0	-0.5
2025	1,800	-13,825	0.0	-0.7
2026	2,250	-17,282	0.0	-0.8
2027	2,700	-20,738	0.0	-1.0
2028	3,150	-24,194	0.0	-1.1
2029	3,600	-27,650	0.0	-1.3
2030	4,050	-31,107	0.0	-1.5
2031	4,500	-34,563	0.0	-1.6
2032	4,950	-38,019	0.0	-1.8
2033	5,400	-41,476	0.0	-2.0
2034	5,850	-44,932	0.0	-2.1
2035	6,300	-48,388	0.0	-2.3
2036	6,750	-51,845	0.0	-2.5

Touchstone Energy Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	340	-1,025	-0.9	-0.2
2023	680	-2,049	-1.9	-0.5
2024	1,020	-3,074	-2.8	-0.7
2025	1,360	-4,098	-3.8	-0.9
2026	1,700	-5,123	-4.7	-1.1
2027	2,040	-6,147	-5.7	-1.4
2028	2,380	-7,172	-6.6	-1.6
2029	2,720	-8,196	-7.6	-1.8
2030	3,060	-9,221	-8.5	-2.0
2031	3,400	-10,246	-9.5	-2.3
2032	3,740	-11,270	-10.4	-2.5
2033	4,080	-12,295	-11.4	-2.7
2034	4,420	-13,319	-12.3	-2.9
2035	4,760	-14,344	-13.3	-3.2
2036	5,100	-15,368	-14.2	-3.4

ENERGY STAR® Manufactured Home Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	50	-203	0.0	0.0
2023	100	-406	-0.1	0.0
2024	150	-609	-0.1	-0.1
2025	200	-812	-0.2	-0.1
2026	250	-1,015	-0.2	-0.1
2027	300	-1,218	-0.3	-0.1
2028	350	-1,421	-0.3	-0.2
2029	400	-1,624	-0.4	-0.2
2030	450	-1,827	-0.4	-0.2
2031	500	-2,030	-0.5	-0.2
2032	550	-2,233	-0.5	-0.3
2033	600	-2,436	-0.6	-0.3
2034	650	-2,639	-0.6	-0.3
2035	700	-2,842	-0.7	-0.3
2036	750	-3,045	-0.7	-0.4

Residential Energy Audit Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	500	-247	-0.1	-0.1
2023	1,000	-493	-0.2	-0.1
2024	1,500	-740	-0.2	-0.2
2025	2,000	-986	-0.3	-0.2
2026	2,500	-1,233	-0.4	-0.3
2027	2,500	-1,233	-0.4	-0.3
2028	2,500	-1,233	-0.4	-0.3
2029	2,500	-1,233	-0.4	-0.3
2030	2,500	-1,233	-0.4	-0.3
2031	2,500	-1,233	-0.4	-0.3
2032	2,500	-1,233	-0.4	-0.3
2033	2,500	-1,233	-0.4	-0.3
2034	2,500	-1,233	-0.4	-0.3
2035	2,500	-1,233	-0.4	-0.3
2036	2,500	-1,233	-0.4	-0.3

Residential Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	5,000	-252	0.0	0.0
2023	10,000	-504	-0.1	-0.1
2024	15,000	-756	-0.1	-0.1
2025	20,000	-1,008	-0.2	-0.1
2026	25,000	-1,260	-0.2	-0.1
2027	30,000	-1,512	-0.2	-0.2
2028	35,000	-1,764	-0.3	-0.2
2029	40,000	-2,016	-0.3	-0.2
2030	45,000	-2,268	-0.3	-0.2
2031	50,000	-2,520	-0.4	-0.3
2032	55,000	-2,772	-0.4	-0.3
2033	60,000	-3,024	-0.5	-0.3
2034	65,000	-3,276	-0.5	-0.4
2035	70,000	-3,528	-0.5	-0.4
2036	75,000	-3,780	-0.6	-0.4

Direct Load Control: Residential Air Conditioner – Bring Your Own Thermostat

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	2,000	-72	0.0	-2.4
2023	4,000	-144	0.0	-4.8
2024	6,000	-216	0.0	-7.2
2025	8,000	-288	0.0	-9.6
2026	10,000	-360	0.0	-12.0
2027	12,000	-432	0.0	-14.4
2028	14,000	-504	0.0	-16.8
2029	16,000	-576	0.0	-19.2
2030	18,000	-648	0.0	-21.6
2031	20,000	-720	0.0	-24.0
2032	22,000	-792	0.0	-26.4
2033	24,000	-864	0.0	-28.8
2034	26,000	-936	0.0	-31.2
2035	28,000	-1,008	0.0	-33.6
2036	30,000	-1,080	0.0	-36.0

807 KAR 5:058 Section 8(3)(e)(4) For each existing and new conservation and load management or other demand-side programs included in the plan; (4) Projected cost, including any incentive payments and program administrative costs.

The projected costs for each DSM program are shown below in Table 5-3. Cost values are the present value of the future stream of costs for that element using a 5% discount rate. Owner-Member rebates are paid to retail member participants. More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

Table 5-3
DSM Program Costs

	Program costs present value, 2022 $ using a 5% discount rate			
Program	**Owner-Member Admin**	**EKPC Admin**	**Rebates[8]**	**Member Investment**
Button-Up Weatherization	$1,091,976	$66,644	$1,762,366	$4,357,192
CARES Low Income	$9,746,701	$262,257	$0	$4,012,531[9]
Heat Pump Retrofit	$1,221,809	$130,820	$3,239,644	$15,466,986
Touchstone Energy (TSE) Home	$1,909,230	$65,410	$3,147,083	$6,067,156
ENERGY STAR® Manufactured Home	$30,854	$229,552	$709,636	$709,636
Residential Energy Audit	$0	$1,641,420	$0	$370,245
Residential Efficient Lighting	$0	$65,410	$555,368	$449,231
Direct Load Control-Residential: AC Bring Your Own Thermostat	$0	$13,473,350	$8,972,995	$2,468,300
Totals	$14,000,569	$15,934,863	$18,387,092	$33,901,277

[8] Rebates are not included in the TRC test.
[9] The member costs for the CARES Low Income program represent the Kentucky Housing share of measure costs. This is included (along with gas savings) in order to calculate the correct TRC for the program.

The projected cost savings for each DSM program are shown below in Table 5-4. Values shown are the benefits in the Total Resource Cost test. Cost values are the present value of the future stream of costs using a 5% discount rate.

Table 5-4
DSM Program Cost Savings

		present value 2022 $
Program		**Projected Cost Savings**
Button-Up Weatherization		**$9,251,697**
CARES – Low Income		**$16,059,558** [10]
Heat Pump Retrofit		**$26,955,443**
Touchstone Energy (TSE) Home		**$16,870,385**
ENERGY STAR® Manufactured Home		**$1,575,665**
Residential Energy Audit		**$906,126**
Residential Efficient Lighting		**$2,020,012**
Direct Load Control-Residential: AC Bring Your Own Thermostat		**$34,634,303**
Total		**$108,273,189**

The Total Resource Cost test for the entire portfolio yields a benefit-cost ratio of **1.70.**

More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

807 KAR 5:058 Section 8(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan.

Please see pages 7-8 and 13-15 in the DSM technical appendix.

All DSM programs are evaluated using the standard California cost-effectiveness tests.

[10] Includes gas cost savings

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

6.1 Introduction

807 KAR 5:058 Section 8(2)(a) The utility shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Transmission System

Introduction

EKPC's transmission system is geographically located in roughly the eastern two-thirds of Kentucky. The transmission system approaches the borders of Kentucky in the north, east, and south, and stretches to the Interstate 65 corridor in the west. The system is comprised of approximately 2,968 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and includes 77 free-flowing interconnections with neighboring utilities. EKPC’s interconnections with neighboring utilities have been established to improve the reliability of the transmission system and to provide access to external generation resources for economic and/or emergency purchases. Table 6-1 lists each of EKPC’s free-flowing interconnections.

EKPC integrated into the PJM Regional Transmission Organization (“RTO”) on June 1, 2013 and participates in the PJM markets. As a result, EKPC and PJM closely coordinate transmission planning activities for the EKPC system. EKPC and PJM work together to develop transmission expansion plans to comply with applicable PJM reliability criteria through the PJM transmission planning process. To meet local needs, EKPC designs its transmission system to provide adequate capacity for reliable delivery of EKPC generating resources to its owner-members, and for long-term firm transmission service that has been reserved on the EKPC system. EKPC’s transmission planning criteria specify that the system must be designed to meet these projected demands with simultaneous outages of a transmission facility and a generating unit during peak conditions in both summer and winter.

Membership in PJM

EKPC integrated into PJM on June 1, 2013. PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electric energy market and capacity market and manages the high-voltage electricity grid to ensure reliability for more than 61 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system wide basis. PJM is registered in the SERC region for the following reliability functions as described in the North American Electric Reliability Corporation ("NERC") Reliability Functional Model for PJM Members: Balancing Authority ("BA"), Interchange Authority ("IA"), Planning Coordinator ("PC"), Reliability Coordinator ("RC"), Resource Planner ("RP"), Transmission Operator ("TOP"), Transmission Planner ("TP"), and the Transmission Service Provider ("TSP").

EKPC and PJM coordinate transmission planning activities for the EKPC system through a bottom-up/top-down approach. EKPC and PJM share responsibility for planning of the EKPC transmission system to adhere to both PJM and EKPC transmission planning criteria. The PJM criteria includes both its criteria to maintain the reliability of the Bulk Electric System ("BES") as well as criteria EKPC has established to address certain local reliability needs and which has documented in FERC Form 715. All projects addressing FERC Form 715 criteria needs must be reviewed and approved by PJM.

PJM performs all required assessments of the entire BES for its footprint to ensure conformance with its planning criteria. Transmission projects are identified throughout the RTO footprint as needed to address potential violations of these criteria. These projects are then incorporated into the transmission plans of the applicable transmission owner, thereby ensuring that these plans are considered by the transmission owner in the development of their local transmission plans. PJM thereby ensures that an appropriate transmission expansion plan, called the Regional Transmission Expansion Plan ("RTEP"), is developed for the entire region through a single planning process that provides a reliable, efficient, and economical integrated plan. PJM also coordinates its RTEP with neighboring utilities and RTOs, including MISO, LG&E/KU, and TVA to ensure interregional reliability.

With respect to local transmission plans, EKPC has established criteria to meet local planning needs not addressed by the PJM criteria or its FERC Form 715 criteria. All projects resulting from these local planning criteria are provided to PJM for inclusion in the RTEP. These are called supplemental projects. PJM verifies the need for these projects and ensures that they may reliably be incorporated into the RTEP. Moreover, the PJM planning process ensures transparency – that all projects, including local projects, are made known to the PJM stakeholder community. The local plans of EKPC and other PJM member systems are therefore rolled up into the overall regional plan.

<u>Membership in SERC Reliability Corporation ("SERC")</u>

EKPC is a member of SERC. SERC is one of six regional entities in North America that is responsible for ensuring the reliability and security of the interconnected electric grid. SERC has been delegated by the North American Electric Reliability Corporation ("NERC") to perform certain functions and is subject to oversight from the FERC. SERC promotes and monitors compliance with mandatory Reliability Standards, assesses seasonal and long-term reliability, monitors the bulk power system (BPS) through system awareness, and educates and trains industry personnel. Owners, operators, and users of the BPS in the SERC footprint cover an area of approximately 630,000 square miles. The regional entities and all members of NERC work to safeguard the reliability of the BPS throughout North America. NERC has been certified by the FERC as the Electric Reliability Organization for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 93 mandatory Reliability Standards that are in effect and subject to enforcement. EKPC is required to comply with 44 of these standards based upon its responsibility for various functions. PJM is responsible for 37 other standards on EKPC's behalf based on PJM's registration for NERC-defined reliability functions. PJM and EKPC have joint compliance responsibilities for 12 Reliability Standards and many additional standards are currently under development. PJM and EKPC continue to identify and refine planning practices that will ensure compliance with these NERC Reliability Standards.

EKPC actively participates in SERC activities and studies. Each year, EKPC participates in SERC assessments of transmission system performance for the summer and winter peak load periods. In these assessments, potential operating problems on the interconnected bulk transmission system are identified. EKPC annually supplies SERC with data needed for development of current and future load flow computer models. These models are used by EKPC and other SERC members to analyze and screen the interconnected transmission system for potential problems.

EKPC adheres to SERC's guidelines for transmission and generation planning and operations. With all of the SERC members following these guidelines, each owner-member can have a high degree of confidence that the transmission system will be adequate for the normal and emergency (outage) conditions simulated. Participation in SERC enhances the reliability of each owner-member without having to install excess generation and transmission capacity to provide a comparable level of reliability.

Interconnections

Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic/emergency generating sources. The interconnections established with other utilities generally have provided stronger sources in specific areas of need within the EKPC system. This avoids the need to construct long, high-voltage transmission lines from the EKPC system and typically reduces EKPC’s transmission-system losses.

EKPC participates in joint planning efforts with neighboring utilities to ascertain the benefits of potential interconnections, which can include increased power transfer capability, local area system support, and outlet capability for new generation. It should be noted that actual transfer capabilities are unique to real-time system conditions, as affected by generation dispatch, outage conditions, load level, third-party transfers, etc.

EKPC has established two new interconnections, a 69 kV interconnection with LG&E/KU at a new 69 kV switching station in Shelby County (July 2021), and a 161 kV interconnection with TVA at the Fox Hollow substation (January 2022). These new interconnections are needed to improve the reliability of the electric system in the area, and will have minimal power transfer benefits.

Transmission Expansion (2019-2021)

From 2019-2021, EKPC implemented various transmission projects, summarized as follows:

- Transmission station modifications
  - Two 161 kV circuit switcher additions
  - One 138 kV circuit switcher addition
  - One 161 kV breaker addition
  - Four 69 kV breaker additions
  - One 138-69 kV transformer upgrade
  - One 161 kV station upgrade
  - One 138 kV reactor upgrade
  - Addition of a 161 kV station expansion at an existing 69 kV substation
  - Addition of one 69 kV switching station
- Rebuild of existing line using larger (lower impedance, higher capacity) conductor
  - 89.73 miles – 69 kV
- Construction of 12.83 miles of new 69 kV transmission lines
- Construct 0.55 miles of new 138 kV transmission lines
- Construct 1.05 miles of new 161 kV transmission lines (2 new lines with lengths of 0.8 mile and 0.25 mile)
- High temperature upgrades of 69 kV transmission lines (6.52 miles)
- High temperature upgrades of 161 kV transmission lines (3.96 miles)

Construction of new transmission lines within the EKPC system generally has resulted in reduction of system losses.

EKPC has continued to upgrade existing transmission-line conductors primarily due to the age and condition of older transmission lines in the EKPC system. EKPC's line rebuild projects typically increase conductor capacity by 50 percent to 225 percent, depending on the sizes of the installed conductor and the replacement conductor that is used. In addition, by installing larger conductors, less voltage drop is seen on the system, deferring the need to construct new facilities to provide voltage support in an area. Transmission-system losses are also reduced due to the lower impedance of the larger replacement conductors. The amount of loss reduction varies, and is dependent on the hourly power flows on each particular line, but typical expectations for loss reduction range from 250 to 400 MWh per year when transmission line conductors are upgraded for any particular transmission line.

Future Transmission Expansion

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak-load requirements are met reliably. EKPC's Transmission Planning Department resides in our Engineering and Construction Business Unit, and works closely with other groups at EKPC to coordinate activities and address reliability issues. EKPC also seeks input from other external parties, including potential generation developers regarding issues or needs related to the EKPC transmission system. Additionally, the transmission expansion plan for the EKPC system is developed and reviewed through PJM's stakeholder process to ensure the needs of all external stakeholders are being addressed in combination with the needs of EKPC's owner-members on a comparable, non-discriminatory basis.

EKPC's transmission expansion plan includes a combination of new transmission lines and substation facilities and upgrades of existing facilities during the period from 2022 to 2036 to provide an adequate and reliable system for existing and forecasted native load members and existing and future generation resources.

Transmission expansion plans are developed and updated on an annual basis. Power-flow analysis is used to predict problem areas on the transmission system. Various alternatives for mitigating these problems are then formulated and analyzed. The transmission expansion projects that provide the desired level of reliability and adequacy at a reasonable cost are then added into the plan. Note that transmission planning, like all EKPC planning processes, is ongoing, and changing conditions may warrant changes to the transmission plan.

EKPC's transmission work plan for the period from 2022 to 2024 is based on detailed engineering analyses, and includes transmission projects that are relatively firm in nature. These projects include the construction of new substations and transmission lines, as well as upgrades of existing substations and transmission lines. These improvements will meet growing member demand, enhance system reliability, and improve the efficiency of the system. Maps of EKPC's existing transmission system and of the EKPC transmission system showing interconnected facilities plus EKPC's planned future facilities are included in Section 11 of this report.

The planned improvements to the EKPC transmission system for the period from 2022 to 2024 are summarized as follows:

- Upgrade of one existing 138-69 kV transformer
- Addition of three new 69 kV switching stations
- Upgrade of one existing 69 kV switching station
- Three 69 kV breaker additions
- Two 138 kV breaker additions
- Rebuild of 135.8 miles of 69 kV line
- Construction of 20.6 miles of new 69 kV line
- Construction of 0.6 miles of new 161 kV line

The analysis used to develop the plan beyond the first three years is typically less detailed than that used to develop the work plan for the first three years. The assumed system conditions are less certain than those used for the first three years of analysis. Many of the projects beyond the first three-year period are conceptual in nature, and are more likely to change in scope and date, or to be cancelled and replaced with a different project. EKPC's 15-year expansion plan for the 2022-2036 period is included as Table 6-2 through Table 6-11. This 15-year expansion plan includes 266.1 miles of existing line 69 kV rebuilds, 31.1 miles of new 69 kV line construction, 0.6 miles of new 161 kV line construction, and 9.8 miles of high-temperature conductor upgrades. It also includes the addition and/or upgrade of 2 transmission stations, 4 new 69 kV switching stations, the upgrade of 1 138-69 kV autotransformer, and the addition or upgrade of facilities at 7 transmission stations. It also includes the addition of 73.5 MVARs of new transmission capacitor bank capability.

Construction of new transmission lines typically improves net system losses. EKPC expects to see a net overall reduction in system losses as a result of the planned construction of 31.1 miles of new 69 kV line in the 2022-2036 period.

The planned transmission line re-conductors/rebuilds will enhance utilization of the existing transmission system by increasing the capacity of those lines. As discussed earlier, replacing existing conductors with larger conductors will also provide increased voltage support and will reduce system energy losses. Similarly, the planned upgrades of power transformers will provide more efficient system utilization by increasing capacity while reducing voltage drop and system energy losses.

Line terminal facility upgrades increase the effective thermal capacity of a transmission line to meet system needs while eliminating the need for a new line. Similarly, thermal upgrades on power transformer facility terminal equipment increase the effective thermal capacity of the facility to meet system needs while eliminating the need for a new or higher-capacity power transformer.

New switching stations increase system reliability by potentially eliminating thermal (overload) and (low) voltage problems and/or member outages associated with the loss of multiple line segments. Switching stations also increase system operational flexibility and improve system protection schemes.

New transmission substations provide strong sources (of real MW and reactive MVAR power) to the network on the low-voltage side of the new substation. Thus, the new substations provide more efficient access to available support from the existing adjacent higher voltage network.

The addition of transmission capacitor banks provides better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

Generation Related Transmission

PJM and EKPC perform studies for transmission requirements for units connected to the EKPC transmission system after an official request has been submitted per PJM Open Access Transmission Tariff requirements. Only those projects necessary for firm (committed) generation resources (existing and future) are identified in EKPC's transmission expansion plan. This includes merchant generation facilities that have completed the PJM generation interconnection study process and have subsequently executed Interconnection Service Agreements with PJM/EKPC. Once a valid application for interconnection has been submitted to PJM, the proposed generation facility begins the PJM queue study process. This process involves three study phases (Feasibility Study, System Impact Study, and Facilities Study) that include power-flow analysis, short-circuit analysis, and stability analysis to determine impacts of the requested generator interconnection on the PJM transmission system. The Facilities Study also includes engineering review to develop the scope, estimated cost, and implementation schedule for the transmission-system upgrades necessary to connect the proposed project to the PJM system. EKPC works in conjunction with PJM on these studies, particularly with regard to providing the necessary transmission system upgrades to address impacts identified during the PJM study process.

As of January 1, 2022, there were a total of 103 active merchant-generation facilities in the PJM queue that had requested interconnection to the EKPC transmission system. The total maximum output of these facilities was 8,736 MW. All of these projects are either stand-alone solar generation facilities or hybrid solar/battery storage facilities. Of these 103 total projects, six (6) projects have reached the final-agreement phase – i.e., these facilities have an executed Interconnection Service Agreement. EKPC is in process of performing engineering, procurement, and preparing for construction for these six generation facilities. EKPC will need to construct various facilities required for direct connection of the generation facilities to the EKPC transmission system, as well as perform necessary upgrades on certain transmission facilities to accommodate the expected power flows with these projects connected. The necessary facilities are summarized as follows:

- Construction of one new 138 kV switching station
- Construction of three new 69 kV switching stations
- Expansion of one existing 161/138 kV substation
- High-temperature conductor upgrades of 19.9 miles of 69 kV transmission line

Additionally, EKPC will install overhead optical ground wire (“OPGW”) for communications purposes on various line sections, and perform various protective-relay upgrades to accommodate these projects. All EKPC costs associated with the infrastructure needed to accommodate connection of generation projects to the EKPC transmission system are fully reimbursed by the generation-project developers. EKPC has not included any transmission projects in its transmission expansion plan for future generation interconnection other than those projects with executed Interconnection Service Agreements.

Import Capability

EKPC routinely assesses the ability to import power from external sources into the EKPC load zone. Import capability is assessed from regions to the north and to the south of the EKPC system as part of the normal planning process. Also, EKPC performs import capability studies as a participant in SERC's annual system assessments.

EKPC designs its transmission system to be capable of importing at least 500MW from regions either north or south of Kentucky. Import studies indicate that EKPC's import capability from the LG&E/KU interface ranges up to 850MW, depending on the time period being evaluated. EKPC imported up to 1,628 MW in 2018 during real-time operations from its PJM interface, indicating that the import capability is in that range, even during winter peak conditions. Finally, the import capability from the TVA interface ranges up to 450 MW, depending on the time period.

PJM ensures generation in PJM may be deliverable to load throughout PJM. As such, PJM ensures that transmission constraints do not prevent power from effectively flowing to load. As part of PJM's planning process, a load deliverability assessment is performed annually using a 90/10 load forecast (i.e., the load level with a 90 percent probability of the actual peak demand being lower than the forecasted value and a 10 percent probability of the actual peak demand being higher) to ensure that each load-deliverability zone within PJM (including EKPC) can meet extreme demand levels with other PJM resources (external to each zone being studied) if necessary. This helps ensure that adequate transmission infrastructure is available to utilize the PJM market efficiently and to avoid the need for an excessive amount of generation reserves within the RTO.

Although these import studies indicate that during many periods EKPC can import large quantities of power, real-time market and transmission-system conditions may result in system limitations that are significantly different from those predicted in these studies. Available Transfer Capacity (ATC) calculations are performed by Regional Transmission Organizations (such as PJM and MISO), Independent Transmission Organizations (such as the LG&E/KU ITO) and Reliability Coordinators (such as TVA). These results are coordinated to ensure that the lowest value for a particular path is set as the ATC. Such studies utilize updated data for transmission and generation outages, market transactions, and system load to predict expected system flows. Therefore, it is difficult to predict the availability of transmission capacity for imports into the EKPC system. EKPC may pursue procurement of additional amounts of transmission from other supply sources in advance of peak seasons to ensure adequate import capability.

EKPC does not typically experience import and export transmission limitations on an operational basis due to limited ATC. EKPC's membership in PJM is one of the primary reasons for the elimination of historical constraints on imports and exports.

Extreme Weather Performance

EKPC annually performs an assessment of its transmission system for both summer and winter peak conditions. EKPC evaluates its system using two load forecasts – a 50/50 probability forecast and a 90/10 probability forecast. When evaluating system performance using a 50/50 forecast, contingency analysis is also performed on the system to ensure that the system is designed to provide adequate service at this load level even with a transmission facility and/or generator out of service. EKPC presently does not perform a contingency analysis when using the 90/10 probability forecast. EKPC considers an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event. EKPC did not identify any constraints on the transmission system as part of the 2021 extreme weather analysis.

Distribution System

EKPC is an all-requirements power supplier for 16 owner-members in Kentucky. In addition to designing, owning, operating, and maintaining all transmission facilities, EKPC is responsible for all delivery points (distribution substations), including the planning of these delivery points in conjunction with the respective owner-member. EKPC monitors peak distribution substation transformer loads seasonally to identify potential loading issues for delivery points to owner-members. Furthermore, EKPC and the owner-members jointly develop load forecasts for each delivery point that are used to identify future loading issues. EKPC typically uses a four-year planning horizon for distribution substation planning. EKPC and the owner-members use a joint planning philosophy based on a "one-system" concept. This planning approach identifies the total costs on a "one-system" basis – i.e., the combined costs for EKPC and the owner-member – for all alternatives considered. Generally, the alternative with the lowest one-system cost is selected for implementation, unless there are overriding system benefits for a more expensive alternative.

EKPC delivery points were improved in the 2019-2021 period through the construction of new substations, as well as through upgrades of existing substations, to meet growing member demand in certain areas, enhance reliability and improve the efficiency of the system.

From 2019-2021, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of 6 new distribution substations
- Upgrades of 9 existing distribution substations/transformers

New distribution delivery points enhance the utilization of the existing system by providing a new injection point into the existing distribution system. This will generally provide improved system energy losses, as well as increased voltage support. Distribution substation transformer additions and upgrades of existing distribution substation transformers also improve system efficiency by increasing capacity at an existing facility rather than building new facilities. These additions/upgrades reduce system impedance at the substation, which improves voltage drop and reduces energy losses.

Further improvements are planned for EKPC's distribution substation delivery points for the 2022-2025 period. These improvements include the construction of new distribution substations, as well as upgrades of existing substations. These improvements will meet growing member demand in certain areas, enhance system reliability, and improve the efficiency of the system.

The planned improvements to EKPC distribution substations for the 2022-2025 period are summarized as follows:

- Construction of 4 new distribution substations
- Rebuild and/or upgrade of 32 existing distribution substations

These distribution substation enhancements will improve system efficiency and utilization as described above. EKPC's 15-year expansion plan for the 2022-2036 period is included as Table 6-5 through Table 6-11.

Table 6-1 (continued on next page)
EKPC Free-Flowing Interconnection Capability

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
AEP							
1	Argentum	Millbrook Park	138	170	170	170	170
2	Argentum	Grays Branch	69	42	42	54	54
3	Falcon	Falcon	69	34	34	34	34

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
4	Helechawa	Lee City	69	52	52	52	52
5	Leon	Leon	69	55	66	69	69
6	Morgan County	Morgan County	69	69	69	69	69
7	Thelma	Thelma	69	71	71	90	90
AEP Total:				545	542	611	619
DP&L							
8	Spurlock	Stuart	345	1240	1532	1684	1792
DP&L Total:				1240	1532	1684	1792
Duke Energy-OHIO/KENTUCKY (DEOK)							
9	Boone	Long Branch	138	254	284	363	387
10	Hebron	Hebron	138	229	255	332	348
11	Spurlock	Meldahl Dam	345	1274	1421	1848	1894
12	Webster Road	Webster Road	138	96	117	121	139
13	Hebron	Hebron	69	89	98	128	134
DEOK Total:				1991	2229	2862	2975
LG&E/KU							
14	Avon	Loudon Avenue	138	203	203	286	287
15	Baker Lane	Baker Lane Tap	138	215	251	279	304
16	Beattyville	Beattyville	69	94	119	144	159
17	Beattyville	Beattyville Tap	161-69	84	84	84	84
18	Beattyville-Powell Co.	Delvinta	161	219	223	239	239
19	Bekaert	West Shelby	69	89	98	128	134
20	Bonnieville	Bonnieville	69-138	89	109	112	129
21	Boonesboro Tap	Boonesboro North	138	166	210	256	283
22	Bracken Co.	Carntown	69	36	36	72	72
23	Bracken Co.	Sharon	69	53	66	81	89
24	Bullitt Co	Bullitt Tap	161	267	298	351	362
25	Bullitt Co	Cedar Grove Industrial	161	219	277	336	371
26	Central Hardin	Hardin County	138	208	265	287	287
27	Central Hardin	Blackbranch	138	229	290	352	391
28	Clay Village	Clay Village Tap	69	49	54	70	73
29	Cooper	Elihu	161	219	277	279	305
30	Duncannon Lane Tap	Fawkes	69	89	98	128	134
31	East Bardstown	Bardstown Ind.	69	67	67	86	89
32	Fawkes	Fawkes	138	229	296	287	370
33	Fawkes	Fawkes Tap	138	229	284	355	387
34	Gallatin Co.	Ghent	138	229	255	287	287
35	Garrard Co.	Lancaster	69	90	115	141	156
36	Goldbug	Wofford	69	42	46	60	63
37	Green Co.	Greensburg	69	103	108	113	116
38	Green Hall Jct.	Delvinta	161	219	251	251	251
39	Hodgenville	Hodgenville	69	73	76	86	89
40	Hodgenville	New Haven	69	73	76	86	89
41	Kargle	Elizabethtown	69	89	98	128	134
42	Laurel Co.	Hopewell	69	119	124	141	145
43	Liberty Church Tap	Farley	69	66	76	88	94

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
44	Marion Co.	Lebanon	138	192	220	264	272
45	Murphysville	Kenton	69	53	66	66	68
46	Murphysville	Sardis	69	53	66	81	89
47	Nelson Co.	Nelson Co Tap	69-138	144	152	172	178
48	North London	North London	69	73	76	86	89
49	North Springfield	Springfield	69	49	54	64	66
50	Owen Co.	Bromley	69	49	49	94	94
51	Owen Co.	Owen Co. Tap	138	194	200	219	225
52	Paris Tap	Paris	138	239	289	312	340
53	Penn	Scott Co.	69	77	90	95	100
54	Pittsburg Tap	Pittsburg	161-69	112	120	120	120
55	Renaker	Cynthiana Sw.	69	53	66	81	89
56	Rogersville Jct.	Rogersville	69	114	127	166	174
57	Rowan Co.	Rodburn	138	143	200	143	203
58	Sewellton	Union Underwear	69	77	90	95	100
59	Shelby Co.	Shelby Co. Tap	69	89	98	122	126
60	Somerset	Ferguson South	69	139	152	172	178
61	Somerset	Somerset South	69	129	133	129	133
62	South Anderson (624)	Bonds Mill (644)	69	89	98	128	134
63	South Anderson (634)	Bonds Mill (634)	69	83	98	128	134
64	Spurlock	Kenton	138	240	291	329	337
65	Stephensburg	Eastview	69	53	57	64	66
66	Taylor Co. Junction	Taylor Co.	161	159	200	167	265
67	Tharp Jct.	Elizabethtown	69	103	124	137	151
68	Union City	Lake Reba Tap	138	240	306	371	412
69	West Garrard	West Garrard	345	1290	1504	1589	1669
LG&E/KU Total:				8392	9756	10987	11785
TVA							
70	Fox Hollow	East Glasgow Tap	161	267	298	387	406
71	McCreary Co.	Jellico	161	267	298	384	394
72	McCreary Co.	Wayne Co.	161	267	298	384	394
73	McCreary Co.	Winfield	161	574	638	710	763
74	Russell Co. Tap	Wolf Creek	161	267	298	387	406
75	Summer Shade	Summer Shade	161	267	298	387	406
76	Summer Shade Tap	Summer Shade	161	396	461	468	501
77	Wayne Co.	Wayne Co.	161	127	131	127	131
TVA Total:				2501	2798	3329	3501
Grand Total:				14499	16669	19229	20418

Table 6-2

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
A. New Transmission Lines	**Needed In-Service Date**
Construct a new Floyd-Woodstock 69kV line section using 556 ACSR (7 miles)	10/2023
Construct a new Coburg-EKPC Campbellsville 69kV line section using 556 ACSR (9.3 miles)	12/2026

Table 6-3

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
B. New Transmission Substations & Transmission Substation Upgrades **Project Description**	**Needed In-Service Date**
Rebuild the 69 kV Tyner Switching Station	10/2023
Build a new 69kV substation where the KU Bluegrass-Berea North line intersects Hickory Plains-Crooksville Tap	12/2035

Table 6-4

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022– 2036)	
C. New Transmission Switching Stations **Project Description**	**Needed In-Service Date**
Build a new Patriot Parkway 69kV (Switching Station	2/2022
Build a new Penn 69 kV Switching Station	12/2022
Build a new Norwood Junction 69kV Switching Station	11/2023
Build a new Coburg Junction 69kV Switching Station	12/2026

Table 6-5

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
D. Transmission Transformer Upgrades **Project Description**	**Needed In-Service Date**
Upgrade the existing West Berea 138-69 kV 100 MVA autotransformer to 150 MVA	11/2022

Table 6-6

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
E. Terminal Facility Upgrades & Additions **Project Description**	**Needed In-Service Date**
Add a new 69 kV breaker at Boone Switching for service to the Boone Distribution substation	10/2022
Add a new 138 kV breaker at Fawkes 138 kV for protection of the Fawkes-Fawkes KU interconnection	12/2022
Add a new 69 kV breaker at Elizabethtown	12/2022
Replace the relay at Argentum, and add a new 138 kV breaker for the existing line to Greenup Hydro	6/2023
Add a new breaker at Magoffin County for the existing 69 kV line to Falcon	12/2023
Add a new breaker at Rowan County for the existing 69 kV line to Elliotville	12/2026
Upgrade the CT associated with the Elizabethtown EK1-Elizabethtown EK2 69kV line section	12/2033

Table 6-7

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
F. Transmission Line Rebuilds **Project Description**	**Needed In-Service Date**
Rebuild the 4/0 Hodgenville - Magnolia 69kV line section using 556 ACSR (8.49 miles)	5/2022
Rebuild the 4/0 Boone-Bullittsville 69kV line section using 556 ACSR (6.4 miles)	5/2022
Rebuild the 4/0 Brodhead-Three Links Junction 69 kV line section using 556 ACSR (8.2 miles)	10/2022
Rebuild the 3/0 Goddard-Oak Ridge 69kV line section using 556 ACSR (8.04 miles)	6/2023
Rebuild the 3/0 Beattyville Distribution-Booneville 69kV line section using 556 ACSR (9 miles)	7/2023
Rebuild the 4/0 Three Links - Three Links Junction 69kV line section using 556 ACSR (9.3 miles)	8/2023
Rebuild the 4/0 Summersville - Magnolia 69kV line section using 556 ACSR (15 miles)	12/2023
Rebuild the 4/0 Boone-Williamstown 69 kV line section using 556 ACSR (28.5 miles)	12/2023
Rebuild the 3/0 Booneville-South Fork 69kV line section using 556 ACSR (5.48 miles)	5/2024
Rebuild the 3/0 Oak Ridge-Charters 69kV line section using 556 ACSR (8.95 miles)	9/2024
Rebuild the 3/0 Fall Rock-Manchester 69kV line section using 556 ACSR (5.83 miles)	12/2024
Rebuild the 3/0 Stephensburg-Vertrees 69kV line section using 556 ACSR (8.7 miles)	12/2024
Rebuild the 556 Duncannon Lane-Fawkes 69kV line section using 795 ACSR (7.48 miles)	12/2024
Rebuild the 4/0 KU Carrollton – EK Bedford 69kV line section using 556 ACSR (22.1 miles)	12/2025
Rebuild the 3/0 Liberty Junction-Peyton’s Store 69kV line section using 556 ACSR (14.2 miles)	6/2025
Rebuild the 4/0 Headquarters-Millersburg 69kV line section using 556 ACSR (5.12 miles)	12/2025

Rebuild the 4/0 Norwood Junction-Shopville 69kV line section using 556 ACSR (6.3 miles)	6/2026
Rebuild the 3/0 KU Wofford-McCreary Co. Junction 69kV line section using 556 ACSR (20.7 miles)	12/2027
Rebuild the 266.8 Budd-Logan Tap 69kV line section using 556 ACSR (0.48 miles)	6/2027
Rebuild the 3/0 Headquarters - Murphysville 69kV line section using 556 ACSR (19.9 miles)	7/2027
Rebuild the 4/0 Maytown - West Liberty 69kV line section using 556 ACSR (12.3 miles)	11/2028
Rebuild the 3/0 South Fork - Tyner 69kV line section using 556 ACSR (14.9 miles)	12/2028
Rebuild the 266.8 Dale-Newby 69 kV Double-Circuit line section using 556 ACSR (11.1 miles)	12/2028
Rebuild the 266.8 Bekaert-Budd 69kV line section using 556 ACSR (0.76 miles)	6/2030
Rebuild the 556 Tharp Tap-Elizabethtown KU 69kV line section using 954 ACSR (2.1 miles)	12/2034

Table 6-8

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
G. Transmission Line High Temperature Upgrades **Project Description**	**Needed In-Service Date**
Increase the conductor maximum operating temperature of the Laurel Co-North London 266 ACSR 69kV line section from 167°F to 212°F (3.12 miles)	6/2029
Increase the conductor maximum operating temperature of the Tharp Tap-KU Elizabethtown 69kV 556 ACSR line section from 280°F to 302°F (2.1 miles)	12/2030
Increase the conductor maximum operating temperature of the Plumville-Rectorville 266 ACSR 69kV line section from 167°F to 212°F (2.9 miles)	6/2031
Increase the conductor maximum operating temperature of the Elizabethtown EK2-Tharp Tap 69kV 556 ACSR line section from 212°F to 280°F (1.7 miles)	12/2033

Table 6-9

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
H. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Install a new 28 MVAR, 69 kV capacitor bank at Liberty Junction substation	12/2026
Increase the size of the Coburg 69kV Capacitor Bank from 7.1 to 17 MVARs	12/2026
Increase the size of the Green River Plaza 69kV Capacitor Bank from 20.4 to 27 MVARs	12/2026
Install a new 20.5 MVAR, 69 kV capacitor bank at Bullitt County substation	12/2031
Install a new 8.5 MVAR cap bank at Elliottville substation	12/2031

Table 6-10

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2022 – 2025)	
I. New Distribution Substations and associated Tap Lines Project Description	**Needed In-Service Date**
Construct a new Speedwell Road 69-25 kV 18/24/30 MVA Distribution Substation and associated 69 kV tap line to Crooksville (4.79 miles)	4/2022
Construct a new Dahl Rd 69-12.5 kV 12/16/20 MVA Distribution Substation, tapping the existing Asahi Motor Wheel-Shopville 69kV line section (0.1 miles)	6/2022
Construct a new Mineola Pike 69-12.5 kV 12/16/20 MVA Distribution Substation and associated 69 kV tap line to the Hebron 69 kV substation (8 miles)	12/2024
Construct a new Wieland 69-25 kV 18/24/30 MVA Distribution Substation by looping it into the existing Bekaert-Budd 69 kV line section (1.2 miles)	12/2025

Table 6-11

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2022 – 2025)	
J. Distribution Substation Upgrades Project Description	**Needed In-Service Date**
Rebuild the 69 kV Miller's Creek Distribution Substation to 161-13.2 kV 12/16/20 MVA, tapping the Powell County-Beattyville 161 kV line (New Location) (0.6 miles)	4/2022
Rebuild and upgrade the Lees Lick 69-12.47 kV Distribution Substation to 12/16/20 MVA	5/2022
Rebuild the East Bernstadt Distribution Substation to 69-13.2kV 12/16/20 MVA	5/2022
Rebuild and upgrade the Thelma Distribution Substation to 69-13.2 kV 12/16/20 MVA	6/2022
Rebuild and upgrade the existing Highland 69-25 kV Distribution Substation and tap to 12/16/20 MVA (New Location) (0.3 miles)	9/2022
Rebuild and upgrade the Balltown Distribution Substation to 69-13.2kV 12/16/20 MVA	9/2022
Rebuild and upgrade the Munk 69-12.47 kV Distribution Substation	11/2022
Rebuild and upgrade the Redbush Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2022
Rebuild and upgrade the Penn Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2022
Rebuild and upgrade the Newfoundland 69kV Distribution Substation to 69-13.2kV 12/16/20	1/2023
Rebuild and upgrade the Rice Distribution Substation to 69-13.2 kV 12/16/20 MVA	1/2023
Rebuild the Griffin 69 kV Distribution Substation and tap line (6.4 miles)	6/2023
Rebuild and upgrade the Rockholds Distribution Substation to 69-13.2 kV 12/16/20 MVA	7/2023

Rebuild the Frenchburg Distribution Substation to 69kV-25kV 11.2 MVA	7/2023
White Oak 69-13.2 kV 12/16/20 MVA Distribution Substation & Tap and Retirement of the South Fork Distribution Substation (New Location) (0.1 miles)	8/2023
Rebuild and upgrade the Three Links Distribution Station to 69/13.2kV 12/16/20	8/2023
Rebuild and upgrade the Albany Distribution Substation to 69-13.2 12/16/20 MVA	9/2023
Rebuild the Shopville 69kV Distribution Substation to 69-13.2kV	10/2023
Rebuild the 69 kV Taylorsville Distribution Substation to 161-13.2kV (New Location) (0.2 miles)	11/2023
Rebuild and relocate the Tyner 69 kV Distribution Substation in the Tyner 161 kV yard (0.1 miles)	11/2023
Rebuild and upgrade the Brodhead Substation to 69-13.2kV 12/16/20 MVA	11/2023
Rebuild and upgrade the Oakdale Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2023
Upgrade the 3M #1 Transformer to 15/20/25 MVA	12/2023
Rebuild and upgrade the Nicholasville Substation to 69-13.2kV 12/16/20 MVA	3/2024
Rebuild and upgrade the Salt Lick Distribution Substation to 138-13.2 kV 12/16/20 MVA	9/2024
Rebuild and upgrade the Newby Substation to 69-12.5kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Campbellsburg Distribution Substation 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Greensburg Distribution Substation 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the North Springfield Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Elizabethtown #1 Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Whitley City Distribution Substation to 69-26.4 kV 12/16/20 MVA	12/2024
Rebuild the Homestead Lane Distribution Substation to 69-13.2 kV 18/24/30 MVA	12/2025

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

Existing Generation

Maintenance management for existing generation assets is vital to keep them operating reliably, productively, efficiently, and cost effectively. EKPC has developed a long-range plan to satisfy maintenance needs for each of its existing generating units, which is discussed in the following subsection. Please also see the discussion in Section 1.6, Power Supply Actions, in the Executive Summary of this IRP.

Maintenance of Existing EKPC Generating Units

Current facilities were brought online at Cooper Power Station in 1965-69, and Spurlock Power Station in 1977-81 for Units 1 and 2, the Gilbert Unit in 2005, and Unit 4 in 2009. J.K. Smith Station combustion turbines were placed in operation in 1999, 2001, 2005, and 2010. Bluegrass Station, with three combustion turbine units that started operating in 2002, was purchased by EKPC on December 29, 2015. Each of EKPC's generating plants was state-of-the-art at the time of their construction and designed to operate under conditions and regulations existing at that time. The continued reliable operation of these plants requires both normal maintenance and systematic review of changing conditions.

EKPC has a formal maintenance planning process that seeks to identify needed major projects on a five-year horizon. A plan for maintenance is continuously developed following the review of numerous plant subsystems, assimilation of operational data, and review of past operating history. Through proper planning and implementation, EKPC effectively manages operations, while meeting environmental compliance regulations, to provide reliable, economical electric service to its owner-members and their retail members.

Methodology for Five-Year Major Projects Plan

The areas addressed in the development of the current plan include safety, generating plant performance, operation, maintenance, and regulatory compliance. On an annual cycle, the prior plan is reviewed and evaluated by plant operations staff, engineers, and environmental experts, to develop the newest plan. Each individual major project scheduled in the plan is further developed, reviewed and justified prior to requesting approval from the EKPC Board of Directors for implementation of the project. Prior to requesting this approval, an analysis is conducted that takes into account costs, timing, risks, and benefits of the project to ensure that completion of the proposed project is the best decision for EKPC. Justifications are developed based on the economic analysis, risk, and other benefits such as safety or regulatory requirements. Depending on the cost of the project, the economic analysis results and justification are then presented to the Board along with a request to approve the project. Smaller projects follow the same basic path, but go through EKPC's internal review and approval process but do not require board approval.

Current Five-Year Major Projects Study

This plan covers the period from 2022 through 2026. Table 7-1 through Table 7-5 list the major projects planned for each plant during the five-year period.

Table 7-1
($100,000 and Above)
Bluegrass Station

Description	Operating Unit	Date
Generator Inspections	OC01-03	2022
Relocate GSU Protection Panel	OC00	2022
Enclosure Doors	OC00	2023
Demin Tank- Strip and Re-coat interior	OC00	2023
Stack Repair	OC01-02	2023
OC00 - Common		
OC01 - Bluegrass 1		
OC02 - Bluegrass 2		
OC03 - Bluegrass 3		

Table 7-2
($100,000 and Above)
Cooper Power Station

Description	Operating Unit	Date
Temporary Landfill Cap	CP00	2022
ABB Symphony Plus Operations Rev. Upg	CP01	2022
ABB Symphony Plus Operations Rev. Upg	CP02	2022
U2 AQCS FD Fan Hub Swap	CP02	2022
U1 Boiler Economizer Tubes Installation	CP01	2023
Boiler Economizer Tubes Matl Purchase	CP01	2023
U1 Boiler Weld Overlay In Firebox	CP01	2023
1A Hyd Turb Rebuild	CP01	2023
Turbine Valve Rebuild	CP01	2025
High Energy Piping Assessment	CP01	2025
PJFF Bag Replacement	CP02	2025
Boiler Assessment	CP01	2026
C.W.P. And Motor Rebuild A	CP01	2026
CP00 - Common		
CP01 - Cooper 1		
CP02 - Cooper 2		

Table 7-3
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Resurface Existing Blacktop	SP00	2022
Painting Structural Steel - Select Areas	SP00	2022
Ash Haul Bridge Repairs	SP00	2022
Add Concrete Pad At Rock Pile	SP00	2022
Clean & Inspect River Intake	SP00	2022
Clean , Test & Repair Well Pumps	SP00	2022
Water Services Building Piping Replacement	SP00	2022
Clean & Inspect River Intake	SP00	2022
Boiler Ignition Fuel Oil Tank Repairs	SP00	2022
Overhaul (4) Pulverizers	SP01	2022
Outage Boiler & Air heater Repair	SP01	2022
Outage Boiler & Air heater Inspection	SP01	2022
High Energy Piping Assessment	SP01	2022
Air Heater Wash (2)	SP01	2022
Refractory Repairs Boiler	SP01	2022
Expansion Joint Repairs	SP01	2022
1A BFP 5Yr Overhaul	SP01	2022
BFW-Medium Piping Assessment	SP01	2022
Tube Alignment Castings	SP01	2022
ID Fan Outlet Duct SS Overlay	SP01	2022
ID Fan Outlet Duct Expansion Joints D6-A & D6-B Replacement	SP01	2022
Sootblowing Air Receiver Tank 5 Year Inspection (Scafffold,Insulation,Nde,Painting)	SP01	2022
DA Tank Internal Repairs And Shell NDE	SP01	2022
HMI Operators S+ Upgrade - Comp/Software/Graphics	SP01	2022
Outage Boiler & Air heater Inspection And Repair	SP02	2022
Boiler Deslags-2	SP02	2022
Air Heater Wash 2 (TR)	SP02	2022
High Energy Piping Assessments	SP02	2022
Replace 2A BWCP Heat Exchanger	SP02	2022
Pulverizer Overhauls	SP02	2022
Rebuild Pulverizer Journals (3)	SP02	2022
Expansion Joint Repairs	SP02	2022
FD Fan Rotor Replacement	SP02	2022

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
2B FD Fan Rotor Rebuild	SP02	2022
BFP Rotating Element Rebuild	SP02	2022
ID Fan Rebuild	SP02	2022
Condensate Pump Rebuild	SP02	2022
BFP Rebuild	SP02	2022
Lower Waterwall Remediation	SP02	2022
BFW-Medium Piping Assessment	SP02	2022
RH Leading Edge Replacement	SP02	2022
Amstar Flame Spray Repairs	SP03	2022
Boiler & Air heater Inspection	SP03	2022
Boiler & Air heater Repairs	SP03	2022
13.8 Switchgear Block I/O Replacement	SP03	2022
Plenum Expansion Joint Repairs	SP03	2022
SRD Constant Support Hanger Replacement	SP03	2022
Power Roof Exhauster Complete Replacement	SP04	2022
Amstar Flame Spray Repairs	SP04	2022
Boiler & Air heater Repairs	SP04	2022
4A Voith Drive Rebuild 5 Yr PM	SP04	2022
Plenum Expansion Joint Repairs	SP04	2022
Rebuild Limestone Mill Journals	SP03	2022
Refractory	SP03	2022
Rebuild Limestone Mill Journals	SP04	2022
Refractory (MP)	SP04	2022
SH & RH Floors	SP04	2022
SH & RH Walls	SP04	2022
Outage- Precipitator Inspection And Repairs	SP01	2022
Outage- Precipitator Inspection And Repairs	SP02	2022
Tube Sheet Modules / Wall Repair	SP03	2022
Replace Baghouse Bags/Filters	SP04	2022
Replace The Cone Liners In The UC4 Surge Bin	SP04	2022
Install Actuators On Coal Slide Inlet Chute Isolation Valves	SP01	2022
Overhaul U3 Crushers	SP03	2022
Replace The Chain And Sprockets On SR#3	SP03	2022

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Replace The Rotor In U3 Crusher	SP03	2022
Install Dust Suppression On PC3 And BC3 Conveyors	SP03	2022
Overhaul U4 Crushers	SP04	2022
Install Dust Suppression on PC4 and BC4 Conveyors	SP04	2022
SCR Catalyst Replacement	SP01	2022
SCR Inlet Expansion Joint D10-F Replacement	SP01	2022
Lagoon / Coal Pile Runoff Cleaning	SP00	2022
Reagent Line Replacement	SP20	2022
Filter Feed Line	SP20	2022
Scrubber Inlet Duct Repairs	SP21	2022
WESP SIRS Clean/Inspect/Repair	SP21	2022
Replace Kirk Keys	SP21	2022
WESP - Collecting Plate Replacement	SP21	2022
WESP SIRS Clean/Inspect/Repair	SP22	2022
2A Vacuum Pump - Refurbishment	SP22	2022
WESP - Collecting Plate Replacement	SP22	2022
FWH7 Extraction Steam NRV Relocation/Replacement	SP01	2022
Extraction Steam Secondary NRV Inspection	SP01	2022
Unit 1 MCC Essential 1A and 1B	SP01	2022
Asbestos Abatement for Condenser Water Boxes/Piping	SP01	2022
Turbine Valves	SP02	2022
Circ water line repair	SP02	2022
Bottle Replacement for Switchgear	SP02	2022
Cooling Tower Inspection & Repair	SP03	2022
Unit 3 Cooling Tower Fill Replacement - 3 cells	SP03	2022
Turbine and Exciter Controls	SP03	2022
Cooling Tower Inspection & Repair	SP04	2022
Cooling Tower Rain Zone Repair	SP04	2022
Turbine and Exciter Controls	SP04	2022
Spurlock 1 / 2 Bottom Ash Silo Elevator	SP01/02	2022
Air Heater Wash Water Pumping System	SP00	2022
Ash Pond Closure - CCR / ELG Compliance	SP00	2022

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
CCR/ELG Compliance WMB Pond	SP00	2022
Ignition Fuel Oil Pipe Replacement	SP00	2022
Landfill - Area D Phase 2 Construction	SP00	2022
Landfill - Area D Phase 1 Construction	SP00	2022
Landfill Area D Construction - Ponds and Stream Mitigation	SP00	2022
SSR-2 Compressor Replacement	SP00	2022
Unit 1 Blowdown Flash Tank	SP01	2022
Unit 1 Condenser Retube	SP01	2022
Unit 1 Superheat Outlet Replacement	SP01	2022
Unit 2 Cooling Tower Replacement Project	SP02	2022
Unit 3 Blowdown Flash Tank	SP03	2022
Unit 3 Boiler Turn-Down Modifications	SP03	2022
Unit 4 Blowdown Flash Tank	SP04	2022
WWT and Ash System Platforms and Foggers	SP00	2022
Well 2R	SP00	2022
Resurface Existing Blacktop	SP00	2023
Chiller Replacement - 3rd of 3	SP00	2023
Day/Night Lighting Control	SP00	2023
Structural Painting	SP00	2023
Ash Haul Bridge Repairs	SP00	2023
Clean & Inspect River Intake	SP00	2023
Clean , Test & Repair Well Pumps	SP00	2023
Water Services Building Piping Replacement	SP00	2023
PLC to DCS RO and Pretreatment	SP00	2023
Transfer Tower 2 & 3 Controller Replacement	SP00	2023
4A IAC Overhaul	SP04	2023
4B IAC Overhaul	SP04	2023
Boiler Ignition Fuel Oil Tank Repairs	SP00	2023
Overhaul (4) Pulverizers	SP01	2023
Outage Boiler & Air heater Repair	SP01	2023
Outage Boiler & Air heater Inspection	SP01	2023
High Energy Piping Assessment	SP01	2023
Air Heater Wash (2)	SP01	2023

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Boiler Chemical Clean	SP01	2023
Expansion Joint Repairs	SP01	2023
Condensate Pump 1B Rebuild	SP01	2023
BFW-Medium Piping Assessment	SP01	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics - Finalize	SP01	2023
Pulverizer Maintenance	SP02	2023
Outage Boiler & Air heater Inspection and Repair	SP02	2023
Misc. Scaffolding Boiler	SP02	2023
Boiler Deslags-2	SP02	2023
Air Heater Wash 2 (TR)	SP02	2023
FD Fan Rotor Rebuild	SP02	2023
High Energy Piping Assessments	SP02	2023
Pulverizer Overhauls	SP02	2023
Rebuild Pulverizer Journals (6)	SP02	2023
Boiler Chemical Clean	SP02	2023
Expansion Joint Repairs	SP02	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics - Finalize	SP02	2023
U2 Pulverizer Inching Drive	SP02	2023
GECKO UT Inspection of Boiler Tubing	SP02	2023
2A ID Fan - Hydraulic Unit and Feedback Changeout	SP02	2023
ID Fan Stall Protection System	SP02	2023
Amstar Flame Spray Repairs	SP03	2023
Robotic Ut Inspection	SP03	2023
Boiler & Air heater Inspection	SP03	2023
Boiler & Air heater Repairs	SP03	2023
Boiler Chemical Clean	SP03	2023
3A FP volute replacement (2014 last)	SP03	2023
NO. 1 Sector Plate Replacement (Hot PA to GAS)	SP03	2023
Buy & install new condensate pump then rebuild for spare	SP03	2023
Air Preheater Sensorless Leakage Control System Upgrade (SLCS)	SP03	2023
CCW Heat Exchanger 5 yr PM	SP04	2023
Amstar Flame Spray Repairs	SP04	2023
Robotic Ut Inspection	SP04	2023
Boiler & Air heater Inspection	SP04	2023
Boiler & Air heater Repairs	SP04	2023
Air Preheater Sensorless Leakage Control System Upgrade (SLCS)	SP04	2023
Rebuild Limestone Mill Journals	SP03	2023
Refractory	SP03	2023

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Rebuild Limestone Mill Journals	SP04	2023
Refractory (MP)	SP04	2023
Outage- Precipitator Inspection And Repairs	SP01	2023
Outage- Precipitator Inspection And Repairs	SP02	2023
Tube Sheet Modules / Wall Repair	SP03	2023
Baghouse bag/filter membrane replacement	SP03	2023
Inspect & Repair Cells	SP00	2023
Dredge River around Unloading Cells	SP00	2023
Inspect & Repair Cells	SP00	2023
Dredge River around Unloading Cells	SP00	2023
Paint Barge Unloader	SP00	2023
Paint CH Structural Steel	SP00	2023
Overhaul U3 Crushers	SP03	2023
Overhaul U4 Crushers	SP04	2023
#3 Dozer Powertrain Rebuild	SP00	2023
Ammonia Tuning Grid Pipe Replacement	SP02	2023
Lagoon / Coal Pile Runoff Cleaning	SP00	2023
WMB Pond Dredging	SP00	2023
Replace Horizontal Run of NUVALY Piping	SP01	2023
Replace Horizontal Run of NUVALY Piping	SP02	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics	SP20	2023
Scrubber Inlet Duct Repairs	SP21	2023
WESP SIRS Clean/Inspect/Repair	SP21	2023
WESP SIRS Clean/Inspect/Repair	SP22	2023
Brine Concentrator Tube cleaning	SP20	2023
Chemical Clean Evaporator Heat Exchanger	SP20	2023
Replace Filter Press Cloths	SP20	2023
Insulation/Heat Trace	SP20	2023
Electrical Instrumentation	SP20	2023
DSI Building Electrical Upgrade	SP21	2023
DSI Building Electrical Upgrade	SP22	2023
MCC Essential Service Upgrade	SP01	2023
Unit 1 Generator Relay Panel Replacement	SP01	2023
Stator Leak Monitoring System Replacement	SP02	2023
Cooling Tower Inspection & Repair	SP03	2023
Turbine valve repairs	SP03	2023
CT Lilly Pads	SP03	2023

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Unit 3 Cooling Tower Fill Replacement	SP03	2023
Cooling Tower Inspection & Repair	SP04	2023
Cooling Tower Rain Zone Repair	SP04	2023
CCR/ELG Compliance WMB Pond	SP00	2023
Ignition Fuel Oil Pipe Replacement	SP00	2023
Landfill - Area D Phase 2 Construction	SP00	2023
Unit 1 Condenser Retube	SP01	2023
Unit 1 Superheat Outlet Replacement	SP01	2023
Unit 3 Boiler Turn-Down Modifications	SP03	2023
Boiler Assessment	SP01	2024
"B" Feed Pump 5yr PM	SP01	2024
Boiler Assessment	SP02	2024
"B" Feed Pump 5yr PM	SP02	2024
FD Fan Overhaul A	SP02	2024
Boiler Assessment	SP03	2024
"B" Feed Pump 9yr PM	SP03	2024
"B" Voith Drive 5yr PM	SP03	2024
Limestone Mill 3-4yr PM	SP03	2024
Boiler Assessment	SP04	2024
Turbine Valves 5yr PM	SP04	2024
Baghouse filter replacement 2yr PM	SP04	2024
Ash Pond Closure - CCR / ELG Compliance	SP00	2024
Boiler Assessment	SP01	2025
"A" Feed Pump 5yr PM	SP01	2025
Boiler Assessment	SP02	2025
"A" Feed Pump 5yr PM	SP02	2025
ID Fan Overhaul B	SP02	2025
Boiler Assessment	SP03	2025
Major Turbine 10yr PM	SP03	2025
Generator Field & Stator	SP03	2025
Baghouse filter replacement 2yr PM	SP03	2025
Boiler Assessment	SP04	2025
Ash Pond Closure - CCR / ELG Compliance	SP00	2025
Boiler Assessment	SP01	2026
C.W.P. and Motor Rebuild A	SP01	2026

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Boiler Assessment	SP02	2026
C.W.P. and Motor Rebuild A	SP02	2026
ID Fan Overhaul A	SP02	2026
Boiler Assessment	SP03	2026
Boiler Assessment	SP04	2026
"A" Voith Drive 5yr PM	SP04	2026
Limestone Mill 3-4yr PM	SP04	2026
Baghouse filter replacement 2yr PM	SP04	2026
SP00 – Common		
SP01 - Spurlock 1		
SP02 - Spurlock 2		
SP03 – Spurlock 3		
SP04 - Spurlock 4		
SP20 – Spurlock Scrubber Common		
SP21 - Spurlock Scrubber Unit 1		
SP22 - Spurlock Scrubber Unit 2		

Table 7-4
Smith CTs - Station

Description	Operating Unit	Date
Structure Painting- Units 2 and 4 and bay	SM52/54	2022
Structure Painting- Units 1 and 3	SM51/53	2022
Site Blacktop repair	SM50	2022
U1-3 Camera replacement	SM51-53	2022
Rebuild liquid fuel pump- #1 (Unit 2)	SM52	2022
15 Yr Breaker Maintenance Units 1 & 3	SM51/53	2022
Retrofit ABB AdVac Breakers	SM50	2022
Unit No. 6 CI	SM56	2022
Unit No. 6 Parts Refurbishment	SM56	2022
Unit No. 7 CI Inspection	SM57	2022
Unit 10 Row 3-5 HPC Blade	SM60	2022
Gas Line Inspection from Bybee to Plant	SM50	2022
Intake Fan PLC Replacements on U1, 2, & 3	SM51-53	2022
Unit 1 Exhaust Repairs	SM51	2022
Waterwash CO or NOX	SM50	2022
Restack catalyst for LMS	SM50	2022
J.K. Smith Electrical Infrastructure Upgrades	SM50	2022
Smith New Water Intake	SM50	2022
Rebuild liquid fuel pump- #1 (Unit 1)	SM51	2023
Gas Compressor Overhaul	SM50	2023
Gas Compressor Overhaul	SM50	2023
Retrofit 5000A 13.8 KV Generator Breakers 4-7	SM54-57	2023
Unit No. 7 Parts Refurbishment	SM57	2023
Waterwash CO or NOX	SM50	2023
Restack catalyst for LMS	SM50	2023
Smith New Demineralized Water Storage Tank	SM50	2023
Smith New Water Intake	SM50	2023

Table 7-4 (continued)
Smith CTs - Station

Description	Operating Unit	Date
Generator Ckt Bkr 12 yr Maintenance	SM60	2024
Catalyst Replace	SM60	2025
SM50 - Smith Units Common		
SM51 - Smith Unit 1		
SM52 - Smith Unit 2		
SM53 - Smith Unit 3		
SM54 - Smith Unit 4		
SM55 - Smith Unit 5		
SM56 - Smith Unit 6		
SM57 - Smith Unit 7		
SM59 - Smith Unit 9		
SM60 - Smith Unit 10		

Table 7-5
Landfill Gas

Description	Operating Unit	Date
Green Valley- Major Overhaul- Unit 2	LF01	2022
Laurel Ridge- Fuel skid upgrade	LF02	2022
Laurel Ridge - Major Overhaul- Unit 1	LF02	2022
Bavarian- Major Overhaul- Unit 4	LF03	2022
Pendleton- Major Overhaul- Unit 3	LF05	2022
Glasgow- Major Overhaul- Unit 1	LF07	2022
Green Valley- Major Overhaul- Unit 2 & 3	LF01	2023
Bavarian- Major Overhaul- Unit 1 & 3	LF03	2023
Hardin- Major Overhaul- Unit 2	LF04	2023
Pendleton- Major Overhaul- Unit 1 & 4	LF05	2023
Laurel Ridge - Major Overhaul- Unit 4	LF02	2024
Hardin- Major Overhaul- Unit 3	LF04	2024
Laurel Ridge - Major Overhaul- Unit 2	LF02	2025
Bavarian- Major Overhaul- Unit 2	LF03	2025
Laurel Ridge - Major Overhaul- Unit 3	LF02	2026
Pendleton- Major Overhaul- Unit 4	LF05	2026

SECTION 8.0

INTEGRATED RESOURCE PLANNING

SECTION 8.0

INTEGRATED RESOURCE PLANNING

The following filing requirements are addressed in this section.

807 KAR 5:058 Section 5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

807 KAR 5:058 Section 8(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

807 KAR 5:058 Section 8.(2)(c) The utility shall describe and discuss all options considered for inclusion in the plan including: (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units.

807 KAR 5:058 Section 8.(2)(d) The utility shall describe and discuss all options considered for inclusion in the plan including: (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

807 KAR 5:058 Section 8(3)(c) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8(3)(d) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8.(4)(a) 1-5 and 7-11 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak: 1. Forecast peak load; 2. Capacity from existing resources before consideration of retirements; 3. Capacity from planned utility-owned generating plant capacity additions; 4. Capacity available from firm purchases from other utilities; 5. Capacity available from firm purchases from nonutility sources of generation; 7. Committed capacity sales to wholesale customers coincident with peak; 8. Planned retirements; 9. Reserve requirements; 10. Capacity excess or deficit; 11. Capacity or reserve margin.

807 KAR 5:058 Section 8(4)(a)(6) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak. (6) On planned annual generation: Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(b) 1-4 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (b) On planned annual generation: (1) Total forecast firm energy requirements; (2) Energy from existing and planned utility generating resources disaggregated by primary fuel type; (3) Energy from firm purchases from other utilities; (4) Energy from firm purchases from nonutility sources of generation.

807 KAR 5:058 Section 8(4)(b)(5) On planned annual generation: 5. Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(c) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

807 KAR 5:058 Section 8.(5)(a) The resource assessment and acquisition plan shall include a description and discussion of: (a) General methodological approach, models, data sets, and information used by the company.

807 KAR 5:058 Section 8(5)(b) The resource assessment and acquisition plan shall include a description and discussion of: (b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses.

807 KAR 5:058 Section 8.(5)(d) The resource assessment and acquisition plan shall include a description and discussion of: (d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options.

807 KAR 5:058 Section 8(5)(g) The resource assessment and acquisition plan shall include a description and discussion of: (g) Consideration given by the utility to market forces and competition in the development of the plan.

8.1 Introduction

EKPC's mission is to serve its member-owned cooperatives by safely delivering reliable, affordable and sustainable energy and related services. One of its strategic objectives is to actively manage EKPC's current and future asset portfolio to deliver reliable, affordable and sustainable energy from appropriately diversified sources, and work with federal and state stakeholders to ensure high reliability and economic viability while mitigating evolving regulatory challenges including possible carbon emissions reduction mandates and penalties. To meet this strategic objective, EKPC will actively manage its current and future asset portfolio to maintain high reliability of electric service to its owner-members and economically diversify its energy resources, including market purchases, fossil fuels, renewables storage, demand management and energy efficiency programs, and partnering opportunities. In light of the growing risks related to changes to existing and new environmental rules, including future regulation of greenhouse gas emissions, EKPC will actively work with other electric utilities, businesses and industry, regulators and lawmakers to manage EKPC's compliance strategies while minimizing costs to our owner-members.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis, as well as a cash flow basis. Any major power supply acquisition will be made via a Request for Proposals process ("RFP"). The RFP process ensures that EKPC has adequately surveyed available resources in the market for delivery to serve the EKPC load in a reliable, affordable and sustainable manner.

8.2 Resource Planning Methodology Overview

EKPC develops a detailed load forecast every two years, with the most recent being completed in 2020. This forecast was approved by the EKPC Board of Directors in December, 2020, and was approved by the Rural Utilities Service ("RUS"). The load forecast was updated to reflect known conditions in 2020 and that data has been used in this IRP analysis.

Market and fuel prices are updated on a regular basis to ensure that current expectations are being modeled in the analysis. Fuel and market cost assumptions and projections were developed in the Fall 2021 in order to have adequate time to robustly evaluate integrated resource plan alternatives. These assumptions appear to be low in the near term as compared to prices and projections in March 2022. EKPC continually monitors its planning assumptions and will adjust its plans as needed. Based on this input data, then the DSM alternatives are evaluated utilizing the standard California tests. Based on those results, the load is modified to reflect the DSM analyses prior to developing the capacity expansion plan. Additionally, EKPC conducted an environmental assessment of its existing units and determined no additional substantial unit modifications were required to meet current or predicted regulations.

8.3 Load Requirements to be Served

The forecast indicates that for the period 2022 through 2036, total energy requirements will increase by an average of 1.1 percent per year. Winter and summer net peak demand will increase by 0.6 percent and 0.8 percent, respectively.

Table 8-1
Load Impacts of DSM Programs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	-7,508	-2.0	-3.3
2023	-15,016	-4.1	-6.6
2024	-22,523	-6.1	-9.8
2025	-30,031	-8.2	-13.1
2026	-37,539	-10.2	-16.4
2027	-44,800	-12.2	-19.6
2028	-52,061	-14.2	-22.8
2029	-59,323	-16.2	-26.1
2030	-66,584	-18.1	-29.3
2031	-73,845	-20.1	-32.5
2032	-81,106	-22.1	-35.7
2033	-88,368	-24.0	-38.9
2034	-95,629	-26.0	-42.2
2035	-102,890	-28.0	-45.4
2036	-110,151	-29.9	-48.6

8.4 Supply Side Optimization and Modeling

The primary model used in developing the resource plan was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost model calculates the hour-by-hour operation of the generation system including, unit hourly generation and commitment and power purchases and sales, including economy and day ahead transactions in the PJM energy market, and daily and monthly options. Generating unit input includes expected outages, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.

For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast. Around this forecasted load, a range of distributions created four additional loads to define the high and low range of the potential loads to be examined. The model draws load data a few days at a time from the different forecasts (to represent weather patterns) to assemble the hourly loads to be simulated. Each iteration of the model draws a new load forecast to simulate. Actual and forecasted market prices, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations.

RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates. The annualized fixed costs for capital are included along with the variable costs associated with a particular resource. Resources considered included:

Traditional Resources

Table 8-2

Resource	Capacity Type	Capacity (MW)	Primary Fuel	Projected Capital Cost (2020$) * $/kW	$M
LMS100 CT	Peaking	100	Natural Gas	[redacted]	
7F SCGT	Peaking	225	Natural Gas		
Combined Cycle	Peaking/Intermediate	418	Natural Gas		
Solar	Intermittent	150	Solar		
Solar	Power Purchase	100	Solar		
PPA - Winter Seasonal Market	Power Purchase	100	n/a		

* Capital Costs Source: National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") 2021
Capital Costs Source: Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2021
Market Cost Source: NRCO Power Marketing Forecast, November 2021

Renewable and Partnering Opportunities

EKPC is a member of the National Renewables Cooperative Organization ("NRCO"). NRCO offers cooperatives access to the necessary resources to thoroughly evaluate renewable energy projects without the expense of a dedicated staff. NRCO is active in the renewable energy marketplace on behalf of its members and customers, providing a centralized source of intelligence and opportunities. NRCO evaluates projects, presenting only the most promising to its members. NRCO facilitates transmission constraint modeling, Renewable Energy Credit market analysis, and engineering studies, and packages these into comprehensive recommendations. NRCO offers an established subscription process to participate in specific projects and can help members and customers with the ongoing operations and maintenance of those projects. By aggregating demand amongst multiple power supply cooperatives, NRCO offers developers a venue for efficiently reaching a larger and more diverse set of buyers. To date, EKPC has participated in the evaluation of out-of-state wind projects but has not found any that fit its generation expansion needs. NRCO assisted with the RFP, contract, and installation of the Cooperative Solar Farm One. The RFP solicitation, receiving responses, initial rankings, initial contract review, and installation monitoring were performed by NRCO.

The Kentucky River lock and dam system is located throughout the EKPC/Member Cooperative service territory. A member system is pursuing hydro-generation facilities via a power purchase agreement with a local developer. One facility rated at 2.64 MW was completed in 2021 and a similar second facility rated 3.04 MW is projected to be online in 2022.

EKPC currently has six landfill gas-to-energy ("LFGTE") facilities and continues to strive to improve performance at each of these facilities. 2021 generation from the existing EKPC facilities was approximately 99,977 MWh down from 101,207 MWh in 2017 and 90,220 MWh in 2016. EKPC developed the City of Glasgow Landfill into a LFGTE project, and it went online in December 2015.

In 2021 EKPC purchased 1,357 MWh from its one contracted cogeneration facility. Prominent barriers to new combined heat and power projects include large capital investment which many companies are not ready to make. These large investments require payback periods that may be long by their standards and these types of projects may not be directly related to the companies' main area of business. Two additional facilities recently received contractual approval for solar facilities. These solar installations total 425kWac of capacity. Small scale solar has a continuing interest and EKPC routinely answers questions regarding cogeneration/small power producer options.

EKPC, along with its sixteen owner-member cooperatives, implemented a community solar project in order to offer renewable solar energy to end users within the owner-member cooperative's service territories. This project is a result of the Demand-Side and Renewable Energy Collaborative group's efforts. The 8.5MWac facility began operations in November 2017. Marketing of the 25-year licenses continues under the Cooperative Solar program, which offers benefits of solar generation without the installation and maintenance requirements that would be necessary in a smaller home or office installation. This facility produced 13,204 MWh in 2021.

There are currently approximately 9,023 kW of solar voltaic installations within the EKPC service territory taking advantage of the member cooperatives' net metering tariff. This number continues to grow as solar voltaic prices continue to decrease. There also are approximately 24 kV of small wind turbine installations taking advantage of owner-member cooperative's net metering tariff.

Recently, several industrial end-use members contacted their respective distribution cooperative about securing renewable energy resources or Renewable Energy Certificates ("RECs"). Those industrial end-use members indicated they have a corporate interest in acquiring RECs through their cooperative.

EKPC, in concert with its owner-member cooperatives, developed programs and resulting tariffs to support those efforts. The Renewable Energy Program tariff was expanded to include two (2) new renewable energy options targeted to the commercial and industrial ("C&I") end-use members:

- Option B – Long-term Renewable Resources
- Option C – C&I RECs

The goal of the new program is to offer C&I end-use members' renewable resources and/or RECs to achieve their sustainability goals without cross-subsidization from or to non-participants. The Commission approved both Option B and Option C of the Renewable Energy Program tariff.

EKPC and its owner-member cooperatives have discussed the program with several large C&I end-use members. To date, one has already agreed to participate in the long-term renewable energy program. EKPC is working to secure the renewable resource as defined in the agreement. Another large C&I end-use member has agreed to a REC-only purchase. That business is offsetting 10% of its monthly consumption through RECs.

Table 8-3
EKPC Projected Additions and Reserves
(MW)

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserve Requirements[11]		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,434	3,136	0	75	4%	25%
2023	110					3,434	3,198	0	77	2%	22%
2024	200					3,434	3,318	0	78	2%	20%
2025						3,434	3,318	0	78	2%	20%
2026	200					3,534	3,438	0	79	1%	19%
2027	200					3,534	3,558	0	79	1%	19%
2028						3,534	3,558	0	80	0%	18%
2029						3,534	3,558	0	80	0%	17%
2030						3,534	3,558	0	80	0%	17%
2031	200					3,534	3,678	0	81	0%	16%
2032[12]	200			225	170	3,659	3,968	0	81	5%	22%
2033						3,659	3,968	0	82	5%	21%
2034						3,659	3,968	0	82	4%	20%
2035						3,659	3,968	0	83	4%	19%
2036						3,659	3,968	0	83	3%	19%

A minimum and maximum amount of capacity to be added by the model is specified to correspond to a specified reserve margin. The Resource Optimizer can simulate thousands of combinations of potential resources to determine the lowest cost plans. The new resources have to be simulated in operation with the current resources to determine the optimum expansion for the system. The lowest cost plans are determined from the present value of total production cost and annual fixed costs of future alternatives.

[11] Based on PJM reserve requirements
[12] Only generation added for the purpose of covering summer peak load capacity obligations is considered "capacity" additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply "capacity" to its portfolio or the PJM system.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 2500 unique expansion plans, with each of those simulated with 5 iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2022 through 2036. The results in the following table, Table 8.4, show the five lowest cost plans out of 2,500 plans simulated.

Table 8-4
DSM AFFECTED BASE RESOURCE OPTIMIZATION
Total tries: 2,500
Top Cases with specific resource and in-service date

Case 1	
Seasonal Purchase	1-1-2024
Peaking Resource	1-1-2032
Case 2	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2035
Peaking Resource	1-1-2033
Intermittent Resource	1-1-2029
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2033
Case 3	
Seasonal Purchase	1- 1-2022
Peaking Resource	1- 1-2034
Intermittent Resource	1-1-2035
Case 4	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2033
Peaking Resource	1-1-2032
Peaking Resource	1-1-2036
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2033
Case 5	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2024
Peaking Resource	1- 1-2033
Peaking Resource	1- 1-2036
Intermittent Resource	1-1-2028
Intermittent Resource	1-1-2030
Intermittent Resource	1-1-2034
Intermittent Resource	1-1-2034

Table 8-5
Resource Optimizer Plan Summary

Cumulative Min Power Supply	Incremental Power Supply	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan
-112	0	2022	Peaking						
			Intermediate						
			Renewable						
			Seasonal PPA	100	100	100	100	100	**100**
-182	-70	2023	Peaking						
			Intermediate						
			Renewable						**110**
			PPA						
-237	-55	2024	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA					100	
-288	-51	2025	Peaking						
			Intermediate						
			Renewable						
			PPA						
-325	-37	2026	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA						
-348	-23	2027	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA	100					
-346	2	2028	Peaking						
			Intermediate						
			Renewable					100	
			Seasonal PPA						
-334	12	2029	Peaking						
			Intermediate						
			Renewable		100				
			Seasonal PPA						
-314	21	2030	Peaking						
			Intermediate						
			Renewable					100	
			Seasonal PPA						
-285	28	2031	Peaking						
			Intermediate						
			Renewable		200		100		**200**
			Seasonal PPA						
-228	57	2032	Peaking	225			225		**225**
			Intermediate						
			Renewable						**200**
			Seasonal PPA						
-170	58	2033	Peaking		225			225	
			Intermediate						
			Renewable		100		100		
			Seasonal PPA				100		
-93	77	2034	Peaking			225			
			Intermediate						
			Renewable					200	
			Seasonal PPA						
3	95	2035	Peaking						
			Intermediate						
			Renewable			100			
			Seasonal PPA		100				
105	102	2036	Peaking				225	225	
			Intermediate						
			Renewable						
			Seasonal PPA						

These five plans were reviewed to determine if the operation dates of the near term resources were in fact achievable based on recent experience.

Since energy market prices and natural gas prices are correlated to the load data, and the load data simulates various weather patterns including periods of high and low loads, the result is a robust simulation of a variety of load and market conditions. Risk analysis is thereby incorporated into the simulation.

8.5 Reliability Criteria and Projected Capacity Needs

As stated in Section 6, Transmission and Distribution Planning, EKPC is a member of SERC. SERC promotes the development of reliability and adequacy arrangements among the systems; participates in the establishment of reliability standards; administers a regional compliance and enforcement program; and provides a mechanism to resolve disputes on reliability issues. As a member of PJM and SERC, EKPC plans to meet its PJM capacity resource requirements as well as plans to economically hedge its winter peak load expectations. See the table below for the total amount of capacity expected to be required on the EKPC system.

Table 8-6
EKPC Projected Capacity Needs
(MW)

Year	Projected Peaks		Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	3,315	2,498	0	75	3,315	2,573	3,434	3,132	-119	-559
2023	3,360	2,568	0	77	3,360	2,645	3,434	3,132	-75	-487
2024	3,376	2,605	0	78	3,376	2,683	3,434	3,132	-58	-449
2025	3,380	2,613	0	78	3,380	2,691	3,434	3,132	-54	-441
2026	3,395	2,622	0	79	3,395	2,701	3,434	3,132	-40	-431
2027	3,410	2,636	0	79	3,410	2,715	3,434	3,132	-24	-417
2028	3,437	2,652	0	80	3,437	2,732	3,434	3,132	2	-401
2029	3,447	2,668	0	80	3,447	2,748	3,434	3,132	12	-384
2030	3,456	2,680	0	80	3,456	2,760	3,434	3,132	22	-372
2031	3,464	2,698	0	81	3,464	2,779	3,434	3,132	30	-353
2032	3,495	2,698	0	81	3,495	2,779	3,434	3,132	61	-353
2033	3,496	2,726	0	82	3,496	2,808	3,434	3,132	62	-324
2034	3,516	2,743	0	82	3,516	2,825	3,434	3,132	82	-308
2035	3,535	2,764	0	83	3,535	2,847	3,434	3,132	101	-285
2036	3,543	2,777	0	83	3,543	2,860	3,434	3,132	109	-273

Notes:
1. Reserve requirement based on EKPC's pro-rata share of the PJM Summer reserve requirements. EKPC seeks to hedge its winter energy exposure for price stability, but has no winter capacity obligation to satisfy its PJM load serving oblication.

Table 8-7 below shows the expected capacity and energy price hedge additions based on the 2021 IRP plan.

Table 8-7
EKPC Projected Additions and Reserves
(MW)

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserve Requirements[13]		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,434	3,136	0	75	4%	25%
2023	110					3,434	3,198	0	77	2%	22%
2024	200					3,434	3,318	0	78	2%	20%
2025						3,434	3,318	0	78	2%	20%
2026	200					3,534	3,438	0	79	1%	19%
2027	200					3,534	3,558	0	79	1%	19%
2028						3,534	3,558	0	80	0%	18%
2029						3,534	3,558	0	80	0%	17%
2030						3,534	3,558	0	80	0%	17%
2031	200					3,534	3,678	0	81	0%	16%
2032[14]	200			225	170	3,659	3,968	0	81	5%	22%
2033						3,659	3,968	0	82	5%	21%
2034						3,659	3,968	0	82	4%	20%
2035						3,659	3,968	0	83	4%	19%
2036						3,659	3,968	0	83	3%	19%

EKPC will work with Federal and State stakeholders to ensure the economic viability of future and existing resources to meet the challenges and opportunities surrounding climate change. EKPC is driven to use its assets to deliver reliable, affordable and sustainable energy from appropriately diversified fuel sources. EKPC will carefully manage its portfolio of assets and pursue diversity of supply resources, including DSM/EE programs, market-based opportunities and risk related to climate change regulation/legislation. EKPC will continue to research and learn about related issues and opportunities.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional resources will continue to be required as the system shifts to renewable and clean

[13] Based on PJM reserve requirements
[14] Only generation added for the purpose of covering summer peak load capacity obligations is considered "capacity" additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply "capacity" to its portfolio or the PJM system.

energy resources. These conventional resources will continue to be needed to maintain reliability through the transition and into the future.

Table 8-8

Power Transactions (GWH)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Purchases	180	153	150	146	142	143	143	145	142	145	147	145	145	156	174
Market Purchase	14,318	15,208	15,657	15,966	16,283	16,818	17,177	17,277	17,370	17,695	18,294	18,621	18,770	18,924	19,105
SEPA	257	257	258	260	257	257	257	256	259	260	258	257	257	256	262
Total Purchases	16,777	17,642	18,089	18,398	18,707	19,246	19,605	19,708	19,800	20,131	20,731	21,056	21,206	21,372	21,577
Market Power Sales	13,320	11,703	11,973	11,104	11,405	11,120	11,224	11,226	11,454	11,389	11,703	11,420	10,851	10,853	10,870

Table 8-9

Non-Utility Generation (GWH)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Non-Utility Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* Generation from solar and landfill-gas-to-energy projects are included in the response to 8.(3)(b) and 8.(4)(c).

In the next several years, approximately 3,500 MWh of energy per year will be supplied from cogeneration and approximately 100,000 MWh of energy per year from LFGTE (self-generated).

Table 8-10

Forecast Energy	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Requirements (GWh)	14,421	15,193	15,306	15,397	15,498	15,601	15,741	15,841	15,934	16,044	16,210	16,319	16,468	16,621	16,802
Generation (GWH)															
Coal	11,407	10,171	10,085	9,183	9,380	8,796	8,702	8,719	8,823	8,575	8,302	7,876	7,476	7,538	7,605
Natural Gas	1651	1150	1170	982	875	741	721	705	829	794	950	876	707	648	592
Landfill Gas	95.2	95.1	95.3	95.1	95.1	95.1	95.4	95.1	95.1	95.1	95.3	95.1	95.1	95.1	95.3
Solar	13.8	4744.3	18148.3	26877.4	35478.4	52809.9	61547.7	61540.1	61540.1	70141.2	87482.1	96202.9	96202.9	96202.7	96214.3
Total	13,166	16,161	29,498	37,138	45,829	62,441	71,066	71,060	71,286	79,606	96,830	105,050	104,481	104,483	104,507
Purchases (GWH)															
Firm Purchases-SEPA	257	257	258	260	257	257	257	256	259	260	258	257	257	256	262
Firm Purchases-Other Utilities	180	153	150	146	142	143	143	145	142	145	147	145	145	156	174
Firm Purchases-Non-Utilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	437	410	408	406	399	401	400	402	401	405	405	402	402	413	436

Table 8-11

Fuel Input (1,000s MBTU)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	113,802	101,261	100,516	91,994	94,010	88,351	87,468	87,635	88,754	86,316	83,629	79,504	75,602	76,194	76,851
Natural Gas	16,928	11,649	11,932	9,962	8,849	7,487	7,250	7,101	8,333	7,976	9,753	9,013	7,251	6,603	6,068
Total	130,730	112,910	112,448	101,956	102,860	95,838	94,718	94,736	97,086	94,291	93,382	88,518	82,853	82,797	82,920
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,984	4,455	4,426	4,054	4,147	3,901	3,862	3,868	3,918	3,812	3,696	3,516	3,346	3,372	3,401
Natural Gas (1,000s mcf)	16,685	11,482	11,760	9,819	8,722	7,380	7,146	6,999	8,213	7,861	9,612	8,884	7,146	6,508	5,981

807 KAR Section 8(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

EKPC only operates within the state of Kentucky.

SECTION 9.0

COMPLIANCE PLANNING

SECTION 9.0

COMPLIANCE PLANNING

9.1 Introduction

EKPC works diligently to be a proactive and forward thinking prudent electric utility and has taken several actions as listed below to comply with the Clean Air Act ("CAA"), Clean Water Act ("CWA"), Resource Conservation and Recovery Act ("RCRA").

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards ("NSPS");
  - NSPS GHG for New, Modified and Reconstructed Fossil Fueled Units;
- New Source Review ("NSR");
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Cross State Air Pollution Rule ("CSAPR");
- National Ambient Air Quality Standards ("NAAQS") for Sulfur Dioxide ("SO_2"), Nitrogen Dioxide ("NO_2"), Carbon Monoxide ("CO"), Ozone, Particulate Matter ("PM"), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Mercury Air Toxics Standards ("MATS");
- EPA Affordable Clean Energy Rule ("ACE"), formerly known as the Clean Power Plan (vacated by the D.C. Circuit);

EKPC is currently in compliance with the following other environmental rules affecting the power generation sector:

- Clean Water Act ("CWA");
  - Section 316(a) and (b)
  - Effluent Limitations Guidance ("ELG")
  - Waters of the United States ("WOTUS")
- Resource Conservation and Recovery Act ("RCRA")
  - Coal Combustion Rule ("CCR");

EKPC is in compliance with the existing Environmental Protection Agency ("EPA") rules. As a prudent utility, we survey the environmental waterfront for future rules, in draft, proposed and final form. The Biden Administration has announced goals that depart from the prior Trump Administration's focus on cooperative federalism. The new Administration's goals are generally at odds with coal-fired power generation. Specifically, the Administration has put forth a goal of carbon-free electrical generation by 2035 (Executive Order ("EO") 14008). While the desire to reduce coal from the generating mix is clear, the timing and regulatory approach for implementing this policy is less clear. Regulations and guidance implementing these policies are forthcoming.

The existing infrastructure and transmission grid will not support a carbon-free goal in the power sector by 2035 and a net zero economy by 2050. Furthermore, this goal may not be achievable without some type of technology that includes rotating generation equipment. Coal generation would need to be replaced, which requires the commissioning of new assets and new technologies to maintain grid resiliency and reliability. This takes time for technology maturation, project planning, permitting, financing and construction. EKPC and the power industry are working with several groups including the Electric Power Research Institute ("EPRI") to develop reasonable and practicable timelines. The power industry is evaluating and anticipating changes based on the Biden Administration's agenda. For instance, the Biden Administration has already issued a list of final environmental rules that it will be reconsidering, which are discussed herein.

The EPA issued a draft 2018-2026 Strategic Plan on October 1, 2021 (EPA Plan) that provides highlights of the Biden EPA's new initiatives. The EPA Plan adds tackling climate change and environmental justice to the existing general categories of focus, which are enforcement and compliance of existing laws and regulations, improvement of outdoor and indoor air quality, ensuring clean and safe water for all communities, safeguard and revitalize communities, and ensure safety of chemicals for people and the environment.

Environmental justice is a particular focus of the Biden Administration. President Biden released an EO on *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government* on January 20, 2021. This EO established a comprehensive approach to advancing equity across the federal government, including an assessment of certain agency programs to assess whether underserved communities face systemic barriers in accessing benefits and opportunities and whether new policies, regulations or guidance documents may be necessary to advance equity in agency actions and programs. On April 7, 2021, EPA Administrator Michael Regan responded to the Biden EO by announcing new EPA measures to:

1. Strengthen enforcement of violations of cornerstone environmental statutes and civil rights laws in communities overburdened by pollution.

2. Take immediate and affirmative steps to incorporate environmental justice considerations into their work, including assessing impacts to pollution-burdened, underserved, and Tribal communities in regulatory development processes and to consider regulatory options to maximize benefits to these communities.

3. Take immediate and affirmative steps to improve early and more frequent engagement with pollution-burdened and underserved communities affected by agency rulemakings, permitting and enforcement decisions, and policies. Following President Biden's memorandum on strengthening the Nation-to-Nation relationship with Tribal Nations, EPA staff should engage in regular, meaningful, and robust consultation with Tribal officials in the development of federal policies that have Tribal implications.

4. Consistent with the Administration's Justice 40 initiative, consider and prioritize direct and indirect benefits to underserved communities in the development of requests for grant applications and in making grant award decisions, to the extent allowed by law.

EKPC's service area includes a significant number of end users in economically distressed communities. As such, there may be opportunities for increased funding directed toward bringing energy and efficiency programs to those areas, through RUS electric programs.

EKPC is complying with the current rules of environmental law. A description of each rule appears below and lays out what impacts are expected.

I. NSR

EKPC dedicates ongoing legal, operations, and environmental resources to the review of outage projects under its NSR compliance program. EKPC remains in compliance with the conditions of the 2007 Consent Decrees that were designed to survive termination through EKPC's air permits. Congress and the EPA considered reforms to the NSR rules that would have created a bright line test to determine whether a project requires a PSD permit. However, the Trump EPA did not accomplish any regulatory changes to this effect and legislation stagnated. In 2021, the Biden EPA has not made any significant changes to the NSR Program. However, on October 12, 2021, the EPA disclosed plans to initiate a rulemaking process to consider revisions to NSR regulations. EKPC will monitor future developments.

II. EGU Mercury Air Toxics Standards

On March 16, 2011, EPA issued the proposed EGU MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA MATS as the EGU

MACT rule on December 16, 2011, to reduce emissions of heavy metals, including mercury ("Hg"), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride ("HCl") and hydrogen fluoride ("HF"). MATS allow sources to control surrogate emissions to demonstrate control of HAP metals and HAP acid gases. Non-Hg metallic toxic air pollutants are captured by PM emission limits because these metals travel in particulate form in boiler gas paths. HCl and /or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms. Under MATS, mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance. EGUs began compliance with the mercury, SO_2 or HCl, and PM limits for MATS beginning in the spring of 2015.

Since the MATS rule is a Section 112 rule, other provisions in § 112 are relevant. Namely, Section 112(d)(6) requires EPA to "review and revise as necessary emission standards promulgated under this section no less often than every 8 years." Also, Section 112(f) states, among other things, "if standards promulgated pursuant to subsection (d) and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million, the Administrator shall promulgate standards under this subsection for such category." Taken together, these two provisions constitute what is called EPA's Risk and Technology Reviews ("RTR").

On December 27, 2018, EPA proposed to revise the Supplemental Cost Finding for MATS and the Clean Air Act required RTR. EPA promulgated the MATS RTR Final Rule on May 22, 2020. The Rule dictates that MATS remain in place although it concluded that it was not "appropriate and necessary" to regulate HAPs for EGUs. The Rule found that the costs of regulation outweigh the benefits of HAP emissions reductions. No change in the MATS Rule occurred as a result of this rulemaking. The MATS RTR Final Rule is on the Biden Administration's list of rules to be reconsidered. In response, EPA has reconsidered the Final Rule. Presently, the Office of Budget and Management ("OMB") is reviewing EPA's proposal entitled, "NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units--Reconsideration of Supplemental Cost Finding and Residual Risk and Technology Review." The content of the rulemaking has not been released.

EKPC continues to comply with the MATS Rule using a combination of strategies. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of the NSR Consent Decrees, placed EKPC's units ahead of most EGU units for MATS compliance with minimal additional capital investment. Likewise, Spurlock 3 and 4 are equipped with Best Available Control Technology ("BACT") and met the MATS rule limits without additional controls. The dry scrubbed units in the EKPC coal-fired fleet have achieved low emitting EGU ("LEE") status for HCl. EKPC is currently in compliance with MATS requirements and monitors its units to assure ongoing compliance.

III. <u>Cross-State Air Pollution Rule</u>

On July 6, 2011, EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaced EPA's 2005 CAIR rule that was remanded to EPA by the U.S. District Court of Appeals for the D.C. Circuit (D.C. Circuit). CSAPR required significant reductions in SO_2 and nitrogen oxides ("NO_X") emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the NAAQS. The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. On December 30, 2011, CSAPR was stayed by the D.C. Circuit in response to industry petitions challenging the rule. On August 21, 2012, CSAPR was vacated and remanded back to EPA. EPA appealed this decision and on April 29, 2014, the Supreme Court reversed the D.C. Circuit and reinstated CSAPR. The Court remanded the rule back to the D.C. Circuit to determine next steps and resolve the many pending appeals of the rule. On June 26, 2014, EPA asked the D.C. Circuit to lift the stay on CSAPR but toll the original compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the motion and as a result, CSAPR was reinstated with Phase 1 beginning January 1, 2015 and Phase 2 starting January 1, 2017.

In November 2016, EPA proposed the CSAPR Update Rule ("CSAPR II"), addressing earlier court concerns and interstate transport of air pollution under the 2008 ozone NAAQS. The updated rule became effective on December 27, 2016. The updated rule did not affect the SO_2 allocations or the NOx allocations for 2015 and 2016. The D.C. Circuit in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019) found that CSAPR II only partially addressed downwind contributions from upwind states by the 2018 moderate ozone nonattainment NAAQS attainment date. The court remanded the rulemaking back to EPA. In response to the remand, the EPA Administrator signed the final CSAPR Update Rule on March 15, 2021 (the 2021 CSAPR Update).

EPA adopted substantial emission reductions for electric generating units ("EGUs") in 12 states beginning in the 2021 summer ozone season, with diminishing reductions in 2022-2023 that reduce NOx seasonal allowance allocation budgets and current banked allocations held by EGUs. State-wide NOx Ozone Season Emission Budgets reduce allocations based on optimization of existing SCRs and SNCRs. Kentucky is included among the 12 states that must participate in a new CSAPR NOx Ozone Season Group 3 Trading Program similar to the Group 2 Trading Program. EPA justified further reducing emissions from these states because it found that the states' projected 2021 emissions contribute at or above a threshold of 1% of the NAAQs (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.

The 2021 CSAPR Update made meaningful material reductions in the allocation budgets of the EKPC fleet. EKPC will be closely monitoring its ozone season NOx emissions to determine whether its allocations will continue to cover the NOx tons emitted. EKPC's state-of-the-art NOx controls are already optimized with little headroom for improvement. Therefore, EKPC would be required to address any shortfall via purchase of NOx allowances, projected at a premium cost, or unit curtailment since EPA significantly reduced the banked allowances earned as super compliance.

EKPC filed comments in the federal rulemaking docket for the 2021 CSAPR Update as did other utilities and the Midwest Ozone Group ("MOG"), of which EKPC is a member. MOG has challenged the 2021 CSAPR Update Rule in the D.C. Circuit in *Midwest Ozone Group v. EPA and Administrator Regan*. MOG argues that EPA undertook inappropriate "shortcuts," in computer modeling, procedurally, carved out banked allowances without notice and otherwise when addressing the D.C. Circuit's remand of the rule. A decision is not expected until mid to late 2022.

CSAPR is due for an update, even though the 2021 CSAPR Update was just issued. The 2021 CSAPR Update is based on the 2008 Ozone NAAQS standard of 0.075 ppm. EPA will update CSAPR to align with the 2015 Ozone NAAQS standard of 0.070 ppm. It is likely that EPA will propose the reduction of allocations beyond the tightened budgets in place for 2021-2023 due to the more stringent 2015 Ozone NAAQS standard. We project this change to take effect in 2023, or thereafter.

IV. GHG Tailoring Rule

On May 13, 2010, the EPA issued a final rule that established emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule set GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane ("CH_4") into a combined CO_2 equivalent ("CO_{2e}").

Under the original GHG Tailoring rule, if any of the stations made a physical or operational change that would result in a net increase of 75,000 tons per year or more of CO_{2e}, EKPC must have obtained an NSR permit for the modification including the installation of BACT for GHGs on the modified unit.

On June 23, 2014, the U.S. Supreme Court struck part of the GHG Tailoring Rule and held that a significant net emissions increase in GHGs alone cannot trigger NSR. NSR permitting requirements for GHGs can be triggered, but only if the physical or operational change also results in both a significant net emissions increase of GHGs and another PSD pollutant. On October 3, 2016, EPA responded to the Court's action by issuing a Proposed Rule that sets the GHG significant emissions rate at 75,000 tons per year or more of CO_2. But until EPA issues a Final Rule, the GHG threshold will not be set. EKPC is tracking these developments.

V. National Ambient Air Quality Standards ("NAAQS")

If a county or counties is designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement RACT retrofits to bring the areas into attainment. Further, no permits can be approved by the Cabinet without a NAAQS compliance demonstration, which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

A. CO

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 31, 2011. As of September 27, 2010, all CO areas have been designated as maintenance areas. On April 11, 2014, the D.C. Circuit deferred to EPA's authority to set NAAQS, maintain the primary standard from 1971 and not set a secondary standard.

B. SO_2

EPA revised the primary SO2 NAAQS in June 2010 to a one-hour standard of 75 ppb. The current secondary 3-hour SO_2 standard is 0.5 ppm. On March 18, 2019, EPA issued a Final Rule to keep the existing one-hour primary standard of 75 parts ppb of SO_2 after weighing potential changes, including altering the formula for how the agency determines whether an area is attaining or violating the NAAQS. This rulemaking is one of the rulemakings to be reconsidered by EPA under a Biden EO entitled *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, dated January 20, 2021. However, this action did not appear in the list of agency actions to be reviewed in the non-exclusive list published on that same date.[15] It also does not appear in the most recent 2021 Unified Agenda under the list of EPA actions to be reconsidered.[16]

In 2011, Jefferson County, adjacent to Oldham County where Bluegrass Station is located, was designated as a non-attainment area. However, it has been converted to a maintenance area. A gas-fired facility can control SO_2 using low sulfur fuels. EKPC's coal-fired units are located in areas in attainment with the SO2 NAAQS. EKPC will continue to monitor future developments, should the Biden Administration attempt to lower the SO_2 NAAQS either in the normal statutory course of NAAQS five-year reviews (CAA, Section 109) by the Clean Air Scientific Advisory Committee ("CASAC") or by reconsideration of the 2019 final rule.

C. NO_2

EPA revised the primary NO_2 NAAQS in January 2010. The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the Commonwealth be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire

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[15] *Fact Sheet: List of Agency Actions for Review*, www.whitehouse.gov (Jan. 20, 2021).

[16] 2021 EPA Unified Agenda (07/30/2021), https://www.federalregister.gov/documents/2021/07/30/2021-14882/spring-2021-unified-agenda-of-regulatory-and-deregulatory-actions.

country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the Commonwealth responded to EPA's proposed revision requesting that the areas that show compliance with area monitors are designated as attainment and that the remainder of the Commonwealth be designated as unclassifiable/attainment. Final designation of the entire United States as unclassified/attainment was made on February 17, 2012. A new monitoring system was implemented to measure NO_2 concentrations. EPA finalized a rule establishing a nation-wide monitoring on March 7, 2013 in two phases (2014 and 2017). Three years after the new monitoring system was implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2020). An initial compliance deadline of 2025 is contemplated. On April 18, 2018, EPA finalized its periodic review of the NO_2 NAAQS one-hour standard of 100 ppb and the annual standard of 53 ppb to determine if these existing standards are protective of public health and welfare. EPA retained both standards without revision.

D. Ozone

On December 20, 2017, EPA provided notice to Governor Bevin of Kentucky concerning the air quality designations for the revised 2015 NAAQS Ozone Standards throughout Kentucky. The 2015 Ozone NAAQS Ozone Standard lowered the 8-hour ozone standard from 0.075 ppm to 0.070 ppm. On December 31, 2020, EPA finalized its review of the Ozone NAAQS and decided to maintain the current standard (0.070 ppm). However, the Biden Administration has opted to reconsider this rulemaking. It is also subject to the CRA. *See* 85 Fed. Reg. 87256 (Dec. 31, 2020).

The 2015 NAAQS Ozone Standard designations affect Bluegrass Station, owned and operated by EKPC, located in Oldham County, which is designated nonattainment as an area contributing to a 2015 NAAQS Ozone Standard violation. EKPC filed comments on this designation on February 5, 2018. All other EKPC generation facilities are located in areas in attainment with the standard. The 2017-2019 three-year average was below the level of the standard for all Kentucky sites except for Cannons Lane (Jefferson County), although Oldham County remains designated marginal nonattainment. EKPC will follow developments and assess any impacts on Bluegrass Station.

E. <u>Particulate Matter (“$PM_{2.5}$”)</u>

In 1997, EPA adopted the 24-hour fine particulate NAAQS (“$PM_{2.5}$”) of 65 µg/m^3 and an annual standard of 15 µg/m3. In 2006, EPA revised this standard to 35 µg/m^3, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire Commonwealth was designated as unclassifiable/attainment under the 2006 standard.

EPA tightened the primary $PM_{2.5}$ NAAQS to 12 µg/m^3 on January 15, 2013. On January 15, 2015, EPA issued final $PM_{2.5}$ designations. EPA designated Boone, Campbell, Keaton, Bullitt and Jefferson counties as non-attainment. EKPC does not have facilities in these counties. On December 18, 2020, EPA finalized its review of the PM NAAQS and decided to maintain the current standard. However, the Biden Administration has opted to reconsider this rulemaking. It is also subject to the Congressional Review Act (“CRA”). *See* 85 Fed. Reg. 82684 (Dec. 18, 2020).

On October 8, 2021, EPA published a draft Policy Assessment paper that provides the scientific basis and recommendation to make the $PM_{2.5}$ NAAQS more stringent. The magnitude of any decrease may impact EKPC facilities in other counties. At present, Kentucky reports in its Annual Report for 2021 that the $PM_{2.5}$ values in Kentucky have decreased over time from 1999 to present with a current state-wide average lower than the present standard of 12 µg/m3 (below 10 µg/m3). *See* Kentucky’s Air, Kentucky Division for Air Quality, 2021. Emission values remain the highest in counties near the Louisville metropolitan area. It is uncertain whether EPA can justify a reduction to the degree that it will impact counties outside of the Louisville area.

F. <u>Lead</u>

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 µg/m^3 to 0.15 µg/m^3 in a three month period averaging time. EPA has designated the Commonwealth as unclassifiable/attainment for the lead NAAQS. EPA retained this standard on October 18, 2016 in a Final Rule.

VI. <u>Regional Haze Rule</u>

The Regional Haze Rule has triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. This first review, just now being completed, targets Best Available Retrofit Technology ("BART") controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. Spurlock and Cooper Stations are subject to BART. EKPC submitted its Regional Haze compliance plans to the Cabinet, and the Cabinet submitted the plan for the Commonwealth to EPA, who adopted it formally into Kentucky's SIP on April 8, 2019. 84 Fed. Reg. 13800 (Apr. 8, 2019). EKPC installed SO_2, NOx and PM controls on Spurlock 1 and 2 and Cooper 2 to comply with the NSR Consent Decrees, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. At this point, Spurlock and Cooper Stations' compliance with CSAPR equals Regional Haze Rule/BART compliance. EPA re-affirmed that CSAPR compliance is sufficient to meet Regional Haze criteria. 85 Fed. Reg. 40286 (July 6, 2020). EKPC's coal-fired fleet has remained in compliance with BART since its compliance date of April 2017 and is in compliance with the BART provisions in its Title V permits. The Program requires reasonable progress reports every five years and revised Regional Haze Plans every 10 years. The next plan revision is due in 2028.

Regional Haze goals could become more stringent, if EPA determines in the future that CSAPR no longer satisfies BART compliance goals. It is also possible that EPA could alter the BART analysis using differing modeling inputs, visibility benefits, and cost analysis (e.g., with the addition of social costs) to require a more stringent BART Plan. In this way, EPA could choose to use BART as a mechanism to seek future NOx and SO2 reductions from the power sector. At present, changes to the BART program are uncertain.

VII. New Source Performance Standards Under Sections 111(b) and 111(d) for Carbon Dioxide Emissions

Regulation of carbon dioxide emissions under the New Source Performance Standards (NSPS) in the CAA have fluctuated considerably in the last five years. EPA has attempted to put in place NSPS requirements for CO_2 that apply to new sources (Section 111(b)) and existing sources (Section 111(d)), which has become a politically charged issue. This section briefly summarizes past efforts and the current status of regulations.

A. Clean Power Plan

The Obama Administration promulgated the final CPP in 2015. For EKPC, the rule required a drastic reduction in fossil fuel-fired generation in Kentucky. The Rule also required a 32-percent reduction in carbon dioxide emissions from the 2005 levels by 2030, a costly and unexpected additional decrease of 27% from the previously proposed rule's aggressive 2030 goal. The Supreme Court stayed the CPP on February 9, 2016.

On March 28, 2017, President Trump signed EO 17833, entitled *Promoting Energy Independence and Economic Growth*, directing the EPA to review and, if appropriate, suspend, revise, or rescind the CPP. EPA announced its intent to review and, if appropriate, suspend, revise or rescind the CPP on April 4, 2017. Subsequently, EPA proposed a rule repealing the CPP on October 16, 2017. Comments on the proposed repeal rule were filed April 26, 2018. Industry comments focused on all the legal flaws in the CPP. NRECA and individual G&Ts (including EKPC) focused on the disparate impact that the existing CPP would have on electric cooperatives. Rather than finalizing this Proposed Rule, EPA opted to repeal the CPP in the ACE rulemaking, discussed *infra*.

This repeal positively impacted EKPC. The prior rule assumed an unrealistic improvement in efficiency from coal units. EKPC is a leader in heat rate improvement measures and has some of the best performing units. Most of the feasible efficiency improvements have been made and any additional requirements may unfairly penalize EKPC for having made these improvements.

B. Affordable Clean Energy Rule

EPA issued the Proposed (ACE Rule to replace the CPP on August 21, 2018. EPA's general approach to the rule was to clarify the federal and state roles in rulemaking known as cooperative federalism, with particular emphasis on granting states more authority to make decisions about how to implement the ACE. EPA published the Final ACE Rule on July 8, 2019. The ACE Final Rule repealed and replaced the CPP. EPA sets BSER and provides guidance to the states on how to apply BSER. States apply BSER on a unit basis to set standards of performance (short term CO_2 emissions rate limits CO_2 lbs./MWh). States are charged with examining potential technologies and operation and maintenance practices that could potentially improve the efficiency of individual coal units and result in a reduction in CO_2 emissions. The units will combust less coal but generate the same amount of electricity. All resulting limits must be set based on the CO_2 emissions rate from a unit (pounds of CO_2 emitted per megawatt hour generated). States have three years to prepare a plan implementing the Rule. EKPC worked on the implementation process in 2020 to provide information to Kentucky in preparation for its plan submittal. The Kentucky Division of Air Quality ("DAQ") granted an extension to the EGUs in Kentucky until Spring of 2021.

The Final ACE Rule was challenged in the D.C. Circuit by numerous ENGOs and public health organizations, with states and industry participation in amicus curiae briefing in *American Lung Ass'n v. EPA*. On January 19, 2021, the D.C. Circuit vacated ACE, the CPP Repeal Rule and the challenged timing provisions within the implementing regulations, and remanded the actions to EPA for further proceedings consistent with its opinion.[17] The Court did not expressly reinstate the CPP. EPA has followed up in a memorandum to the EPA Regions to clarify that states do not have any current obligations under the CPP or ACE. DAQ postponed their requirement indefinitely for EGUs to submit ACE plans.

To summarize, there is currently no Section 111(d) rule in place for existing power plants. Leadership in the Biden Administration indicates that the CPP will not be reinstated. Rather, industry anticipates EPA to develop and propose a new Section 111(d) rule to reduce carbon dioxide emissions from existing coal-fired EGUs as well as other significant industrial sources (transportation, oil and gas industry) post-oral arguments and a hearing of WV v. EPA by the Supreme Court that began February 28, 2022. To the extent the Biden EPA has made any decisions regarding how to proceed in developing Section 111(d) rules, no specifics have been made public. EPA could pursue a specific carbon emission limit, plant-wide caps, technology requirements, a trading program, or a combination thereof. EKPC will continue to monitor regulatory developments and their impact on their fleet.

[17] *American Lung Ass'n v. EPA*, 2021 WL 162579 (D.C. Cir. Jan. 19, 2021).

C. CO2 NSPS for New Utility Coal and Natural Gas units (Section 111(b) Rule)

EPA released proposed revisions to the 111(b) CO_2 rule (Proposed Rule) on December 6, 2018. The current 111(b) CO_2 rule applies, as do all 111(b) rules, to new EGUs. The primary goal of the Proposed Rule is to revise EPA's former finding that partial Carbon Capture and Sequestration ("CCS") was the best system of emissions reduction ("BSER") for CO_2 emissions from EGUs. The Proposed Rule determines that CCS is too costly, technically infeasible and geographically limited. Instead, EPA proposes to set BSER as units with the most efficient demonstrated steam cycle in combination with best operating practices.

Supercritical units (which includes ultra-supercritical units) are BSER for units with a heat input larger than 2,000 MMBtu/h. For units with a heat input equal to or less than 2,000 MMBtu/h highly efficient subcritical units. The resulting emissions limits (Table 1) apply to new and reconstructed EGU and are a floor for modified EGUs. Coal refuse EGUs have a slightly higher limit.

Table 1. Summary of BSER and Proposed Standards for Affected Sources

Affected Source	BSER	Emissions Standard
New and Reconstructed Steam Generating Units and IGCC Units	**Most efficient generating technology in combination with best operating practices**	**1. 1,900 lb CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h 2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or 3. 2,200 lb CO2/MWh-gross for coal refuse-fired sources**
Modified Steam Generating Units and IGCC Units	**Best demonstrated performance**	**A unit-specific emission limit determined by the unit's best historical annual CO2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than 1. 1,900 lb CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h 2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or 2,200 lb CO2/MWh-gross for coal refuse-fired sources**

There is no change to new unit limits for combustion turbines, including NGCC units. These limits are:

1. 1,000 lb CO2/MWh-g or 1,030 lb CO2/MWh-n for base load natural gas-fired units.
2. 120 lb CO2/MMBtu for non-base load natural gas-fired units.
3. 120 to 160 lb CO2/MMBtu for multi-fuel-fired units.

The Proposed Rule uses a modification rule test that contemplates determining whether a modification triggers 111(b) by comparing hourly CO_2 emissions rates after change with the highest hourly emissions rate in the five years before. This test is contrary the traditional NSPS modification test under 60.14(h) which looks at the maximum achievable hourly emissions rates in the five years before the project compared to hourly rates going forward. However, it is more consistent with the proposed NSR hourly emissions rate alternatives in the ACE proposal.

The Proposed Rule very briefly discusses the 2009 endangerment finding and the lack of an additional endangerment finding when the 111(b) Rule was promulgated in 2015, but makes clear that EPA is not re-opening these issues or inviting comment on them. EPA seems unlikely to change the legal basis for the 111(d) Rule. No Final Rule has been issued.

However, EPA did issue a *Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories*, 86 Fed. Reg. 2542 (Jan. 13, 2021). This final rule provides criteria for making a significant contribution finding for GHG emissions from a source category, for the purpose of regulating those emissions under Section 111(b) of the CAA. The framework sets an emissions threshold of 3 percent of total gross United States GHG emissions from a stationary source category as the primary criterion in making a pollutant-specific significance determination. This rulemaking is on the Biden Administration's list of rulemakings to be reconsidered, although EPA has not acted on this final rule to-date.

NON-CAA RULES WITH REGULATORY CHANGES

For completeness EKPC is providing a summary of new CWA rules and Proposed Rules to change portions of the CCR rule.

A. CWA Section 316(a)

The CWA, Section 316(a) applies to point sources with thermal discharges. It authorizes the NPDES permitting authority – the Kentucky Division of Water ("KDOW") – to impose alternative thermal effluent limitations in lieu of the requirements that would be required under Sections 301 and 306 of the CWA. To obtain an alternative effluent thermal limitation, the permittee must demonstrate that the thermal limit is stringent enough to assure protection and propagation of a balanced, indigenous population ("BIP") in and on the body of water into which the discharge is made.

Cooper Station currently has an alternative thermal effluent limit (daily maximum limit of 100 degrees F) under Section 316(a) at Outfall 003, which handles once-through cooling water. Condition 5.7 of Cooper Station's KPDES permit requires that EKPC request continuation of this limitation in its next KPDES permit renewal application, which is due by December 31, 2022. EKPC plans to request that KDOW renew this alternative limit.

EKPC is in the process of developing a thermal plan study to support the renewal of this alternative thermal limit. The demonstration will include consideration of the following key elements, which is consistent with EPA Region 4 guidance:

- biotic community typically characterized by diversity;
- the capacity to sustain itself through cyclic seasonable changes;
- presence of necessary food chain species; and
- lack of domination of pollution-tolerant species.

In addition, EKPC will follow the KDOW guidance issued in 2019 for permittees seeking thermal variances under Section 316(a). EKPC met with KDOW in June 2019 to discuss EKPC's demonstration plan. KDOW concurred with EKPC's plan. EKPC is preparing the demonstration to apply for renewal of the alternative thermal limitation.

B. **CWA 316(b) Rule**

The Clean Water Act, Section 316(b) regulates cooling water intake structures ("CWIS") at existing facilities. The rule sets requirements that establish Best Technology Available ("BTA") for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of CWIS. The rule became effective on October 14, 2014.

EKPC is currently in compliance with Section 316(b) at its two active coal-fired facilities subject to the Rule: Spurlock and Cooper Stations. These plants hold a Kentucky Pollutant Discharge Elimination System ("KPDES") permit. KDOW has the discretion to determine the plant-specific entrainment mortality mitigation requirements each time the KPDES permit comes up for renewal and to set a schedule for implementation of any new controls.

Spurlock Station's KPDES permit was issued by KDOW with a compliance date of January 1, 2019. The KPDES permit confirms that Spurlock Station's existing closed-cycle recirculating cooling water system is BTA for both impingement and entrainment under the final Section 316(b) existing facilities rule. EKPC does not anticipate additional future requirements given the cooling water system, metrics, and lack of threatened or endangered species in the Ohio River.

With respect to Cooper Station, its KPDES permit has an effective date of July 1, 2018. The permit includes a condition to prepare and submit a 316(b) demonstration for the Division "to establish impingement mortality and entrainment BTA requirements as applicable under 40 CFR 125.94(c) and (d)." This demonstration is to be included with the next KPDES permit renewal application due 180 days prior to permit expiration. KDOW must make an entrainment BTA determination under §125.98(f). EKPC will provide the Director with the relevant information to support the BTA decision with its Section 316(b) information submittal. EKPC believes that its current system is BTA for impingement and entrainment.

C. **Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category**

On November 3, 2015, EPA published the ELG final rule to regulate the quality of the wastewater that can be discharged from power plants. The ELG rule identifies effluent limits for arsenic, mercury, selenium, and nitrogen discharged from wet scrubber systems and zero discharge of pollutants in ash transport water. The original rule identified compliance between 2018 and 2023, depending upon a plant's NPDES permitting deadlines. The ELG rule was challenged in the United States Court of Appeals for the Fifth Circuit, which has resulted in further changes to the ELG rule as remanded by the court to EPA as to legacy wastewater and combustion residual leachate. On October 13, 2020, EPA promulgated the 2020 ELG Reconsideration final rule that establishes effluent limits for flue gas desulfurization ("FGD") wastewater and for bottom ash ("BA") transport water applicable to existing steam electric power generators, exclusively and did not revise any other waste streams. 85 Fed. Reg. 64650 (Oct. 13, 2020). The Biden Administration has identified this Rule in the list to be reconsidered and, on June 26, 2021, EPA announced decision to reconsider the stringency of the ELG regulations, promulgated under the Trump EPA. EPA plans to issue rulemaking by fall of 2022 and final rule in 2023.

Although ELG is a regulatory driver for many facilities, EKPC is well-positioned for compliance. Spurlock Station is installing a wastewater treatment system to handle wastewater prior to solid clarification and discharge (the Wastewater Treatment Project). The resulting effluent will be compliant with ELG BAT limitations. EKPC anticipates completion of the Wastewater Treatment Project prior to expiration of the Spurlock KPDES permit in September 2023.

D. **Waters of the United States**

WOTUS is a term that delineates federal jurisdiction over "navigable waters" under the Clean Water Act. It defines the scope of Clean Water Act programs such as water quality standards, oil spill prevention and preparedness, impaired waters and total maximum daily loads, NPDES permitting (discussed *supra* in the context of the ELG and Section 316 regulations), and permitting discharges of dredged or fill material. EKPC must comply with many of these Clean Water Act programs, which requires tracking any changes to the definition of WOTUS. Since EKPC borrows money from RUS, the National Environmental Policy Act is applicable to all EKPC capital projects. Capital projects are vetted through the RUS NEPA process for RUS Environmental and Engineering permitting and approval. Should any capital projects impact WOTUS, the NEPA process resultant report is reviewed and approved by RUS via the NEPA process, which includes public participation. As a cooperating regulatory federal agency, the United States Army Corp of Engineers ("USACE") reviews the environmental report or environmental assessment for their permit purposes and issues a Finding of No Significant Impact ("FONSI"), or an Environmental Assessment ("EA") as authorization of the project. Should the USACE identify impacts to WOTUS, the permit applicant must submit a mitigation plan and/or pay the mitigation fees, bank or self-mitigate the project.

The definition and scope of WOTUS has undergone political shifts lately, similar to the Section 111 air regulations. The Obama Administration released the 2015 WOTUS Rule that more broadly construed WOTUS than the prior Regulatory Definition of "Waters of the United States" from 1986/1988. On January 23, 2020, EPA, under the Trump Administration, and the Department of Army issued the Final Navigable Waters Protection Rule (the Navigable Waters Rule), which completed the two steps involved to rescind the 2015 Rule and revise the regulatory definition of WOTUS, which was published on April 21, 2020. 85 Fed. Reg. 22250 (Apr. 21, 2020). The Final Rule became effective on June 22, 2020 but was subject to federal district courts challenges across the country. On August 30, 2021, the federal district court in Arizona in *Pascia Yaqui Tribe v. EPA* vacated and remanded the Navigable Waters Rule to EPA. Based on this court order, EPA halted implementation of the Navigable Waters Rule. EPA is presently interpreting WOTUS using the "pre-2015 definition." However, EPA is working toward replacing the Navigable Waters Rule. On November 18, 2021, EPA released a pre-publication version of a proposed rule to revise WOTUS. The proposed rule calls for the reinstatement of the pre-2015 definition of WOTUS with updates to reflect relevant Supreme Court decisions. Kentucky previously utilized the pre-2015 definition for WOTUS and waters of the Commonwealth, therefore EKPC has experience with this interpretation.

E. **Coal Combustion Residual Rule**

On April 17, 2015, the EPA published a final rule regulating management of CCR under the Resource Conservation and Recovery Act. The CCR rule became effective on October 14, 2015. The final rule applies to landfills and surface impoundments that contain CCRs. The CCR rule establishes minimum national criteria for the safe disposal of CCR. The criteria address a wide spectrum of activities related to CCR. Areas addressed include location restrictions, structural integrity requirements, liner design criteria, operations, groundwater monitoring, closure and post-closure requirements. CCR includes fly ash, bottom ash, boiler slag and flue gas desulfurization materials.

The Water Infrastructure Improvements for the Nation ("WIIN") Act became effective law on December 16, 2016. Overall, the WIIN Act is comprehensive legislation that aims to improve the United States' water resources infrastructure. The WIIN Act also includes an amendment to the CCR Rule. Specifically, the WIIN Act allows for a state permit program for CCR management that is at least as protective as the federal coal combustion residual rule. The WIIN Act also granted the EPA authority to directly enforce the implementation of the CCR Rule and an approved state permit program. In the absence of an approved state program, the WIIN Act requires EPA to put its own program in place. Pursuant to the WIIN Act, EPA proposed to establish a federal CCR permit program for CCR management units. 85 Fed. Reg. 9940 (Feb. 20, 2020). The public comment period has concluded. No final rule has been promulgated. At this juncture, only Texas, Oklahoma, and Georgia have approved CCR state programs.

Certain provisions of the CCR rule were remanded back to EPA by the D.C. Circuit of Appeals for further action on June 14, 2016. On March 15, 2018, EPA proposed a rule to address these remanded issues. The key issue for the remand rule is for EPA to delay future CCR compliance deadlines. EPA published a final rule extending certain CCR compliance deadlines on July 30, 2018, known as Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One), 83 Fed. Reg. 36435 (July 30, 2018). This Rule is on the list of rules to be reconsidered by the Biden Administration.

The final rule provides for the following:

- Delayed the deadlines for CCR Units that have detected a statistically significant increase in a covered pollutant or cannot comply with aquifer requirements to close from six months to until October 31, 2020.
- Allows the suspension of groundwater monitoring for up to ten years where there is no potential for migration of CCR constituents to groundwater.
- Adds limits for cobalt, lithium, molybdenum, and lead.
- Allows State Directors of approved programs to approve compliance measures instead of a third-party professional engineer.

On August 22, 2018, the United States District Court for the District of Columbia issued an opinion in *USWAG v. EPA.* The court found that unlined impoundments are likely to leak, that contamination is likely to create an unacceptable risk to human health and the environment, and that only twice-yearly monitoring would allow leaks to go undetected. The court found that clay-lined impoundments are similarly insufficiently protective. The court further found that RCRA provides authority to regulate both active and inactive units and rejected the exemption for legacy ponds (described as a subset of inactive impoundments) as arbitrary and capricious.

In 2019, EPA published proposed rules that provided for substantial changes to the CCR federal regulatory scheme, many of which were in response to the *USWAG* decision and finalized some of these rules in 2020. These proposed and final rules include:

- Proposed Rule: Enhancing Public Access to Information; Reconsideration of Beneficial Use Criteria and Piles, 84 Fed. Reg. 403 53 (Oct. 15, 2019) (Some of the proposals were finalized in the Closure Part A Rule).
- Proposed Rule: Federal CCR Permit Program.
- Final Rule: Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure, 85 Fed. Reg. 53516 (Aug. 28, 2020) (Closure Part A).

- Final Rule: Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments, 85 Fed. Reg. 72506 (Nov. 12, 2020) (Closure Part B).

Although in each of these rulemakings, EPA has suggested significant changes and additions to the CCR Rule provisions for beneficial use, reporting, website posting, and impoundment liners, the Final Rules concerning closure have the most impact on EKPC's CCR compliance strategy.

On August 28, 2020, EPA issued revisions to the CCR Rule that require all unlined surface impoundments to cease receipt of CCR and non-CCR waste and initiate closure by April 11, 2021, unless an alternative deadline is requested and approved. 40 CFR § 257.101(a)(1), (b)(1) (85 Fed. Reg. 53516 (Aug. 28, 2020)), known as *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure* (Closure Part A.) Specifically, owners and operators of a CCR surface impoundment may seek and obtain an alternative closure deadline by demonstrating that there is currently no alternate capacity available on or off-site and that it is not technically feasible to complete the development of alternative capacity prior to April 11, 2021. 40 CFR § 257.103(f)(1). To make this demonstration, the facility is required to provide detailed information regarding the process the facility is undertaking to develop the alternative capacity by November 30, 2020. 40 CFR § 257.103(f)(1). Any extensions granted under this Section cannot extend past October 15, 2023, except an extension can be granted until October 15, 2024, if the impoundment qualifies as an "eligible unlined CCR surface impoundment" as defined by the rule. 40 CFR § 257.103(f)(1)(vi). Regardless of the maximum time allowed under the rule, EPA explains in the preamble to the Part A rule that each impoundment "must still cease receipt of waste as soon as feasible, and may only have the amount of time [the owner/operator] can demonstrate is genuinely necessary." 85 Fed. Reg. at 53546.

Prior to *USWAG*, facilities that are not considered lined by the CCR Rule but are not impacting groundwater were not subject to closure, such as the impoundment at Spurlock Station. To mitigate from this harsh outcome for sufficiently protective lined CCR Units, EPA made further revisions, promulgating *Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments* (Closure Part B) on November 12, 2020. 85 Fed. Reg. 72506 (Nov. 12, 2020). The Closure Part B Rule finalized a process for unlined impoundments to operate with an alternate liner approved by EPA or a Participating State Director as part of an Alternate Liner Demonstration ("ALD"). *Id*. Specifically, owners and operators of a CCR surface impoundment may submit an ALD to the Administrator or the Participating State Director to demonstrate that, based on the construction of the unit and surrounding site conditions, there is no reasonable probability that continued operation of the surface impoundment will result in adverse effects to human health or the environment. 85 Fed. Reg. at 72539-42 (adding 40 CFR § 257.71(d)). To make this demonstration, applications were due on November 30, 2020, although the effective date of the Closure Part B Rule is December 14, 2020. If the application is approved, facilities perform field work and analysis to prepare a comprehensive final ALD package no later than November 30, 2021. The Biden Administration has listed both the Closure Part A and Closure Part B rules for reconsideration.

The EKPC facilities are in compliance with the CCR Rule. Spurlock Station has three regulated CCR units (1 surface impoundment and 2 landfills); Cooper Station has a regulated CCR unit (landfill); and Smith Station has a regulated CCR unit (landfill). The Dale Station ash ponds are not subject to the CCR Rule because the facility did not generate electricity after October 19,

2015. The ponds have been closed by removal in accordance with a closure plan approved by the Kentucky Division of Waste Management. Therefore, the Spurlock surface impoundment is EKPC's only surface impoundment regulated by the CCR Rule.

EKPC's CCR units are presently in detection monitoring, except for the Spurlock Station surface impoundment, which is in assessment monitoring. None of the constituents in the CCR units have been detected at statistically significant levels above the groundwater protection standards established under the CCR rule. Therefore, no corrective action is required. However, the Spurlock surface impoundment is unlined per the CCR Rule. The Final Closure Part A Rule dictates that EKPC cease placement of CCR material in the impoundment by April 11, 2021 due solely to the lack of a compliant liner.

EKPC has proactively pursued a CCR compliance plan, which has been under development for more than three years. In 2018, EKPC obtained approval by the Public Service Commission for its Clean Closure Plan to close the Spurlock Station surface impoundment by removal. To achieve this clean closure, the Wastewater Treatment Project will divert the handling of certain CCR streams away from the impoundment and, instead, to solids clarification, evaporation, and finally to a permitted CCR landfill. EKPC estimates that the Wastewater Treatment Project will be complete by 2023, the timing depending on a number of factors, such as construction timing, equipment availability, and weather. EKPC has no other alternative capacity options for CCR storage in the interim. EKPC has applied for an extension pursuant to the Closure Part A Rule. EKPC timely submitted its extension request by November 20, 2020. EKPC's bottom ash and fly ash flows can be rerouted prior to April 11, 2021, but EKPC requires an extension for other CCR and non-CCR flows until November 30, 2022. Fifty-seven (57) facilities requested an extension past April 11, 2021. Of the fifty-seven (57) applications submitted, EPA determined that four applications were incomplete, one application is ineligible and the rest are complete. EPA issued four decisions on the complete applications, including three proposed denials, and one proposed conditional approval for EKPC H.L. Spurlock Station. The remaining applications were deemed complete but will come at a later date post closure of the commentary period February 23, 2022. EKPC and three other facilities requested a 60-day extension. EPA granted a 30-day extension to the public commentary period that effectively closes March 25, 2022. Due to early planning and execution, EKPC has placed itself in a favorable compliance position by pursuing its CCR compliance strategy before many of its utility counterparts.

9.2 Future Compliance

As noted in Section 2.0, EKPC has identified the following future rules listed below from the EPA and Whitehouse Unified Agenda pending further action by the United States Executive Branch, Office of Management Budgets ("OMB") and the federal Environmental Protection Agency ("EPA"). The following future rules could have a material impact to the generation and transmission assets but the rules have not been publicized nor have they appeared in the federal registry. Therefore, EKPC is not in compliance nor is it required to comply with the following future rules just yet.

Particulate Matter NAAQS Updates

Proposed Rule: August 2022 **Final Rule: Expected March 2023**

EPA has begun to reconsider the Trump EPA's final rule to retain the national ambient air quality standard ("NAAQS") for fine particulate matter (PM2.5). Notably, EPA staff is recommending in the supplemental science assessment to tighten the annual $PM_{2.5}$ standard and is examining lowering the $PM_{2.5}$ standard from 12 $\mu g/m^3$ to 11 or even 10 $\mu g/m^3$. EPA's review of the $PM_{2.5}$

standard is scheduled to be completed by Spring 2023. If EPA decides to tighten the $PM_{2.5}$ annual NAAQS (as most expect), this more stringent standard will require further source-specific SO_2 and NO_x emission controls from coal-fired power plants and other major stationary sources of these two air pollutants. These additional controls could be imposed by states for addressing local nonattainment problems through state implementation plans ("SIPs") or by EPA in order to address downwind nonattainment problems in other states through a new federal interstate transport rule. A change in the $PM_{2.5}$ NAAQS will create many additional non-attainment areas. Additionally, EKPC plants (coal-fired power plants specifically) may not meet the lower NAAQS standards. State agencies may require modeling to show compliance or EKPC facilities may be modeled by others and noncompliance may be shown.

Source: Unified Agenda, RIN 2060-AV52,

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV52

Ozone NAAQS Updates

Proposed Rule: December 2023 **Final Rule: EPA TBD**

EPA announced its decision to conduct an expedited review of the Trump's decision not to tighten the ozone NAAQS. EPA will fast track the review of the ozone NAAQS by supplementing the formal Trump EPA rulemaking review with analysis of additional scientific studies and thereby complete its review by December 2023 instead of taking the full five years. Based on initial reports, the ozone standard could be tightened from 70 parts per billion ("ppb") to 65 or 60 ppb. Such a tightening of the ozone standard would likely result in the imposition of addition SIP control measures from major sources of NOx emissions, including coal-fired power plants, in order to achieve the more stringent ozone NAAQS in many parts of the country. These additional NOx emissions controls could be imposed by states for addressing local nonattainment problems through SIP control measures or by EPA in order to address downwind nonattainment problems in other states through a new federal interstate transport rule. A change in the ozone NAAQS would create many additional non-attainment areas.

Source: Unified Agenda, RIN: 2060-AV33

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV33

Social Cost of Carbon

Proposed Rule: August 2022 **Final Rule: Expected March 2023**

The White House has established an interagency working group that will establish new metrics for the social cost of carbon ("SCC"). As a general matter, EPA and other federal agencies are using the SCC as a benchmark for estimating the damages associated with incremental increases in Greenhouse Gas ("GHG") emissions and the benefits of reducing GHG emissions under regulatory programs. CO2 abatement costs below the SCC benchmark could thereby be used to justify the imposition of those control requirements under that particular regulatory program. The Biden administration has increased the SCC metric from $8 to $51 per ton of CO2 as the new "interim" value for the SCC. This SCC value is likely to increase further – most likely to a value substantially over $100 per ton of CO2 – once the Biden administration completes its re-assessment of the SCC metric sometime in 2022. The SCC will be instrumental in the development of the ACE Rule replacement. The SCC will determine the cost of controls that may be justified under the proposed rule so the higher the SCC, the more cost of control that may be justified.

Source: Technical Support Document, https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Mercury and Air Toxics Standards (MATS or NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units)

Notice of Proposed Rulemaking: June 2022 **Final Rule: Expected mid-2024**

On January 31, 2022, EPA issued a proposed rule to undertake several regulatory actions under the Mercury and Air Toxics Standards ("MATS") rule. The first change is to reinstate some language that was removed but has no practical effect on coal utilities since the MATS emissions limitations for coal-fired power plants were maintained in the MATS rule, and these sources have already complied with the MATS rule.

The second change includes an EPA request for the submission of additional information on new technologies, techniques, and measure that could justify tightening the current MATS limitations in the future. This information request effectively opens the door for EPA to tighten the current MATS limitations. EPA could attempt to justify the adoption of those tighter HAP limitations based on additional technical and cost information on controlling HAP emissions from coal-fired power plants along with the new information that EPA has just now developed on the health benefits of controlling HAPs emission under the MATS rule. The tightening of the MATS limitations could have major regulatory impacts on a significant portion of the coal fleet. Since this regulatory effort would require EPA to initiate an entirely new notice and comment rulemaking, the promulgation of a final rule by EPA to tighten the MATS limitations under an updated technology review would most likely not occur until sometime in 2024.

Additionally, the regulatory agenda for the EPA describes that the Agency will issue the MATS rule pursuant to section 610 of the Regulatory Flexibility Act (5 U.S.C. 610) to determine if the provisions that could affect small entities should be continued without change or should be rescinded or amended to minimize adverse economic impacts on small entities. As part of this review, EPA is considering comments on: 1) The continued need for the rule; 2) the nature of complaints or comments received concerning the rule; 3) the complexity of the rule; 4) the extent to which the rule overlaps, duplicates, or conflicts with other Federal, State, or local government rules; and 5) the degree to which the technology, economic conditions or other factors have changed in the area affected by the rule.
Source: Unified Agenda, RIN: 2060-AV12, 2060-AV53, 2060-AV08,
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV12
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV53
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV08

Cross-State Air Pollution Rule (CSAPR) 3.0 implementing 2015 Ozone NAAQs

Proposed Rule: Expected February 28, 2022 Final Rule: Expected December 15, 2022

EPA issued in March 2021 a revised Cross-State Air Pollution Rule ("CSAPR") that imposed a more stringent set of NOx control requirements for fossil-fueled power plants located in 12 states in the eastern half of the United States. The EPA is now shifting its focus to the development of an ozone interstate transport for meeting the 2015 NAAQs standard. Although still in the early stages, this transport rule is expected to impact the electric power sector (including coal-fired power plants) in two ways. First, it could require the installation of NOx SCR control systems on any remaining coal-fired power plants without these state-of-the-art controls. Second, it could require additional NOx reduction on those coal-fired power plants with SCR control systems by requiring enhanced catalysts and performance optimizations of these existing SCR control systems.

Source: Unified Agenda, RIN 2060-AS74,

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AS74

https://www.epa.gov/csapr/nox-ozone-season-group-3-trading-program-under-revised-cross-state-air-pollution-rule-csapr

https://www.epa.gov/sites/default/files/2021-03/documents/revised_csapr_update_factsheet_for_final_rule.pdf

Replacement of the ACE Rule

Notice of Proposed Rulemaking: Expected July 2022 Final Rule: Expected July 2023

EPA has an obligation to adopt a new rule that would set performance standards to limit CO_2 emissions from existing fossil-fueled power plants under section 111(d) of the CAA. This new rule will replace the Affordable Clean Energy ("ACE") rule that the D.C. Circuit invalidated last January along with the Clean Power Plan ("CPP") rule that EPA repealed during the Trump Administration. The rulemaking schedule for EPA's development of an ACE replacement rule is uncertain at this time although the most recent unified regulatory agenda indicates that a proposed rule is expected by July 2022 and a final rule by July 2023. Uncertainty also exists on the framework of stringency of any future replacement rule that EPA may adopt. Further clarity on these important substantive rulemaking matters will largely be addressed by the Supreme Court in the pending ACE/CPP litigation. In particular, the Supreme Court will likely rule on the extent of EPA's authority to regulate CO_2 emissions from coal-fired power plants under section 111(d) of the CAA – specifically, whether EPA has authority to set CO2 performance standards based on "beyond the fence control measures," such as generation shifting from coal-fired to renewable energy generation.

Source: Unified Agenda, RIN: 2060-AV10

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV10

https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-advance-notice-proposed

Electric Generating Unit GHG New Source Performance Standard

Notice of Proposed Rulemaking: Expected June 2022 Final Rule: Expected June 2023

On October 23, 2015, the EPA finalized Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, found at 40 CFR Part 60, subpart TTTT. On December 20, 2018, the EPA proposed to revise the standards of performance in 40 CFR Part 60, subpart TTTT. The EPA proposed to amend the previous determination that the best system of emission reduction (BSER) for newly constructed coal-fired steam generating units (i.e., EGUs) is partial carbon capture and storage, and replace it with a determination that BSER for this source category is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices. The EPA is undertaking a comprehensive review of the NSPS for greenhouse gas emissions from EGUs, including a review of all aspects of the 2018 proposed amendments and requirements in the 2015 Rule that the Agency did not propose to amend in the 2018 proposal. More to come in 2022.

Source: Unified Agenda, RIN 2060-AV09 and 2060-AV10

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV09

Emissions Monitoring and Reporting Requirements for Fossil EGUs

Notice of Proposed Rulemaking: Expected July 2022 Final Rule: Expected after July 2022

On January 19, 2021, the D.C. Circuit Court issued an opinion vacating the Affordable Clean Energy Rule (found at 40 CFR part 60, subpart UUUUa) – the previously applicable emission guidelines for GHG emissions from existing electric generating units ("EGUs"). The EPA is working on a new set of emission guidelines for states to follow in submitting state plans to establish and implement standards of performance for greenhouse gas emissions from existing fossil fuel-fired EGUs.

PSD and NNSR: Reconsideration of Fugitive Emissions Rule

Notice of Proposed Rulemaking: Scheduled June 2022 Final Rule: TBD

The EPA is reconsidering the final rule titled "Prevention of Significant Deterioration ("PSD") and Nonattainment New Source Review ("NSR"): Reconsideration of Inclusion of Fugitive

Emissions; Reconsideration." Through a letter signed on April 24, 2009, the EPA granted reconsideration on a petition submitted by the Nation Resources Defense Council ("NRDC"), as well as an administrative stay of the Fugitive Emissions Rule provisions. On March 30, 2011, the EPA issued an interim rule that stayed the Fugitive Emissions Rule by reverting the text of the affected sections of the Code of Federal Regulations back to the prior rule language. This stay will remain in effect until the EPA completes its reconsideration and undertakes any associated rulemaking. The final fugitive emissions rule required fugitive emissions to be included in determining whether a physical or operational change results in a major modification only for sources in industries that have been designated as major.

Source: Unified Agenda, RIN 2060

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AQ47

https://www.epa.gov/sites/default/files/2015-12/documents/20100204stayfs.pdf)

Regional Haze

States Submit Plans: 07/31/2021 **Final Rule: TBD**

States have an obligation to develop and submit their regional haze plans for addressing visibility impairment in Class I areas during the second implementation period. On July 8, 2021, EPA issued guidance that attempts to limit the broad discretion and flexibility that states have in the development of their regional haze plans. Similarly, the EPA regions also have begun to take narrow interpretation of states' discretion in how they achieve their reasonable progress goals when reviewing states' regional haze plans for the second planning period. The intended overall effect of this new interpretation is to require the installation of SO_2 scrubbers and NO_x SCR control systems on the last remaining coal-fired power plants that are not currently operating with those SO_2 and NO_x control systems. Although the deadline for state submitting their regional haze plans was July 31, 2021, most states, including Kentucky, are still in the process of developing their plans and will not be ready to submit their plans until sometime later this year.

Source: https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf

Regulation of Coal Combustion Residuals

On July 9, 2021, EPA announced that it plans to implement several of Trump EPA rules for the regulations of coal combustion residuals ("CCR") without any changes in the current regulations. According to the Agency, no changes are necessary based on its determination that current CCR regulations provide "the most environmentally protective course of action." Although EPA will not be initiating a rulemaking to reconsider the current rules on the mandatory closure of existing unlined surface impoundments, EPA has initiated an effort to impose a new rigorous and overly prescriptive interpretation of the current federal CCR requirements on coal-fired power plants. This is reflected by EPA's proposed decisions not to approve many of the closure extension requests based on the coal-fired electric utilities' failure to comply with the applicable CCR requirements, as now being interpreted by the EPA. Spurlock has received a proposed conditional approval and will continue compliance efforts in accordance with that proposal. The overall purpose and effect of EPA's CCR initiative is to increase the stringency of the closure and remediation requirements and, in many cases to require the removal of the CCR from existing unlined impoundments (which EKPC is already doing). Finally, EPA has underway several other rulemakings that will establish new federal CCR requirements regarding permitting, legacy surface impoundments, and beneficial use of CCR products. All of these new requirements could increase stringency of the current federal CCR requirements on the management and disposal of CCR material by coal-fired electric utilities.

Source: Unified Agenda, RIN: 2050-AH14 and 2050-AH18

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2050-AH14

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2050-AH18

CCR Holistic Part A

Proposed Rule: **Final Rule: 8/28/2020**

Deadline to Initiate Closure and Enhanced Public Access to Web information went final July 29, 2020. Revised date for closure is April 11, 2021 unless extension is granted by EPA. EKPC submitted a Demonstration to EPA on November 30, 2020 in support of a request for an extension of the deadline to initiate closure of the Spurlock Impoundment until November 30, 2022. On January 11, 2022, EPA issued a proposed decision to approve EKPC's request with conditions. EKPC must submit a response to EPA's proposed decision by March 25, 2022. If the request is ultimately denied, EKPC would be required to cease all waste streams to the Spurlock Impoundment and initiate closure within 135 days of EPA's final decision.

CCR Holistic Part B

Proposed Rule: 03/03/2020 **Final Rule: 12/14/2020**

Alternative Demonstration for unlined surface impoundments and implementation of closure was proposed in federal register on March 03, 2020. It allows our Industry to use procedures to line ponds, two co-proposed options to close ponds, removal or in place with a cap, and requirements for annual progress reports. Pre-publication copy appeared in the federal register on October 15, 2020 that is under internal review. Had little to no impact to EKPC.

2020 Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

Proposed Rule: **Final Rule: 12/14/2020**

EPA is reconsidering the 2020 reconsideration rule and evaluating the technologies available to the industry for FGD wastewater treatment, bottom ash transport water (specifically purge water), landfill leachate, and legacy wastewater, among other waste streams. EKPC (specifically at Spurlock) has already implemented projects to eliminate bottom ash transport water and provide for zero discharge of FGD wastewater (other than a potential intermittent high-quality distillate stream). Depending on the outcome of EPA's review (expected rulemaking in Q4 2022), additional limits may be added on other waste streams that could require treatment solutions or additional monitoring at the remaining coal units.

Regulation of CO_2 as a Criteria Air Pollutant through the SIP process

Proposed Rule: TBD- Longterm Review **Final Rule: TBD- Longterm Review**

EPA announced in March 2021 its withdrawal of the Trump EPA's denial of a petition by the Center for Biological Diversity to set a NAAQS for CO_2 under the CAA. If EPA were to adopt a NAAQS for CO_2, each state would then be required to adopt climate change SIP that would regulate all major sources of CO_2 (including coal-fired power plants) within its jurisdiction. If any state fails to adopt and implement a SIP in a timely fashion, EPA then has the authority and responsibility to adopt a federal implementation plan for regulating CO_2 emissions from power plants and other sources within the state. The EPA has not made the threshold decision on whether to regulate CO_2 as a criteria pollutant under the CAA, let alone set any timeline for doing so.

Regulation of GHGs as International Air Pollution

Proposed Rule: TBD- Longterm Review **Final Rule: TBD- Longterm Review**

EPA is reportedly examining its authority to regulate GHG emissions as "international pollution" under section 115 of the CAA. EPA has the authority to require states to regulate GHG emissions within their jurisdiction upon making the following two findings: (1) GHG emissions from any state "may reasonably be anticipated to endanger public health or welfare in a foreign country;" and (2) the foreign country being impacted by the GHG emissions "has given the United States essentially the same rights with respect to the prevention or control of air pollution occurring in that country as is given that country by [section 115]." Although in existence since 1977, this provision has been only used twice for regulating emissions causing acid rain pollution prior to the enactment of 1990 CAA amendments. The EPA has not made the threshold decision on whether to initiate a rulemaking to regulate GHG emissions under CAA section 115, let alone set any timeline for doing so.

Source: EPA Regulations Impacting the Coal Fleet Feb 7 2022.pdf.

Implementation of the 2008 NAAQS for Ozone: SIP Requirements Update

Proposed Rule: **Final Rule: CSAPR 2.0 March 2021**

This proposed rulemaking would update the final State Implementation Plan ("SIP") Requirements Rule for the 2008 Ozone NAAQS (80 FR 12264, March 6, 2015) to reconcile regulatory provisions that were vacated as part of the decision in South Coast Air Quality Management District v. EPA, 882 F.3d 1138 (D.C. Cir. 2018) (South Coast II) with those listed in part 51 of the Code of Federal Regulations. The 2008 SIP Requirements Rule governs attainment planning requirements that apply to areas designated nonattainment for the 2008 ozone NAAQS, and states in the Ozone Transport Region, as well as anti-backsliding requirements for areas once designated nonattainment for the revoked ozone NAAQS. This proposed action would clarify national policy by updating affected provisions in the 2008 ozone SIP Requirements Rule to reflect the outcome of South Coast II and ensure that states understand the requirements that apply to them for continued implementation of the ozone NAAQS.

Source: Unified Agenda, RIN: 2060-AU88

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AU88

Reclassification of Major Sources as Area Sources Under Section 112 of the Clean Air Act

Proposed Rule: Expected June 2022 **Final Rule: Scheduled June 2023**

The Reclassification of Major Sources as Area Sources Under section 112 of the Clean Air Act (Major MACT to Area-MM2A final rule) was promulgated on November 19, 2020, and became effective on January 19, 2021. This rule provides that a major source can be reclassified to area source status at any time upon reducing to its potential to emit ("PTE") hazardous air pollutants ("HAPs") to below the major source thresholds of 10 tons per year of any single HAP and 25 tpy of any combination of HAP. On January 20, 2021, President Biden issued Executive Order 13990 "Protecting Public Health and the Environment and Restoring Science to Take the Climate Crisis." The EPA has identified the MM2A final rule as an action being considered pursuant to section (2)(a) of Executive Order 13990. Under this review, EPA will publish for comment a notice of proposed rulemaking either suspending, revising, or rescinding the MM2A final rule.

Source: Unified Agenda, RIN: 2060-AV20

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV20

Petition to Delist Stationary Combustion Turbines From the List of Categories of Major Sources of Hazardous Air Pollutants

Proposed Rule: Expected April 2022 **Final Rule: TBD**

The Clean Air Act section 112(c)(9) requires EPA to consider petitions to add or remove source categories. EPA reviews a petition to determine whether it provides adequate data and can be determined complete. If EPA decides that information is not adequate, the Administrator may use any authority available to him to acquire such information. Once the petition is determined to be complete, EPA must, within 12 months from the last receipt of information from the petitioners, either grant or deny the petition. On August 28, 2019, EPA received a petition to remove the Stationary Combustion Turbines source category from the list of categories of major sources. On November 19, 2019, December 2, 2020, and March 15, 2021, EPA received supplements to the petition. The EPA is currently evaluating the petition for completeness and will issue a notice to notify the petitioners and the public of its determination of whether the petition will be granted (a proposed rule making) or denied.

Source: Unified Agenda, RIN: 2060-AU78
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AU78

New Source Review

Proposed Rule: **Final Draft: 11/24/2020**
Final Guidance/Memorandum

August 5, 2020 - EPA issued NSR guidance on August 5, 2020 to help Industry use plant wide applicability limitations ("PALs") as a path forward in permitting projects as minor NSR projects. Unfortunately, PALs must be renewed and risk termination. PALs offer some possibilities but present risk.

Draft Guidance
March 25, 2020 issued draft guidance to help industry and its regulators interpret and understand pre-construction and construction penalties under this program.

December 2, 2019 – EPA issued ambient air guidance to the Industry and States. Thus, the EPA's revised ambient air policy, consistent with its discretion available under the regulatory definition of ambient air, is that the atmosphere over land owned or controlled by the stationary source may be excluded from ambient air where the source employs measures, which may include physical barriers, that are effective in precluding access to the land by the general public.

EPA Proposed Action on "Project Emissions Accounting" occurred on August 1, 2019. EPA proposed to clarify the process for evaluating whether the NSR permitting program would apply to proposed projects at existing air pollution sources. This proposal would make it clear that both emissions increases and decreases from a major modification at an existing source are to be considered during Step 1 of the two-step NSR applicability test. This process is known as project emissions accounting (previously referred to as project netting.)

EKPC is advocating using the hourly maximum emissions from a source as the baseline by which NSR going forward should use to incorporate efficiencies gained under the Affordable CleanEnergy Rule. Thus, NSR would not prevent the Industry from performing efficiency projects that may result in enforcement action under the current NSR policy for title V of Clean Air Act and PSD.

WOTUS

Proposed Rule: December 7, 2021 **Final Rule: TBD, Anticipated in 2023**

EPA and the Army Corps of Engineers have initiated proposed rulemaking to again revise the definition of waters of the United States. EPA notes there will be two phases to the rulemaking. The first phase, for which a proposed rule was published in the Federal Register on December 7, 2021, would restore the pre-2015 definition of WOTUS, "updated to reflect consideration of Supreme Court decisions." The public comment period on that proposed rule closed on February 7, 2022. The date of a final rule is uncertain but may be sometime in late 2022. The second phase, for which a proposed rule is expected sometime in 2022, would make further revisions to the definition based on input from states, tribes, local governments, and a broad array of stakeholders. On February 24, 2022, EPA announced the selection of ten geographically varied roundtables to facilitate discussion on implementation of the WOTUS rule, to be conducted virtually over the Spring and Summer 2022. The date of a proposed or final rule on the second phase of rulemaking is uncertain but a final rule is not anticipated until 2023. [RIN: 2040-AG13 and RIN: 2040-AG19].

These rulemaking actions followed a federal court decision on August 30, 2021 which vacated the January 2020 revisions to the definition of WOTUS (which had significantly reduced the scope of federal jurisdiction). On January 24, 2022, the US Supreme Court announced it would review a lower court ruling (*Sackett v. EPA*, 9th Circuit) that applied the definition of WOTUS established in the 2006 Supreme Court case, *Rapanos v. United States*. This review may resolve ambiguities in the definition of WOTUS and the extent of federal laws and permitting authority by giving the Supreme Court an opportunity to revisit its *Rapanos* decision.

NEPA

Phase 2 Proposed Rule: June 2022 **Final Rule: TBD**

Council on Environmental Quality ("CEQ") – CEQ published a Notice of Proposed Rulemaking on October 7, 2021 to modify regulations for implementing the procedural provisions of the National Environmental Policy Act ("NEPA") to "generally restore regulatory provisions that were in effect for decades before being modified in 2020". The proposed rule would "restore provisions addressing the purpose and need of a proposed action, agency NEPA procedures for implementing CEQ's NEPA regulations, and the definition of 'effects'". The public comment period closed on November 22, 2021 and review continues for a final rulemaking in 2022. [RIN: 0331-AA07]

USACE Implementing Regulations

Proposed Rule: Anticipated September 2023 **Final Rule: TBD**

NEPA – Following final actions by CEQ, the Corps will propose to update the NEPA implementing procedures applicable to all of the Corps' Regulatory and Civil Works Programs. [RIN: 0710-AB20]

Dept. of Interior, Fish & Wildlife Service

Proposed Rule: TBD **Final Rule: TBD**

Monarch Butterfly Status - On December 17, 2020, the U.S. Fish and Wildlife Service ("USFWS") completed its 12-month finding on the petition to list the monarch butterfly under the Endangered Species Act ("ESA"). It determined that listing the monarch under the ESA is warranted but precluded at this time by higher-priority listing actions. As a part of this finding, it determined that an emergency listing was not necessary because of ongoing conservation measures. Although USFWS has stated a 2024 timeframe for the monarch, the agency may choose to make significant progress on its listing backlog and, hence, expedite the listing of the monarch. This listing may have implications for EKPC in its land management activities in right-of-way corridors (e.g., use of herbicides, invasive species control, brush and tree management, mowing, and revegetation), substations, and development projects. [RIN: 1018-BE30]

Proposed Rule: Anticipated September 2022 Final Rule: TBD

Northern Long-eared Bat – On March 1, 2021 the U.S. District Court for the District of Columbia issued an order directing the USFWS to issue a new listing determination under the ESA for the northern long-eared bat ("NLEB") by a date certain. The USFWS must issue a new proposed rule and final listing decision within 18 months of completing the joint Species Status Assessment ("SSA") for the NLEB, tri-colored bat, and little brown bat (each has a broad, multi-state range). Potentially affects development and maintenance of transmission corridors. [RIN: 1018-BG14]

Migratory Bird Treaty Act

Proposed Rule: May 6, 2021 Final Rule: Anticipated April 2022

The USFWS published a proposed rule to revoke the Trump-era final rule that codified the Migratory Bird Treaty Act ("MBTA") does not prohibit incidental take. The USFWS will return to implementing the MBTA as prohibiting incidental take and applying enforcement discretion. USFWS is proposing three options for its proposed permitting program: individual permits, general permits, and permit exclusions. It appears USFWS favors a general permitting structure. [RIN: 1018-BD76]

CWA Effluent Limitation Guidelines

Proposed Rule: Anticipated Fall 2022 Final Rule: TBD

Effluent Limitations Guidelines ("ELGs") – Following its review of the 2020 Steam Electric Reconsideration Rule, EPA has initiated a supplemental rulemaking for certain discharge limits in the Steam Electric Power Generating category (40 CFR Part 423). Several of the limits under review may result in more stringent limits and potentially impact EKPC's current efforts to comply with the 2015 and 2020 rules. As part of this supplemental rulemaking, EKPC received a Clean Water Act ("CWA") Section 308 information request letter on January 7, 2022 with an extensive list of items that to be submitted to EPA no later than February 20, 2022. EKPC is working diligently to respond to the request and has received a 60-day extension from EPA (until April 21, 2022) to submit. Notice of Proposed Rulemaking Initiative published August 3, 2021. [RIN: 2040-AG11]

Proposed Rule: Anticipated September 2022 **Final Rule: TBD**

EPA/State 401 Certification - EPA revised the 401 regulations, entitled "Clean Water Act section 401 Certification Rule", in June 2020 which among other things included limits on the timing and scope of state 401 certifications of federally licensed or permitted projects. EPA has completed its review of the June 2020 regulation and determined that it will propose revisions to the rule through a new rulemaking effort. NPRM anticipated March 2022. [RIN: 2040-A G12]

USACE Implementing Regulations

Proposed Rule: TBD **Final Rule: TBD**

401 Certification – In response to any forthcoming final EPA water quality certification regulation, the Corps would propose to amend its regulations for the Regulatory Program to ensure consistency with that EPA rule. [RIN: 0710-AB21]

KDOW Triennial Review of Water Quality Standards

Proposed Rule: Anticipated August 2022 **Final Rule: Anticipated Summer 2023**

KDOW is currently undertaking the triennial review of its water quality standards (WQS) mandated by Congress. Changes made in the WQS will ultimately be included in EKPC's discharge permits. The review includes public participation, which KDOW began with a public listening session in June 2021. Public notice of proposed changes to the WQS is tentatively scheduled for August 2022, with a public hearing in September. Following administrative review, KDOW will submit its proposed revisions for EPA approval in mid-2023.

SECTION 10.0

FINANCIAL PLANNING

SECTION 10.0

FINANCIAL PLANNING

807 KAR 5:058 Section 9(1-4). The integrated resource plan shall, at a minimum, include and discuss the following financial information: (1) Present (base year) value of revenue requirements stated in dollar terms; (2) Discount rate used in present value calculations; (3) Nominal and real revenue requirements by year; and (4) Average system rates (revenues per kilowatt hour) by year.

Table 10-1 provides the Present (base year) value of revenue requirements stated in dollar terms for the 2022 IRP and the Nominal and Real Revenue Requirements (in $millions) from the owner-members. The Average Rate for each of the forecasted years included in the plan is defined as the Nominal Revenue Requirements divided by the total Sales to Members (in cents/kWh) and is also included in Table 10-1 below.

The discount rate used in present value calculations is the weighted average cost of EKPC's outstanding long-term debt as of February 28, 2022 multiplied by a 1.50 TIER.

TABLE 10-1
EAST KENTUCKY POWER COOPERATIVE, INC.
REVENUE REQUIREMENTS AND AVERAGE SYSTEM RATES

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2022$ * ($000)	Total From Members Present Value ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2022$*
2022	[redacted]					
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
2036						

** PV = [redacted]

* Assumes an annual inflation rate of [redacted]

** Present value of revenue requirements using EKPC's discount rate of

SECTION 11.0

SYSTEM MAP

SECTION 11.0

SYSTEM MAP

807 KAR 5:058 Section 8.(3)(a) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

Please see system map on the following page.

System Map

Confidential protection of the system map has been requested in the form of a motion for confidential treatment.

EXHIBIT ACL-8

South Carolina Market Reform Report

Assessment of Potential Market Reforms for South Carolina's Electricity Sector

FINAL REPORT TO THE ELECTRICITY MARKET REFORM MEASURES STUDY COMMITTEE OF THE SOUTH CAROLINA GENERAL ASSEMBLY

PREPARED BY

John H. Tsoukalis
Kathleen Spees
Johannes P. Pfeifenberger
Andrew Levitt
Andrew W. Thompson
Oleksandr Kuzura
Evan Bennett
Son Phan
Megan Diehl
Ellery Curtis
Sylvia Tang
Ryan Nelson

PREPARED FOR

South Carolina General Assembly

APRIL 27, 2023

Brattle

NOTICE

This study has been funded by the South Carolina State General Assembly under the Electricity Market Reform Measures Study Committee and has been informed by data and input provided through a thirteen-month process. Throughout the course of this study, Brattle consultants conducted several engagement sessions with the Study Committee composed of members of the South Carolina Senate and House as well as the Advisory Board comprised of a wide range of stakeholders in South Carolina's energy industry. For a complete timeline of events and list of Study Committee and Advisory Board members and their affiliations, see Appendix D.

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Executive Summary

In accordance with the requirements of Act 187, the South Carolina Electricity Market Reform Measures Study Committee ("Study Committee") has commissioned this independent assessment to examine the potential benefits of introducing market reforms to South Carolina's electricity sector. Over a period of thirteen months beginning March 2022, we have worked in close coordination with the Study Committee and the Advisory Board of stakeholder representatives to assess the status of South Carolina's electricity sector, answer questions posed by state legislators, refine the study scope, and develop primary study assumptions with input from the Advisory Board. We present in this report our independent findings with respect to the benefits of introducing various market reforms to South Carolina's electricity sector.

At present, South Carolina's electricity sector is structured under a vertically integrated utility model, with approximately 61% of all energy demand served by three large investor-owned utilities: Duke Energy Progress and Duke Energy Carolinas (collectively "Duke"), and Dominion Energy South Carolina ("Dominion").[1] Each of these utilities is granted the exclusive right to provide electricity supply to retail customers within their service territories, subject to regulatory oversight from the South Carolina Public Service Commission (PSC). The remaining 39% of South Carolina energy demand is served by the large state-owned utility South Carolina Public Service Authority ("Santee Cooper"), 20 member-owned electric cooperative utilities, and 7 municipally owned utilities.[2]

1 These utilities serve 7% (Duke Progress), 26% (Duke Energy Carolinas), and 27% (Dominion) of South Carolina energy demand. In addition to their role as vertically integrated utilities and distribution providers, these entities (and the state-owned utility Santee Cooper) also act as the Balancing Authorities that manage real-time energy balance on the system within their bulk transmission system areas, and provide energy supply to municipal and cooperative utilities. In their roles as Balancing Authorities, these same companies support energy deliveries to 8% (Duke Progress), 34% (Duke Energy Carolinas), 28% (Dominion), and 30% (Santee Cooper) of South Carolina's customers. For the purposes of this study, we will discuss the role of these entities both as Balancing Authorities (collectively, the four companies serve all South Carolina customers in this role) and as vertically integrated utilities (31 separate utility companies serve South Carolina customers in this latter role, under a range of ownership structures and business models). Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021 data.

2 Santee Cooper directly serves 12% of South Carolina customers, and indirectly serves the majority of energy supply needs to South Carolina's cooperative utilities through a supply contract with Central Electric Power Cooperative (a company that is in turn owned by 20 member cooperatives that act as the distribution utilities serving end use customers and 23% of South Carolina's total energy demand). Municipal utilities serve the

In this study, we examine the nature and size of potential benefits that could be achieved by market reforms in the electricity sector. We structure our assessment of the potential benefits across three areas of reform:

- **Wholesale market reforms** that could improve the cost-effectiveness of generation resource operations and trade across regions;
- **Resource planning and competitive investment reforms** that seek to improve the cost-effectiveness of resource investment decisions, some of which can also shift investment risks from customers to generator owners; and
- **Retail market reforms** that would offer customers greater opportunities to select their preferred resource mix or rate structure, including possibly from multiple competitive retail suppliers.

We find that South Carolina ratepayers stand to gain substantial benefits from a measured introduction of enhanced regional coordination and market reforms in all three of the above categories. These benefits can be achieved most reliably through incremental reforms that follow best practice in the sequencing and introduction of various reforms. Doing so will maximize consumer benefits and manage transition risks considering South Carolina's unique circumstances and industry structure.

remaining 4% of South Carolina's energy customers. Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, for year 2021 and Central Electric Power Cooperative, Inc., Integrated Resource Plan 2021–2040, 2020.

WHOLESALE MARKET REFORMS

Today, South Carolina's utilities are responsible for scheduling generation within their service territories. These utilities forecast their electricity demand, determine what generating facilities to turn on or off on a daily, hourly, and sub-hourly basis, schedule power deliveries to customers, and engage in bilateral purchases and sales with neighboring utilities. The large utilities are additionally transmission operators and owners, and so must allow third parties to schedule power deliveries across their respective transmission systems under federal transmission "open access" laws. To support more cost-effective bilateral trades in the short-term spot market, the South Carolina utilities, along with other utilities in the Southeast, have introduced a new Southeast Energy Exchange Market (SEEM) that began operations on November 9, 2022 and facilitates non-firm bilateral transactions in 15-minute intervals.

To examine the potential benefits and costs of market reforms to the South Carolina utilities' wholesale market and transmission system operations, we have conducted a detailed assessment of several alternative wholesale market structures that are in use throughout the U.S. In order of increasing levels of wholesale market competition and expanded geographic scope, the wholesale market reform options we examined are:

- Retain the **Status Quo** with South and North Carolina (Carolinas) utilities operating generators to match their own customers' demand while trading power bilaterally including through the new SEEM;
- Implement a Carolinas-wide **Joint Dispatch Agreement (JDA)** under which the Carolinas utilities would make arrangements to jointly coordinate and improve the dispatch efficiency of their generation (similar to the JDA Duke is currently using in its South Carolina and North Carolina service territories to increase dispatch efficiency across its two subsidiaries);

- Implement a **Southeast Energy Imbalance Market (EIM)** in which an independent third party fully optimizes the real-time dispatch of resources in the Carolinas and across the Southeast, a structure that is currently used in eleven states across the Western U.S. The EIM option can be supplemented with a regional resource adequacy framework;[3]
- Create a **Southeast Regional Transmission Organization (RTO)** with the same footprint as the hypothetical Southeast EIM above, but with additional functionality that includes day-ahead market operations, consolidated balancing areas with pooled reserves, a regional resource adequacy framework, and regional transmission service and planning; and
- Join or otherwise integrate with **PJM Interconnection (PJM) RTO**. This option offers the same functionality as the Southeast RTO, but with the Carolinas joining PJM (or otherwise integrating with PJM's wholesale power markets),[4] the existing neighboring RTO that presently covers utility areas across thirteen states and the District of Columbia (covering the Mid-Atlantic states from the northern portion of North Carolina to New Jersey and stretching west to Chicago).

[3] The new FERC-approved Western Resource Adequacy Program (WRAP) allows utility participants to take advantage of regional load diversity and the trading of well-defined capacity products. WRAP participation can be combined with participation in the CAISO-administered Western Energy Imbalance Market (WEIM), the SPP-administered Western Energy Imbalance Service (WEIS), and the SPP-administered "Markets+" and Western RTO options. See M. McNichol, "WPP Announces FERC Approval of WRAP Tariff," Western Power Pool, February 10, 2023; Western Power Pool, WRAP: Western Resource Adequacy Program, accessed February 1, 2023; and Southwest Power Pool, Western Energy Services, Markets + Webinar, November 17, 2021.

[4] In addition to fully joining PJM as a member, PJM may be able to accommodate wholesale market participation of South Carolina utilities in a non-RTO pooling arrangement, similar to the regional energy and resource adequacy market option offered by CAISO and SPP in the Western U.S.—such as EIM, EDAM, "Markets+" and "WRAP"—as discussed in more detail in the body of this report. Joining or otherwise integrating with PJM's wholesale power markets would not change the vertically-integrated and state-jurisdictional nature of South Carolina's utilities.

Table ES-1 summarizes the net benefits that we estimate would accrue to South Carolina customers under each of these wholesale market reforms, ranging from $1 million to $362 million per year. The benefits to South Carolina customers include cost savings accruing to customers in the Santee Cooper and Dominion balancing areas, plus a share of the cost savings accruing to customers in Duke's balancing areas based on the portion of load in Duke's BA located in South Carolina. These annual benefits accrue through operational and investment-cost savings, which likely will increase over time as load grows, fuel prices increase, and the generation mix changes over the years to include more renewable resources.

Operational savings arise both by allowing power to flow more freely across multiple utility areas in the larger geographic region (without having to book transmission at each utility boundary) and from the improved efficiency from coordinating day-ahead scheduling and real-time dispatch across greater geographic areas.

Investment cost savings in the RTO scenarios or in a coordinated resource adequacy framework over the same regions, arise from the ability to reduce the total amount of necessary generation investments due to the higher diversity of supply and demand in the greater geographic area in a regional RTO market.[5] Administrative costs arise from operation and implementation of the business processes that perform the coordinating functions.

TABLE ES-1: ANNUAL SOUTH CAROLINA CUSTOMER SAVINGS FROM WHOLESALE MARKET REFORMS (2022$ MILLIONS/YEAR, 2030 STUDY YEAR)

	Units	Operational Savings	Investment Cost Savings	Administrative Costs	Annual Net Benefits
Carolinas JDA	$ Mln/year	$10-$13	N/A[6]	$2 – $4	**$6-$11**
Southeast EIM	$ Mln/year	$22-$27	N/A[6]	$2 – $5	**$17-$25**
Southeast RTO	$ Mln/year	$87-$106	$94–$117	$36 – $66	**$115-$187**
Integrate w/ PJM	$ Mln/year	$163-$200	$158–$198	$36 – $40	**$281-$362**

Sources/Notes: Savings are those that South Carolina customers would accrue including reductions to operating costs (i.e., fuel costs, variable costs, cost of purchases, net of sales revenues), and reductions to investment costs (i.e., reductions to total capacity requirements due to load diversity). Values reported in 2022$.

5 This table does not account for the additional benefits that could be achieved if RTO participation is also used as a means to gain access to lower-cost capacity through competitive generation procurement or regional trade of capacity; those potential benefits are discussed in Table ES-3, Section III.E, and Appendix B.

6 Capacity investment benefits similar to those from RTO participation could also be enabled through the creation of a region-wide resource adequacy framework, such as the new Western Resource Adequacy Program (WRAP), as noted earlier.

The quantified operational savings are comparable to the results of similar studies in other parts of the country, where retrospective studies of RTO market benefits show operational savings in the 4%–8% range, with a portion of these savings achievable through a regional EIM (noting that a portion of regional coordination benefits are already accounted for in the status quo scenario through SEEM).[7] Our estimates of generation investment cost savings created through RTO participation (or alternative regional resource adequacy frameworks) are consistent with the experience of other states, such as in Louisiana, where Entergy was able to reduce its planning reserve margin from 18% to 12% due to regional load diversity by joining the Midcontinent ISO (MISO).[8] Entergy estimated that joining MISO would save the utility between $170 million and $225 million in power production costs and would save customers more than $1 billion for the 2013 to 2022 timeframe.

Our estimates of operational savings may be conservatively low due to various modeling assumptions and simplifications. Based on experience to date in other regions and due to the conservative nature of our estimates, we anticipate that the scale of economic and reliability benefits from participation in regional wholesale electricity markets will grow as the sector evolves to incorporate a growing share of variable renewable resources, demand response, batteries, and distributed resources.

In addition to the economic savings South Carolina customers would accrue, enhanced participation in regional wholesale power markets can offer other benefits, including increased volume of competitive energy transactions (i.e., higher liquidity) and transparency of market prices, a more diverse resource mix, enhanced support for bilateral contracting, and efficiencies unlocked by region-wide transmission planning. Immediately upon joining an RTO, South Carolina's cooperative member-owned and municipally owned utilities would enjoy greater

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7 The Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), July 8, 2016; J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020.; J. Chang, *et al.*, Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.; J. Chang, *et al.*, Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020.

8 Entergy, which owns approximately 24,000 MW of generation, anticipated that its generation capacity requirement would be 1,400 MW less (approximately 6% of peak load) as a MISO member than as a standalone entity, since its effective reserve margin would be 12% as a MISO member compared to 17%–20% as a standalone entity. MISO's subsequent analysis found that the MISO South region, which then included Entergy, achieved $560–$750 million in load diversity benefits. See Entergy, An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO, presented before the Public Utility Commission of Texas, May 12, 2011; and MISO, 2015 Value Proposition Stakeholder Review Meeting, January 21, 2016.

market transparency and access to many sources of alternative generation supply and contractual counterparties through which to secure future power needs. For a similar reason, an RTO market structure enhances the potential benefits achievable from introducing partial or full retail choice. Under the EIM and in the two RTO options we modeled and evaluated, transactions, generation dispatch, and other wholesale functions are run by a third party that is independent from any individual market participants or industry sector. This independent market operator is answerable to a broad body of members so that no single market participant or sector controls the entity's operations or governance. Trade can therefore proceed on a level playing field, allowing all market participants equal access to the benefits of wholesale power markets. None of these wholesale market reforms would change the state's jurisdiction and authority to oversee integrated planning, resource investments, or retail rates of investor-owned utilities.[9]

If South Carolina transitions toward a JDA or regional wholesale market model, implementation timing and complexity will be an important consideration for maximizing long-term benefits and minimizing transition risks. For both the JDA and to a lesser extent a new Southeast EIM, there is a risk that the more incremental initial steps could delay the timeframe for full RTO participation, thus delaying realization of greater consumer benefits. Creating a new Southeast EIM, regional resource adequacy market, or RTO could similarly be time-intensive efforts that are dependent on coordination with entities beyond South Carolina's direct control. It may be possible to compress implementation timeframes if other states and utilities in the Southeast were willing to undertake this step and the new Southeastern market structure were implemented with support from one of the existing U.S. ISO/RTO organizations.[10]

Joining an existing neighboring RTO (i.e., PJM) is the most expeditious path to full RTO membership. PJM has extensive and recent experience integrating new utility balancing areas, with integration of new members taking as little as 18 months. Under this model, South Carolina would operate within all existing RTO market and governance structures, including the option to retain its vertically-integrated and state-jurisdictional utility structure.

Another pathway that South Carolina could consider would be to integrate with PJM wholesale markets, but under an alternative membership and governance model that is tailored to the unique requirements of South Carolina and other Southeastern states. Examples of similar

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9 Electric cooperative and municipal utilities operate under a different regulatory model, in which the state's authority to regulate retail rates is limited. This would not change under any of the wholesale market reforms discussed in this report.

10 For example, when Colorado and Wyoming utilities considered forming a new "Mountain West" RTO, they received proposals from SPP, CAISO, MISO, and PJM to design and create the contemplated RTO within just a few years. Mountain West Transmission Group, Frequently Asked Questions, updated January 5, 2017.

arrangements include the Western EIM and Extended Day-Ahead Market (EDAM), the Markets+ option offered by Southwest Power Pool (SPP), and the Western Power Pool (WPP) Western Resource Adequacy Program (WRAP). In each of these cases, the participating states, public power entities, and utilities wished to achieve the economic and reliability benefits of pooling resources within a broad regional marketplace; but wanted to do so under a new governance structure that suited the specific state policy and regulatory models of those regions. The economic benefits achievable under such a pathway are identical to those described under the Southeastern RTO and PJM options described in Table ES-1 above, but would require more extensive coordination across states and utility areas over a longer timeframe to achieve consensus and develop the governance and membership models.

Related to the EIM, Southeast RTO, and PJM RTO membership and integration options, the greatest benefits will be realized if the South Carolina utilities are joined by other utilities with neighboring service areas to achieve a larger scope of regional coordination of the energy market and resource adequacy framework across a more diverse footprint. This suggests that policymakers and utilities in South Carolina should join with other states and utilities to coordinate in the decision-making process toward joining or creating a regional RTO or EIM and resource adequacy framework, even if entry dates are uncertain.

Based on these findings regarding wholesale market reforms, we recommend that South Carolina consider immediately initiating processes to join, create, or integrate with a regional RTO marketplace. We recommend to:

- **Establish a policy and timeframe for integrating with an RTO**, considering at least three alternative pathways for full RTO integration:
  - *Join an existing RTO* (i.e., PJM) under the existing governance and membership model (South Carolina would maintain all authorities over vertically integrated utility planning and ratemaking, but would not be in a position to dictate any changes to the existing RTO governance structure); **or**
  - *Create a new Southeast RTO,* provided that neighboring states and utilities show interest in initiating the multi-state effort to create a new RTO; **or**
  - *Integrate with an existing RTO but under a new governance model,* such that energy and resource adequacy benefits can be achieved, but under a governance structure that is suited to the prevailing state regulatory model in South Carolina and other states in the Southeast (e.g. possibly modeled after the Western EIM and EDAM, SPP's Markets+, and WPP's WRAP).
- **Seek coordination with other states and utilities across the Southeast,** particularly North Carolina, toward a regional markets pathway that maximizes the geographic footprint and coordinated use of regional transmission infrastructure; and
- **Authorize the PSC to review and approve each utility's regional integration plan** subject to defined criteria and timelines. [11]

RESOURCE PLANNING AND COMPETITIVE INVESTMENT REFORMS

The second category of potential reforms relates to how long-term resource investment, resource retirement, and supply contracting decisions are made. Current practice in South Carolina relies on Integrated Resource Plans (IRPs) conducted by the utilities individually for each of their service territories, which are subject to PSC oversight and consider interveners' comments. An IRP accounts for the utility's projected demand and resource needs, planned

[11] As two examples of legislation in other states, Colorado Senate Bill 21-072 and Nevada Senate Bill 448 establish relevant authorities, timelines, and evaluation criteria for regional market integration. Both states offer relevant experience for South Carolina given their similar, vertically integrated utility models and reliance on integrated resource planning under state regulatory oversight. See General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, signed June 10, 2021.

resource retirements and supply contract expirations, new generation investments, demand-side programs, and procurements proposed to meet projected future resource needs. Once the PSC approves a utility's supply plans within the IRP or follow-on processes, including approval through the Certificate of Public Convenience and Necessity (CPCN) process, the utility develops the resources and, once these resources are completed, becomes eligible to recover associated costs from consumers, including a rate of return on investments.[12] Going forward, an increasing portion of supply needs could be procured via competitive solicitation processes from third-party Independent Power Producers (IPPs), depending on the outcomes of several active regulatory dockets and ongoing solicitation processes.[13]

There are several options for introducing enhanced planning and competition into South Carolina's resource investment decisions, ranging from incremental to more foundational changes. The resource planning and competitive investment reform options we examined are:

- **Introducing a statewide IRP across all South Carolina utilities**, the goal of which would be to achieve efficiencies by considering all supply needs on a statewide basis with an enhanced role of state agencies to directly oversee the state IRP process or to coordinate among separate utility IRPs. The statewide identified needs could then be developed under utility self-supply or procured via statewide or utility-specific competitive solicitations;
- **Expanding the role of competitive solicitations in utility IRPs**, that seek to meet IRP-defined resource requirements from among competitively-bid projects that can be proposed by the incumbent utility, neighboring utilities, third-party IPPs, demand response aggregators, or other developers. All-source solicitations offer the additional benefit of supporting competition across alternative technologies as well as across alternative providers. South Carolina is in early stages of experience with such competitive solicitations, whose role can be expanded in the future;
- **Transitioning to partial or full reliance on competitive supply investments**, in which a regional resource adequacy mechanism or capacity market would be used to attract a portion or all of future supply investment needs. Such a structure maximizes competitive pressures relative to resource price (leaving states and consumers to pursue any non-price policy priorities through complementary IRP, policy programs, or contracting choices). A market-based approach to supply investments would reduce the cost, increase price transparency,

[12] Electric cooperatives and municipal utilities do not earn return on investments.

[13] The option (but not the requirement) to rely on competitive solicitations was introduced in the 2019 Energy Freedom Act. See South Carolina Office of Regulatory Staff (ORS), Summary of the South Carolina Energy Freedom Act, September 2019.

and shift the risk of uneconomic or stranded investments for customers (who currently pay for regulated investments, even those that prove uneconomic in retrospect) to private companies (who would not be allowed to charge customers more even if they failed to recover the cost of poor investments). The potential to protect customers from exposure to any future stranded investment costs is particularly salient in South Carolina given recent experience with the V.C. Summer nuclear plant expansion.[14]

- **Considering the option for securitization of costs related to retiring stranded thermal assets**, (i.e., those assets that are no longer cost-effective to continue operating, but whose investment costs have not yet been recovered by the utility). Once a thermal asset is considered stranded, "securitization" can reduce the costs imposed on customers and could be considered as an alternative or supplement to ongoing cost recovery, accelerated depreciation, or prudence-based disallowances.

Table ES-2 summarizes our qualitative assessment of the potential benefits and costs/risks associated with these resource planning and competitive investment reform options, including an assessment of their relevance within South Carolina's context.

[14] Though not the focus of this study, experience with the V. C. Summer nuclear plant expansion provides a vivid example of stranded asset risk. The V.C. Summer expansion construction and associated cost recoveries were approved by the Board of Directors of Santee Cooper and the South Carolina PSC under a special process enabled by the 2008 Baseload Review Act (later repealed in 2018). Though the project was never completed, approximately $9 billion in expenditures for partial construction will need to be recovered from customers over the next decades. See Post and Courier, "Santee Cooper, SCE&G pull plug on roughly $25 billion nuclear plants in South Carolina," July 31, 2017; Utility Dive, "Santee Cooper, SCANA abandon Summer nuclear plant construction," July 31, 2017; and Santee Cooper, Annual Report 2021, March 11, 2022.

TABLE ES-2: RESOURCE PLANNING AND INVESTMENT REFORMS POTENTIAL BENEFITS, RISKS AND IMPLEMENTATION CONSIDERATIONS

Option	Potential Benefits	Potential Costs and Risks	Implementation Considerations
Status Quo with Utility IRP	• PSC oversight and approval of investment choices in public interest • Ability to weigh both cost & non-cost criteria in planning (e.g., jobs, environment, equity)	• Relies on utility and PSC judgement and forecasting to select resources • Customers retain most of the risk of uneconomic investments • Limited role for IPPs with lower-cost options	• No reforms
Statewide IRP Across All South Carolina Utilities	• Coordination of analysis across greater statewide scope • Maintains PSC oversight and approval of investment choices • Can inform policymakers weighing major policy changes (e.g., environmental policy) • Reduced reliance on utility planning judgement and forecasts	• Risk of uneconomic investments mostly stays with customers • Increased reliance on state agency planning judgement and forecasts	• Requires expanded planning authorities in PSC or other state agencies • Resource investments could be utility self-supply, utility contracts with IPPs, or based on "single buyer" model w/ a state entity as contractual counterparty to IPPs
Expanding the Role of Competitive Solicitations in Utility IRPs	• Lower costs from increased competition for supply commitments across technologies and suppliers • Maintains PSC oversight and approval of investment choices • Shifts more risk from customers to producers (e.g., fixed-priced contracts) • "Market test" can affirm cost-effectiveness of utility self-supply	• Investment recovery risks stay with customers over contract duration • Utility incentives favor self-supply • Barriers to ensuring level competition between utility-proposed projects vs. IPP-proposed projects	• Need to develop and refine all-source procurement structures relative to best practices • Option to mandate solicitations to meet most or all future resource needs • PSC or other agency oversight of independent evaluator can ensure fair competition (particularly if utility self-supply projects can compete)
Transition to Partial or Full Competitive Supply Investments	• Competitive forces drive cost reductions and supplier innovation • Any risks of poor investment choices borne by private companies (stranded asset costs cannot be passed to customers)	• Transition costs and risks from fundamental changes to utility business model • Investment choices driven only by market prices (i.e., reliability at least cost); reduced consideration of non-price policy objectives	• Transition plans needed for utility-owned generation assets (e.g., incremental transition, divestiture, or functional separation) • With divestiture, transition plan needed to recover legacy investment costs
Securitization of Costs Related to Retiring Stranded Thermal Assets	• Can reduce customer costs associated with stranded asset retirements • PSC would have authority to grant securitization of retiring stranded assets	• Requires mechanism (e.g., rate surcharge) to guarantee cost recovery of securitized amounts. • Removes PSC authority to disallow cost recovery	• Can be implemented with minimal changes to existing law

The scale of the benefits that could be achieved from a more coordinated and competitive resource investment model depend on the level of competition introduced, the timeframe over which major supply investment decisions will be made, whether the competitive reforms follow best practices for achieving the relevant benefits, and whether transition risks are adequately mitigated. Table ES-3 summarizes the potential customer savings that could be achieved from competitive resource procurements under a scenario where South Carolina joins an RTO with a regional capacity market and begins participating either: (a) on a limited basis, with utilities continuing to rely on IRP-based resource development (as is the case under the status quo with limited or no use of competitive solicitations), but using the capacity market to procure incremental needs or sell surplus capacity; or (b) on a more comprehensive basis, relying on the market to attract the lowest-cost resources to satisfy all identified capacity needs.

Benefits would begin accruing immediately upon joining an RTO with a regional capacity market, but would tend to grow over time as the market is used to attract a lower-cost resource mix compared to what otherwise would have been developed under the status quo model. The higher end of this range reflects the benefits from a successful transition to competition for all resource needs (with proper risk mitigation). More modest or incremental reliance on competitive solicitations can be expected to achieve a proportion of these estimated benefits that is commensurate with the share of going-forward investments subject to competitive forces.

TABLE ES-3: POTENTIAL SAVINGS FROM COMPETITIVE SUPPLY INVESTMENTS (2022$ MILLION/YEAR)

Scenario Name	Scenario Description	Immediate Customer Savings ($mln/year)	Long-Term Customer Savings ($mln/year)
Incremental Participation	Maintain utility IRP process for bulk capacity needs but use regional capacity market for purchasing incremental needs and selling surplus	$25–$120	$150–$300
Full Participation	Graduated transition from utility IRP to competitive supply investment via capacity market for full capacity needs	$25–$120	$150–$370

Sources/Notes: Reported in nominal U.S. dollars. Savings arise from reductions to reserve margins due to supply and load diversity over a larger footprint, net capacity surpluses being sold into the market thus offsetting customer costs, the ability to right-size capacity holdings every year, and from attracting low-cost capacity resources such as demand response and uprates that may otherwise not be identified. Immediate savings are those experienced in the first few years upon joining with an RTO due to the ability to recover some capacity costs associated with any existing supply surplus above the new lower capacity requirement through market revenues. Long-term savings are those experienced later in the future after new build capacity is needed. The two scenarios are the same in the initial years because legacy investments have already been made regardless of how South Carolina decides to participate in the market in the future.

Based on our assessment of potential supply investment reform options, we recommend that South Carolina policymakers consider the following options to incrementally introduce competition over time. We note that many of these reform options are complementary to each other (not mutually exclusive alternatives).

We recommend that South Carolina:

- **Join, create, or integrate with an RTO or regional resource adequacy market that ensures resource adequacy (accounting and enforcement) over a larger, more diverse footprint**. This step would yield immediate cost savings by reducing reserve capacity requirements for South Carolina utilities, by enabling the utilities to more cost-effectively manage temporary surpluses and deficits in their resource plans, and by easing the logistics of major plant retirements. If South Carolina additionally wanted to create the option to transition to a model that is partly or fully reliant on competitive generation investments in the future, we recommend prioritizing consideration of an RTO with a track record of attracting competitive generation investments.
- **Authorize the PSC or other state agencies to consider or conduct statewide IRP processes,** if the PSC identifies a benefit to conducting such an exercise, either to achieve cross-utility coordination benefits, better inform policy choices on a statewide basis, or provide statewide needs assessments for the purpose of competitive solicitations. The option for an agency-overseen statewide IRP could be utilized either on an ad hoc basis when a specific need is identified, or could be incorporated into regularized IRP processes.
- **Incrementally introduce and expand the role of competitive solicitations within utility and/or state IRP processes**. South Carolina is presently gaining more experience with competitive renewable and all-source solicitations, which (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved via options such as: (a) requiring (rather than "allowing" as is done currently) future supply needs identified in IRPs to be met through all-source competitive solicitations; (b) designing competitive solicitations that will consider utility self-build projects alongside IPP projects, authorizing state agencies to rely on an independent evaluator to conduct the process and recommend winning projects to the PSC for approval; (c) enabling cooperative and municipally owned utilities to participate in state agency or utility-specific procurements, allowing them the option (but not the obligation) to procure a share of selected resources; and (d) (after joining an RTO) considering the option for

reliance on regional markets for providing a defined portion of IRP-identified supply needs.

- **Confirm or clarify regulatory policies related to the retirement of uneconomic aging resources** to ensure that utilities have the ability and incentive to retire aging generating assets when other lower-cost supply options become available. In determining the most beneficial outcomes for ratepayers, authorize the PSC to utilize all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization.
- **Consider additional competitive investment reforms in the future.** After gaining experience with RTO market participation, competitive IRP-based procurement processes, and retail market reforms (discussed below), reassess the question of competitive investment reforms to determine whether further transition to competitive investments is desired. If so, consider utilizing a graduated transition path that would rely increasingly on competitive generation investments over time as demand increases, existing resources retire, and existing contracts expire.

RETAIL MARKET REFORMS

The third category of potential reforms relates to the retail market and focuses on the question of whether and how customers can select alternative sources or providers of retail electricity. South Carolina customers currently receive retail electricity from the utilities that have been awarded exclusive rights to serve customers within their service territories. For most customers, the PSC approves the level and structure of the electricity rates that utilities can charge to each class of customers in accordance with the cost-of-service rate regulation approved by the PSC. Customers seeking different rate structures, more access to clean energy resources, or investment in distributed resources (such as rooftop solar or battery storage) have the ability to participate in utility-offered programs where they exist, signal interest in new programs through requests to their utility, and act as interveners before the PSC when regulations for new programs or rates are being considered. Customers that remain dissatisfied with the rates, available programs, or other aspects of their utility-provided retail service are not able to seek an alternative retail electricity provider.

There are several options for introducing greater retail choice into South Carolina, ranging from incremental to more foundational changes. The retail reform options we examined are:

- **Utility retail rate reforms to offer additional customer choices**, that would authorize or require utilities to design more efficient or advanced retail rates structures, with the goal of offering customers more choices on rate structure, green power offerings, incentives to improve consumption management to reduce their bills, or opportunities to leverage distributed resources, electric vehicles, or new electric heating technologies such as smart thermostats and heat pumps. Enhanced retail rate design that follows the fundamental principle of cost-causation can lead to improvements in equity and fairness in cost recovery by removing unintended cost-shifting among customer classes and mitigate distribution cost spending by encouraging customers to use electricity more efficiently.
- Enabling **partial retail choice** for large commercial and industrial (C&I) customers, so that these customers have the ability to seek self-supply or contract with a third-party electricity supplier. Under partial retail choice, the incumbent utility would remain the provider of distribution, transmission, and metering services, but would no longer be the only company able to provide generation, or retail services. Customers would be able to negotiate their electricity rates in terms of the price, rate structure, level of hedging, preference for green resources, Demand Response (DR) and Distributed Energy Resource (DER) management, or other features. In other states, large customers have demonstrated a high level of sophistication around their consumption and tend to exercise their right to choose alternative retail energy suppliers. While not strictly necessary, the benefits of partial retail choice are greatly enhanced when paired with a regional wholesale market and most states that have enabled partial retail choice are within existing RTOs.
- Enabling **full retail choice** including residential and small business customers, can offer the same benefits of competitive retail markets and alternative suppliers to small customers (though only a subset of residential customers have tended to exercise their right to switch to an alternative retail supplier in other regions). If pursuing full retail choice, this should be done in a coordinated timeframe with a shift to competitive supply investments to ensure that customers have a meaningful variety of options for securing wholesale and retail supply. This effectively requires an RTO.
- Enabling **Community Choice Aggregation** is an option for enabling communities (even those not served by a municipally owned utility) to select a third-party supplier of retail electric service. Communities in other states have often exercised their option to seek third-party supply as a means to reduce costs, reflect environmental goals, or (usually) both. While not strictly necessary, the benefits of CCAs are greatly enhanced when paired with a regional wholesale market and most states that have enabled partial retail choice are within existing RTOs.

- **Competitive reforms to enable distributed energy resources,** are those options that focus on creating opportunities to incentivize and leverage third-party DR and DER providers to provide value to support bulk system needs (capacity, balancing) or end-use customer value (green energy, bill reduction, more efficient consumption, etc.). RTO markets offer a substantial variety of such opportunities to aggregators of DERs and DR who, according to FERC Order 2222 rules, must be enabled to compete fully in wholesale markets to serve all defined grid services as long as the DER/DR resource in question meets technical capability standards. Competitive all-source solicitations also offer opportunities to leverage new DER/DR technologies, but require a technology-neutral suite of product definitions and programs to fully enable the potential.
- Establishing a **third-party energy efficiency administrator** could create an opportunity to regularize and expand energy efficiency (EE) programs to leverage opportunities that are cost-beneficial to customers but that have not been fully developed under existing structures.

Table ES-4 summarizes the relative advantages of the range of retail reform options identified by the Study Committee and Advisory Board for detailed review in this study.

TABLE ES-4: RETAIL REFORMS POTENTIAL BENEFITS, RISKS & IMPLEMENTATION CONSIDERATIONS

Option	Potential Benefits	Potential Costs & Risks	Implementation Considerations
Status Quo with Exclusive Utility Service for Retail Supply	• Customers enjoy price stability as most investment costs are recovered over a long period • Rates and investment choices subject to state oversight	• Investment and fuel price risks borne by customers under cost-of-service regulation • Customers unable to negotiate, switch providers, or pursue self-supply if unsatisfied with service	• No reforms
Utility Retail Rate Reforms to Offer Additional Customer Choices	• Enhanced rates can offer better efficiency, green supply options, and DR/DER incentives	• Requires careful design to offer system-wide benefits and protect customers who are not able to take advantage of new options	• Some reforms already possible and the legislature can explicitly authorize/mandate others (subject to PSC oversight)
Partial Retail Choice (large C&I customers only)	• Empowers large customers and businesses to negotiate lower or differently-structured rates, self-supply with clean energy, and participate as DR/DER in RTO • Would lower costs for businesses in the state	• Need to equitably address cost recovery of utilities' legacy investment costs (either shift to customers ineligible for switching, assign exit fees, or issue transition charges to customers eligible for switching)	• Legislation required to enable partial retail choice but can be implemented without any coordination from neighboring regions
Full Retail Choice (including residential and small businesses)	• Enables all customers (large and small) to pursue their preferences for clean energy supply, innovative rate structures, or other service offerings from competitive retailers	• Regulatory and data barriers can prevent retailer innovation (may materialize as low switching rates) • Retail products can be confusing to unknowledgeable buyers of electricity, potentially exposing them to greater market volatility	• Regulated service options need to be designed for customers who do not choose competitive options • Regulatory oversight needed to implement switching rules, unbundle rates, design and assign exit fees, and ensure consumer protection
Community Choice Aggregation (CCA)	• Empowers communities to negotiate rates and contract with other suppliers (e.g., for lower rates or policy goals)	• Need to equitably address cost recovery of utilities' legacy investment costs	• Legislation required to allow CCAs to form but can be implemented without any coordination from neighboring regions
Competitive Reforms to Enable DERs	• Can result in higher volume and more valuable DER deployment which enhances system efficiency for all users	• Early programs require testing and validation to be relied upon at scale	• Best enabled via RTO participation and incorporation of in all-source procurements
Third-Party Energy Efficiency Administrator	• Dedicated entity could develop greater and more innovative EE programs	• Need to ensure effective measurement and verification (status quo EE poses similar challenges)	• Legislation required to create EE administrator and establish funding and oversight model

We find that a measured approach to introducing retail access could offer benefits to South Carolina customers, particularly if initially focusing on enabling partial retail choice for large C&I customers and communities (via Community Choice Aggregations (CCAs)). These consumers are sophisticated buyers, able to take advantage of retail competition to procure electricity supply in alignment with their preferences. More options for retail choice would permit these buyers greater flexibility to control costs and tailor electricity service to their environmental goals and business operations. Enabling partial retail choice would allow South Carolina to compete on a more level playing field with other states to attract investment by these large consumers that can spur economic development in the state.

Initiating utility participation in a regional EIM or RTO market before or at the same time as introducing retail choice will amplify the benefits that could be achieved by partial (or full) retail choice, because these types of competitive wholesale markets offer greater pricing transparency and provide customers and retail providers with access to many more energy supply counterparties and self-supply options. For the same reason, EIM or RTO participation will also benefit municipally owned utilities, electric cooperatives, and communities by offering access to more options for procuring wholesale electricity supply on behalf of their members.

Based on these analyses of retail reforms summarized above, we recommend that South Carolina consider the following options:

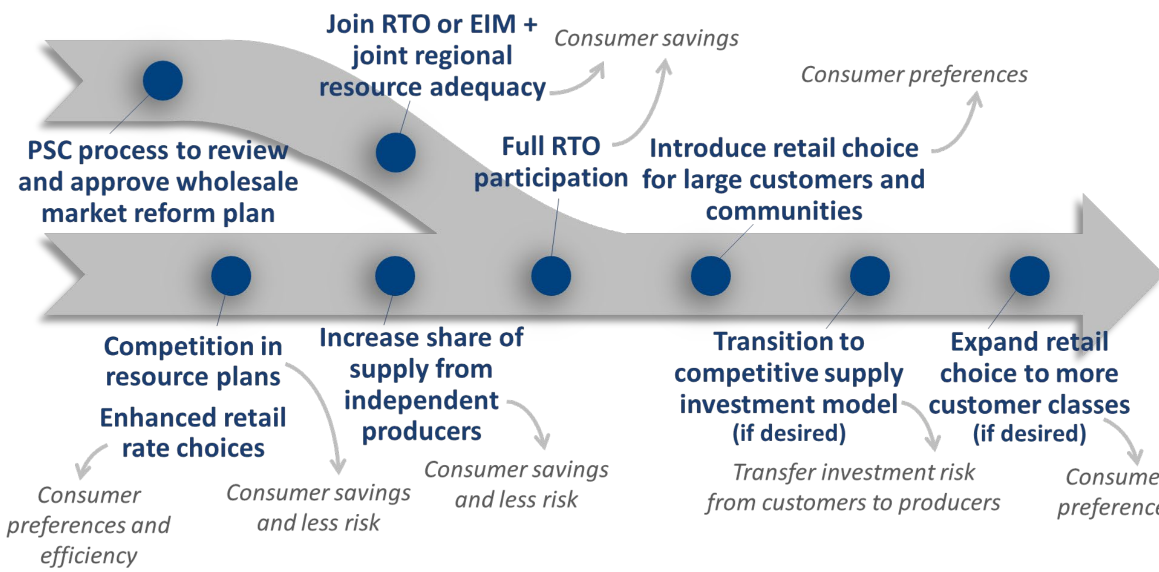
- **Pursue a path toward greater regional coordination via an EIM or RTO wholesale market** to support enabling additional retail rate choices to retail customers. Entering an RTO will immediately increase competitive forces by empowering cooperative and municipal utilities in South Carolina to consider a greater variety of self-supply and contractual options for securing their energy supply.
- **Authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices** to South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, green tariffs and related green energy options, and other rate designs to enhance efficiency.
- **Introduce partial retail choice for large C&I customers**, enabling businesses that are large, sophisticated energy consumers to negotiate rates, self-supply with clean energy, participate in RTO markets as demand-side resources, and optimize their own consumption.
- **Introduce a path for Community Choice Aggregation**, enabling local communities to pursue environmental goals and negotiate rates.
- **Defer consideration of retail choice for residential and small business customers** until after other reforms are implemented. Revisit the option to expand retail choice to all consumers after gaining experience with wholesale market participation, partial retail choice, and the other market reforms discussed above.
- **Enable distributed energy resources and demand response** from third-party providers to compete in all-source supply solicitation, both within competitive IRP-based all-source procurement processes and within RTO markets.
- **Authorize the PSC to appoint a third-party EE administrator** to support energy efficiency program development in utility territories where substantial cost-effective EE opportunities exists to reduce customer electricity bills but that have not been fully pursued under existing structures.

POTENTIAL MARKET REFORM PATHWAYS

The market reforms we examine in this study can interact with one another in ways that are beneficial if they are implemented in a well-structured sequence. Conversely, the set of recommended reforms could interact poorly if implemented out of sequence or if they are not well-designed. Further, the reform path should maintain a self-consistent approach across each stage of sector transition, given the potential for reforms to be paused or concluded midstream.

If South Carolina chooses to proceed with some or all of the market reforms examined and recommended in this study, they should be introduced in a carefully staged fashion. Figure ES-1 below provides a high-level overview of a reform pathway for South Carolina that is likely to achieve immediate benefits, make steady progress toward an increasingly competitive electricity sector that can provide customer benefits, and avoid problematic interactions among the major market reform elements.

FIGURE ES-1: ILLUSTRATIVE PATH TO INTRODUCING COMPETITIVE REFORMS FOR SOUTH CAROLINA



The most logical pathway for South Carolina is to begin with efforts to join or create an RTO, which will provide cost savings for customers in the state and serve as a critical foundation to many of the other market reforms we examine in this study. Once full RTO membership is achieved, it can provide much of the infrastructure needed to enable further reforms for competitive supply investments, partial or full retail choice, and enhancing opportunities for distributed resources and other innovative business models.

Another set of reforms that can be initiated immediately (prior to full RTO membership) relates to enhanced competition for supply contracts under the current IRP model. Subsequent RTO membership would then enhance the range of opportunities available and introduce the possibility of full transition to a competitive investment model.

While we assessed several reform options which would result in varying degrees of change to the electricity sector, our recommendations described above constitute the initial steps along a path that should follow best practice in the sequencing and introduction of various reforms. As such, we do not recommend South Carolina pursue generation divestiture, full reliance on market-based investments for resource adequacy, or full retail choice for all customers at this time. We do recommend that South Carolina join, create, or integrate with a regional wholesale power market that includes regional optimization of transmission usage and commitment, dispatch of generation resources, and regional resource adequacy coordination. These initial reforms would provide the basis from which additional reforms could be pursued in a logical sequence (and in consideration of the complexities and opportunities to mitigate transition risks as discussed in detail throughout this report).

To maximize benefits to South Carolina customers, we recommend that policymakers should determine the most desirable end state along this or a similar reform pathway and then proceed with the reforms under a carefully managed process that follows best practice for mitigating transition risks as discussed more fully in the body of this report.

I. Background

A. Legislative Requirements and Study Process

Pursuant to South Carolina Act 187, the South Carolina Electricity Market Reform Measures Study Committee (the "Study Committee") commissioned Brattle consultants to perform this independent assessment of the benefits of potential electricity market reforms for the state.[15] We assessed a variety of market reform measures, and performed detailed simulations of the electrical system corresponding to alternative wholesale market structures.[16] We structure our recommendations with respect to the context of Act 187, which posed the general question of whether and how market reforms to the electricity sector can benefit South Carolina customers, reduce costs, and protect consumers from excess risk.[17]

Act 187 specifies creation of the Study Committee (consisting of a selection of South Carolina legislators in both the House and Senate) and an Advisory Board composed of participants from utilities, solar developers, consumer advocacy groups, end user representatives, other community groups, and South Carolina utility regulators. It tasks the Study Committee with studying: a variety of enumerated reforms, whether one or more reforms should be pursued, the costs and benefits of any recommended reforms, and development of draft legislation for any recommendations. The Act also directs the Committee to retain an independent consultant to

[15] South Carolina General Assembly, Act No. 187, Electricity Market Reform Measures Study Committee, signed September 29, 2020.

[16] Following the scope enumerated in Act 187, we assessed: a South Carolina Regional Transmission Organization (RTO); a Southeast RTO with South Carolina; joining an existing RTO; a Southeast energy imbalance market; introduction of competition in generation investment; full and partial consumer retail electric service choice; community choice aggregation; restructured markets and high levels of distributed energy resources; joint dispatch agreements for the Carolinas; and retail rates that more closely align consumer interests with electric system interests. In addition, based on feedback from the study committee and advisory board, we assessed: enhanced regional transmission planning; statewide integrated resource planning; securitization related to thermal plant retirements; and a third-party energy efficiency administrator. Each of these reforms is described in detail in Sections II, III, and IV below.

[17] Though not the subject of this study, the Act 187 was drafted and passed over the course of 2020, a time of change for the utility sector in South Carolina. SCANA and Santee Cooper had abandoned the 2-unit expansion of the V.C. Summer Nuclear Generation Station in 2017, with major financial implications for each. SCANA merged with Dominion Energy in December 2019, and the state legislature assessed for several years whether to privatize Santee Cooper, ultimately deciding instead to focus on oversight reforms. South Carolina electricity customers continue to pay premiums to recover the capital lost in the V.C. Summer project.

advise the Study Committee and produce an opinion on which reforms would benefit South Carolina consumers (i.e., the present report).

Throughout this process, we have served as an educational resource for the Study Committee and its Advisory Board, and have connected them with other experts and practitioners in the industry who offered additional education and perspectives. We assisted the Study Committee with general study scoping and identifying which market reforms in Act 187 (and other reforms requested by stakeholders) should be subject to detailed analysis (including power system modeling). The Study Committee and Advisory Board provided close feedback and support for the execution of this effort throughout. For more information see Appendix D.

B. Overview of South Carolina's Electricity Sector

The electricity sector in South Carolina, similar to that in thirty-three other U.S. states, is based on the vertically integrated utility model with cost-of-service regulated retail rates.[18] Vertically integrated utilities: (i) own and operate (most) generation, transmission, and distribution (with cost recovery through regulated retail rates); (ii) conduct near term operations and long-term generation and transmission planning; (iii) administer interconnection of independent generation; (iv) charge federally-regulated transmission rates for inter-utility trading; (v) purchase or sell wholesale power in wholesale markets and/or bilaterally with neighboring utilities; (vi) perform distribution system planning and operation; and (vii) serve retail customers.

In South Carolina, the Investor-Owned Utilities (IOUs) include Duke Energy Progress and Duke Energy Carolinas (collectively "Duke"), Dominion Energy ("Dominion"), and Lockhart Power Company ("Lockhart"). The South Carolina Public Service Authority ("Santee Cooper") is state-owned and follows some of the same regulatory structure as the IOUs, but has a more complex governance and oversight model based on the recently implemented reforms in Act 135, signed in 2020.[19] Electric cooperatives, owned by their members, and municipal utilities, owned by local governments, also serve a significant proportion of customers in South Carolina. Vertically integrated utilities are responsible for all segments of the electricity value chain from the generation of electricity to final delivery to customers in their service areas, as shown in Figure 1 below.

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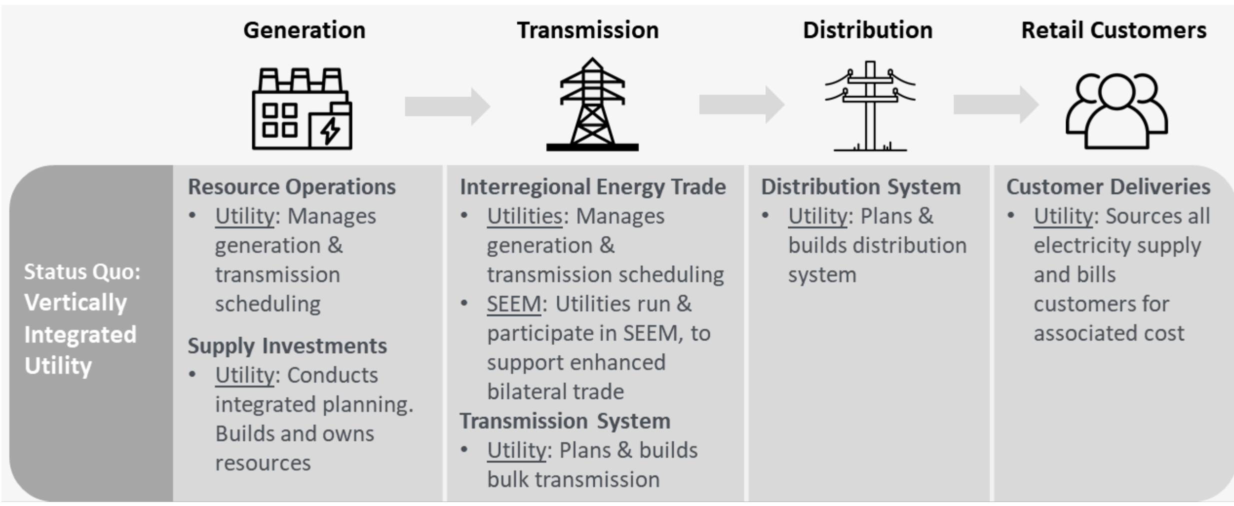
[18] The other U.S. states and the District of Columbia have deregulated their industry structure and introduced retail choice. See Electric Choice, "Deregulated Energy Markets," January 9, 2023.

[19] South Carolina General Assembly, A135, R140, H3411, enacted May 19, 2020.

To provide electricity service, South Carolina investor owned utilities are granted monopoly status in their service territory and are regulated by the South Carolina Public Service Commission (PSC). The PSC is the state-level regulator responsible for adjudicative functions and approves regulated rates of return on investment for vertically integrated utilities, regulates investments in generation and the distribution system, establishes bundled retail rates charged to customers, and approves long-term planning efforts that utilities are required to file periodically known as Integrated Resource Plans (IRPs).

FIGURE 1: SOUTH CAROLINA'S CURRENT SECTOR MODEL WITH VERTICALLY INTEGRATED UTILITIES



Source/Notes: The term SEEM refers to the Southeast Energy Exchange Market. This figure illustrates which roles in each section of the electricity value chain vertically integrated utilities play under the status quo.

As shown in Table 1, the IOUs serve 0.3% (Lockhart), 7% (Duke Energy Progress), 26% (Duke Energy Carolinas), and 27% (Dominion) of South Carolina energy demand directly. Additionally Santee Cooper serves 12%, electric cooperatives serve 23%, and municipally owned utilities serve 4% of South Carolina's retail load. Electric cooperatives receive approximately 80% of their wholesale power from Santee Cooper and 20% from Duke Energy Carolinas while municipalities receive approximately 26% of their wholesale power from Dominion and 74% from Duke Energy Carolinas.

In addition to their role as vertically integrated utilities and distribution providers, Duke, Dominion, and Santee Cooper also act as the Balancing Authorities (BAs) that manage real-time energy generation and supply within their Balancing Authority Area (BAA) of the broader regional bulk transmission system. In their roles as BAs, these same companies support energy deliveries to 8% (Duke Progress), 28% (Dominion), 30% (Santee Cooper), and 34% (Duke Energy Carolinas) of South Carolina's retail electricity customers.

For the purposes of this study, we will discuss the role of these entities both as BAs (collectively, the four companies serve all South Carolina customers in this role) and as vertically integrated utilities. In total, 31 separate utility companies serve South Carolina customers under a range of ownership structures and business models.[20] Figure 2 below shows the balancing areas of the four South Carolina Balancing Authorities.

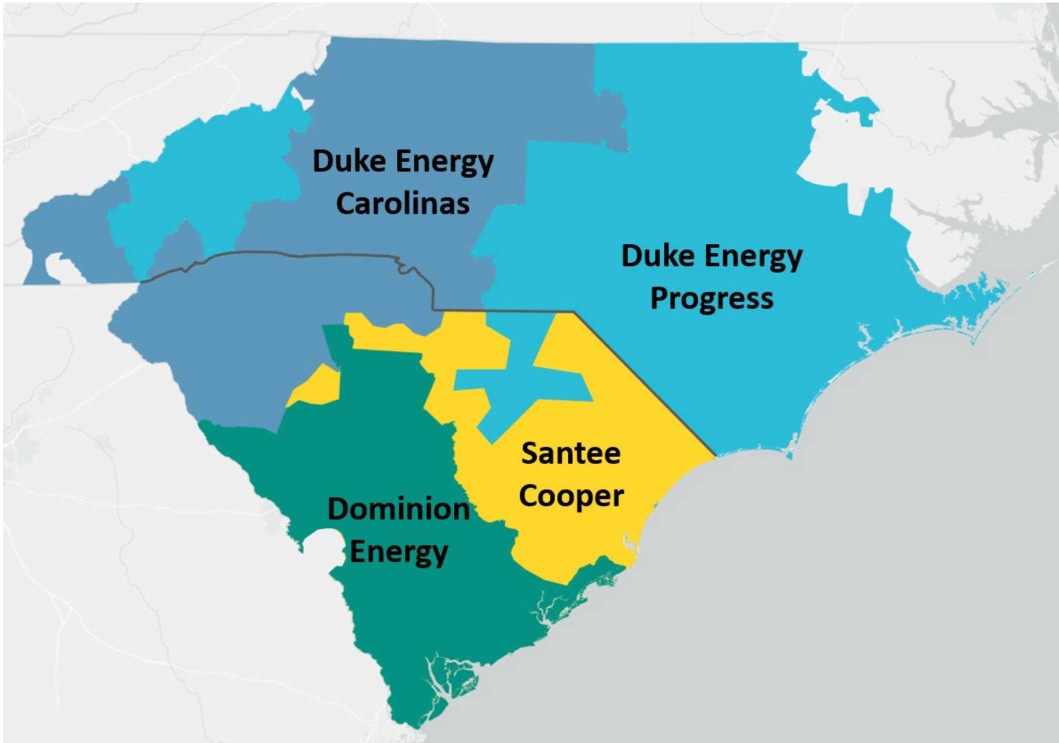
TABLE 1: SHARE OF SOUTH CAROLINA DEMAND SERVED BY EACH BALANCING AUTHORITY AND DISTRIBUTION UTILITY

	Balancing Authorities					
	Duke Energy Carolinas	Santee Cooper	Dominion Energy	Duke Energy Progress	Total	Share of SC Energy Demand
	MWh	MWh	MWh	MWh	MWh	%
Utilities that are also BAs						
Dominion Energy (IOU)			21,411,242		**21,411,242**	**27%**
Duke Energy Carolinas (IOU)	20,440,331				**20,440,331**	**26%**
Santee Cooper (State-Owned)		9,189,290			**9,189,290**	**12%**
Duke Energy Progress (IOU)				5,934,799	**5,934,799**	**7%**
Coops, munis, IOU, and adjustments						
Cooperative	3,688,944	14,384,938			**18,073,882**	**23%**
Municipal	2,229,968		783,157		**3,013,125**	**4%**
Lockhart Power Co. (IOU)	204,662				**204,662**	**0.3%**
Behind the Meter	39,935		39,784		**79,719**	**0%**
Adjustment 2021	768,673	422,127	72,107	182,179	**1,445,086**	**2%**
Total SC Deliveries	**27,372,513**	**23,996,355**	**22,306,290**	**6,116,978**	**79,792,136**	**100%**
Share of Deliveries to SC customers	**34%**	**30%**	**28%**	**8%**	**100%**	

Source/Notes: Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021.

[20] Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021.

FIGURE 2: SOUTH CAROLINA BALANCING AUTHORITIES



Source/Notes: S&P Global Market Intelligence, LLC, Mapping Tool.

In addition to the vertically integrated utilities and the PSC, there are several other key players in the electricity sector. Independent Power Producers (IPPs) own and operate unregulated generation (generation that does not have guaranteed/regulated cost recovery) or Qualifying Facilities (QFs) and need to apply to interconnect to the utility transmission system through a utility-administered process. QFs are combined heat and power generators or smaller-scale renewable generation resources owned by IPPs that qualify under the Public Utility Regulatory Policies Act of 1978 (PURPA).[21] IPPs have a smaller role in South Carolina where small combined-heat and power and other IPP capacity is 2,664 MW, or approximately eleven percent of total generation in the state.[22] QFs qualify under PURPA for state-regulated rates based on utility avoided costs and must be included by utilities in their resource mix.[23]

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21 The Public Utility Regulatory Policies Act of 1978 (PURPA) a federal legislation which was enacted to encourage fuel diversity by requiring utilities to purchase alternative energy sources thereby opening third-party access to the transmission system and incrementally introducing competition into the electric sector. See Public Utility Regulatory Policies Act (PURPA), Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978.

22 U.S. Energy Information Administration (EIA), South Carolina Electricity Profile 2021, November 10, 2022.

23 Qualifying Facilities are grouped into two types of cogeneration and small renewables and enjoy certain benefits under federal, state, and local laws. The benefits that are conferred upon QFs by federal law generally fall into three categories: the right to sell energy or capacity to a utility, the right to purchase certain services from

The Federal Energy Regulatory Commission (FERC) mandates open access transmission and regulates transmission rates for inter-utility (and any unbundled) usage of the grid. The North American Electric Reliability Council (NERC) sets reliability criteria that govern near-term operations and long-term planning of generation and transmission to ensure that utilities maintain an adequate and reliable system.

The federal government establishes federal energy policy (e.g., tax credits for renewables, PURPA, emissions regulations) while the South Carolina state government establishes energy policy for the state, including incentives for certain types of generation assets and demand side management.

C. South Carolina Market Reforms Assessed in this Study

Compared to South Carolina's vertically integrated model where a utility has the exclusive right to serve customers within a defined service territory, other jurisdictions across the U.S. and internationally have introduced varying levels of competition to various segments of the electricity value chain. Introducing competitive reforms into South Carolina may require adjusting the roles and responsibilities of utilities compared to other players, as briefly summarized in Figure 3. For the purposes of assessing the potential benefits and relevance to South Carolina, we structure our assessment into three areas of potential reform, each of which would require different levels of sector reorganization:

- **Wholesale market reforms** are those that could improve the cost-effectiveness of generation resource operations and trade across regions. The primary sector reorganization under this model would be to shift responsibility for generation dispatch from the individual utilities to a regionally coordinated framework. Among these variations, the wholesale Regional Transmission Organization (RTO) market option offers the greatest level of regional coordination and competition. RTO markets serve the energy needs of approximately two-thirds of customers across the U.S., and serve regions with vertically integrated utilities (like South Carolina) as well as regions that have partly or fully restructured into competitive generation and retail choice models.[24] Many states with utilities that are participating in

utilities, and relief from certain regulatory burdens. See Federal Energy Regulatory Commission (FERC), "What is a Qualifying Facility?," updated on June 11, 2021; and Public Utility Regulatory Policies Act (PURPA), Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978.

[24] ISO/RTO Council, "The Role of ISOs and RTOs," accessed February 7, 2023.

regional wholesale power markets (such as most states with utilities participating in the Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), or the Western Energy Imbalance Market (WEIM) rely on vertically integrated industry structure and a traditional cost of service regulatory model with state-regulated bundled retail electricity rates. In addition to administering energy markets and resource adequacy requirements, these RTOs administer regional open-access transmission tariffs, ensure regional reliability needs, and conduct regional transmission planning.

- **Resource planning and competitive investment reforms** are those that seek to improve the cost-effectiveness of resource investment decisions and shift investment risks away from customers and onto producers. Reforms in this area would create greater opportunities for IPPs to develop and build future generation, storage, and demand response resources instead of relying mainly on the utilities as the only or primary owners and developers of generation and supply resources. These third-party developers would compete to provide the needed resources at the lowest cost to consumers. Variations of this reform range from modest (incrementally introducing competition and shifting a small amount of risk to resource owners) to extensive (relying entirely on market prices to attract investment and shifting all investment risks to resource owners).
- **Retail market reforms** are those that would offer customers greater opportunities to select their retail electricity suppliers based on their preferred resource mix or rate structure. Under different variations of retail market reforms, large customers, communities, or (potentially) even small customers could choose to receive electricity supply from a competitive third-party supplier rather than only from their incumbent utility. Across the U.S., approximately 57% of customer demand is located in states with a competitive retail market model.[25] Depending on how the retail market is established under state regulations, a customer's choice to receive power from another entity could be a reflection of their preferences related to price, rate structure, green energy, pricing risk, customer service, distributed resource programs, or billing interfaces.

These three categories of electricity market reforms are interrelated, chiefly in terms of their natural sequence of introduction. Wholesale market reforms such as participating in an EIM or RTO are typically introduced first, followed by competitive supply investments, and then retail market reforms.

[25] Energy Information Agency (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, accessed February 8, 2023.

FIGURE 3: CATEGORIES OF POTENTIAL ELECTRICITY MARKET REFORMS EXAMINED IN THIS STUDY

	Generation	Transmission	Distribution	Retail Customers
Status Quo: **Vertically Integrated Utility**	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Wholesale Market Reforms	**Resource Operations** • JDA, EIM or RTO: Uses regional coordination or marketplace to schedule generation and transmission	**Interregional Energy Trade** • JDA, EIM or RTO: Maximize benefits of regional trade **Transmission System** • RTO: Supports inter-regional transmission planning		
Resource Planning & Competitive Investments	**Supply Investments** • IPPs: Can develop new resources (competing on price)			
Retail Market Reforms				**Customer Deliveries** • Customers: Select retail provider to procure needed supply (compete on price, green, or other values)

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area. JDA = Joint Dispatch Authority.

Table 2 further describes the scope of reform questions in each of these three categories, and briefly lists the individual reform options examined in this study. As discussed above, the reform options that we examine in detail were selected in close coordination with the Study Committee and Advisory Board, and aim to reflect the options that offer the greatest relevance and most immediate interest in South Carolina's context.

TABLE 2: ELECTRICITY REFORM OPTIONS EVALUATED IN SOUTH CAROLINA'S CONTEXT

Option	Scope of Reform Questions	Reform Options Evaluated
Wholesale Market Reforms	• How are operational decisions made to schedule generation and transmission? • How is interregional energy trade supported? • How much total supply is needed to maintain reliability? • How is the transmission system planned and built?	• Status quo with vertically integrated utilities • Joint Dispatch Agreement (JDA) • Energy Imbalance Market (EIM) • Regional Transmission Organization (RTO) • Enhanced regional transmission planning (within an RTO)
Resource Planning and Competitive Investment Reforms	• How are supply resources selected? • How is the proportion each technology determined (coal, gas, demand response, batteries, renewable)? • Who owns the supply resources? • Who bears the risk of uneconomic investment decisions?	• Status quo with utility IRP • Statewide IRP across all utilities • Competitive reforms to utility IRP • Transition to competitive supply investments • Securitization of costs related to retiring thermal assets
Retail Market Reforms	• Can customers choose their retail supplier? • For non-shopping customers, how and by who is default retail service provided? • Can customers reflect their own preferences of risk, cost, green • How are customer-owned and distributed resources leveraged and incentivized?	• Partial retail choice (available primarily to large customers) • Full retail choice (including small Commercial & Industrial (C&I) and residential) • Community choice aggregation • Competitive reforms to enable DERs • Third-party energy efficiency administrator

II. Wholesale Market Reforms

A. Overview of Potential Wholesale Market Reforms

The scope of the wholesale market reforms we examine for South Carolina relate to bulk grid operations, the processes by which resources operate and transmission is scheduled, including inter-utility exchanges of energy. Wholesale reforms are therefore focused on opportunities to improve daily operations, expand regional coordination and introduce opportunities for competition, and enhance trade among a broader group of participants. Savings from wholesale reforms are derived from economies of scale related to pooling of resources across many utilities, IPPs, utility customers, public power entities, and others, which yields more efficient resource operations, potentially enabling fewer generators to serve customers than otherwise, and more efficient utilization and planning of transmission infrastructure.

Because wholesale market transactions in the regional grid cross state lines and form part of interstate commerce, these markets are subject to regulation by the Federal Energy Regulatory Commission (FERC). FERC's legislative mandate is to ensure that rates and terms of transmission service and wholesale market transactions are just and reasonable and not unduly discriminatory. FERC oversight applies both to the status quo (in which bilateral wholesale trades are effectuated pursuant to each utility's FERC-filed Open Access Transmission Tariff, or "OATT") as well as to the reforms described below (many of which consolidate rates under a single OATT). State policymakers can influence whether FERC regulation applies on a per-utility basis, or instead applies to a collection of utilities grouped under a wholesale market operator.

The options described here span a "spectrum" of wholesale reforms that have been deployed in North America today as shown in Table 3. These options are:

- **Status Quo**: Utilities are responsible for their own operations within their service territory. Interactions with other utilities are either opportunistic (through bilateral trades) or through (occasionally) coordinated long-range planning. FERC oversees bulk system operations and trade via oversight of the Open Access Transmission Tariff (OATT) of each respective transmission utility, which establishes the terms and rates by which utilities, customers, and power producers may schedule bilateral transactions across the transmission lines.
- **Joint Dispatch Agreement (JDA)**: A JDA more closely coordinates the real-time dispatch of generators between two or more utilities. One of the member utilities (e.g., Duke, which

already uses a JDA across its two utilities) acts as operator and governance is via FERC oversight of the BA's OATT, which references the JDA. A JDA operates in the 5-to-15 minute timeframe utilizing any spare transfer capability between the utilities to meet utility loads by more optimally dispatching the JDA-utilities' online generating units. Savings from energy exchanges among utilities are shared and settled after the fact with a predetermined formula. Individual utilities are generally still responsible for their minute-by-minute balancing and operating reserves.

- **Energy Imbalance Market (EIM)**: An EIM optimizes the real-time dispatch of generators against physical transmission constraints across a broader regional footprint composed of several utilities and introduces an independent operator to optimize the dispatch. It is somewhat similar to the JDA in that individual utilities control unit commitment and trading up until real-time operations, however an EIM adds transmission-security-constrained dispatch and congestion management (and in some cases optimized start-up scheduling in real time for flexible offline generators). It also creates transparent location-specific spot market prices and financial settlements at every location for every 5-15 minute dispatch interval. Utilities in an EIM generally remain responsible for their minute-to-minute balancing and provision of operating reserves. As under status quo and JDA options, FERC continues to regulate the coordinating agreements and the rates and terms (the "tariff") for wholesale transactions.
- **Regional Transmission Operator (RTO)**: An RTO pools all generator operations and wholesale functions including both (1) day-ahead unit commitment and market operations and settlements; as well as (2) real-time dispatch and congestion management. Additional efficiencies are obtained through the consolidation of individual utilities' BAs into a single BA. Both real-time generator dispatch and day-ahead resource scheduling are optimized across the entire footprint using Security Constrained Economic Dispatch (SCED). An RTO also conducts regional transmission planning across its member utility footprint, which can span several states. As with the status quo, JDA, and EIM options, the rates and rules of trade remain FERC-regulated under an OATT; however the filing rights to amend the OATT are held by the non-profit ISO/RTO entity and subject to a set of governance rules that offer an opportunity for a broad set of stakeholders to participate in rule reforms.[26]

[26] Under separate utility OATTs in the status quo, the transmission utility alone holds these filing rights subject to FERC approval. Under an ISO/RTO structure, the ISO/RTO entity holds the filing rights to the OATT and voting rights are allocated more broadly to the transmission owners vs. buyers and sellers seeking to use the transmission lines to trade and deliver power.

Under each of these wholesale market reforms, the state retains the authority to set the process to oversee and approve resource investments and retirements, generation and transmission siting, and retail rates.

We note that there are multiple kinds of RTOs as shown in the spectrum of wholesale market reforms in Table 3 below. These include single-state vs multi-state RTOs, and those operating in states with vertically integrated utilities vs. restructured utilities (or a combination of both). To ensure resource adequacy, utilities can trade firm resource availability ("capacity") in wholesale markets alongside energy. Like energy, capacity can be pooled, either in an RTO or in a purpose-built resource adequacy sharing program. Some RTOs allocate a share of the pool-wide resource adequacy requirement and mandate that utilities meet it through self-supply or bilateral arrangements (a resource requirement approach) while other RTOs host a market for trading capacity (capacity market approach). In Texas, resource adequacy is mediated through shortage pricing in the energy market. The spectrum of wholesale market reforms considered in this study also reflects what has been implemented elsewhere in the U.S., but is not an exhaustive illustration of what is possible. Elements from these approaches used in other regions can be combined in a different combination that most optimally reflect South Carolina's market conditions and addresses the state's needs and preferences.

TABLE 3: THE SPECTRUM OF WHOLESALE MARKET REFORMS AND EXAMPLES

<table>
<tr><th colspan="4">Non-RTO Options</th><th colspan="5">RTO Options</th></tr>
<tr><th rowspan="2">Bilateral markets</th><th rowspan="2">Enhanced bilateral markets</th><th rowspan="2">Joint Dispatch Agreement</th><th rowspan="2">EIM
EIM + Day-ahead market
EIM + Resource adequacy</th><th colspan="2">Vertically integrated utilities</th><th colspan="3">Restructured utilities</th></tr>
<tr><th>Resource requirement</th><th>Capacity market</th><th>Resource requirement</th><th>Capacity market</th><th>Energy-only shortage pricing</th></tr>
<tr><td rowspan="2">South Carolina (before SEEM)</td><td rowspan="2">South Carolina (with SEEM)</td><td rowspan="2">Duke JDA
Colorado JDA</td><td rowspan="2">Western EIM
EDAM (pending)
SPP Markets+ (pending)
WRAP (pending)</td><td colspan="2">PJM</td><td rowspan="2">CAISO</td><td rowspan="2">PJM
NYISO
ISO-NE
MISO (IL)</td><td rowspan="2">ERCOT</td></tr>
<tr><td>SPP</td><td>MISO</td></tr>
</table>

Note: This table reflects the dominant regulatory environment in each area however there are smaller exceptions that are not included. CAISO = California ISO, EDAM = Extended Day-Ahead Market, EIM = Energy Imbalance Market, ERCOT = Electric Reliability Council of Texas, ISO = Independent System Operator, ISO-NE =

ISO New England, MISO = Midcontinent Independent System Operator, NYISO = New York ISO, PJM = PJM Interconnection, LLC., SPP = Southwest Power Pool, WRAP = Western Resource Adequacy Program.

Since wholesale markets for power are enabled over regional transmission networks that cover large geographic areas with many utilities, savings related to efficient pooled operations can be enhanced by RTO's regional approach to transmission planning. We therefore also consider options to enhance regional transmission planning in South Carolina and how these options interact with the above wholesale market reforms.

The wholesale market reforms introduce a layer of coordination among utilities that takes the place of obligations and roles currently run internally within the utility. For example, today a utility in South Carolina is responsible for balancing its own supply and demand in real time, reporting to the South Eastern Reliability Council (SERC, the southeastern Regional Entity of NERC) on its performance metrics, and paying any fines when regional or national standards for balancing are not met.[27] Under an RTO, a large portion of this responsibility and risk is transferred to the RTO. The way these roles shift and how they fit in with the overall business of today's utilities is illustrated in Figure 4.

[27] NERC, "Standard BAL-001-2—Real Power Balancing Control Performance," 2015.

FIGURE 4: POTENTIAL ROLE OF WHOLESALE MARKET REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Wholesale Market Reforms	**Resource Operations** • JDA, EIM or RTO: Uses regional coordination to schedule generation and transmission	**Interregional Energy Trade** • JDA, EIM or RTO: Maximize benefits of regional trade **Transmission System** • RTO: Supports regional transmission planning		

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

In the remainder of Section II we evaluate the advantages and disadvantages of these wholesale market reform options, the implications of their governance models, implementation considerations, and conclude by presenting quantitative net benefits for each reform option. As we discuss in more detail, each of the major reform options also offers distinct choices. For example, the RTO option could be achieved by the state's utilities either through joining PJM, by developing a Southeast RTO, or by evolving SEEM into an Energy Imbalance Market with additional functionality added over time such as a day-ahead market and regional resource adequacy framework, eventually evolving into an RTO.

B. Status Quo

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

The utilities in South Carolina serve customer load in their service areas mostly with their own generation. Wholesale trades with other utilities or entities represent an important but relative smaller part of operations compared to generation from their own resources. However, the reliance on wholesale trades varies by utility. Such wholesale trades are conducted on a bilateral basis in markets that range from long-term to hourly and intra-hour. Long-term firm trades can be a helpful supplement to resource adequacy, while trades in the operating time horizon can provide opportunistic cost savings when cheaper generation is available for purchase elsewhere (or provide cost offsets when through revenues from off-system sales to other utilities).

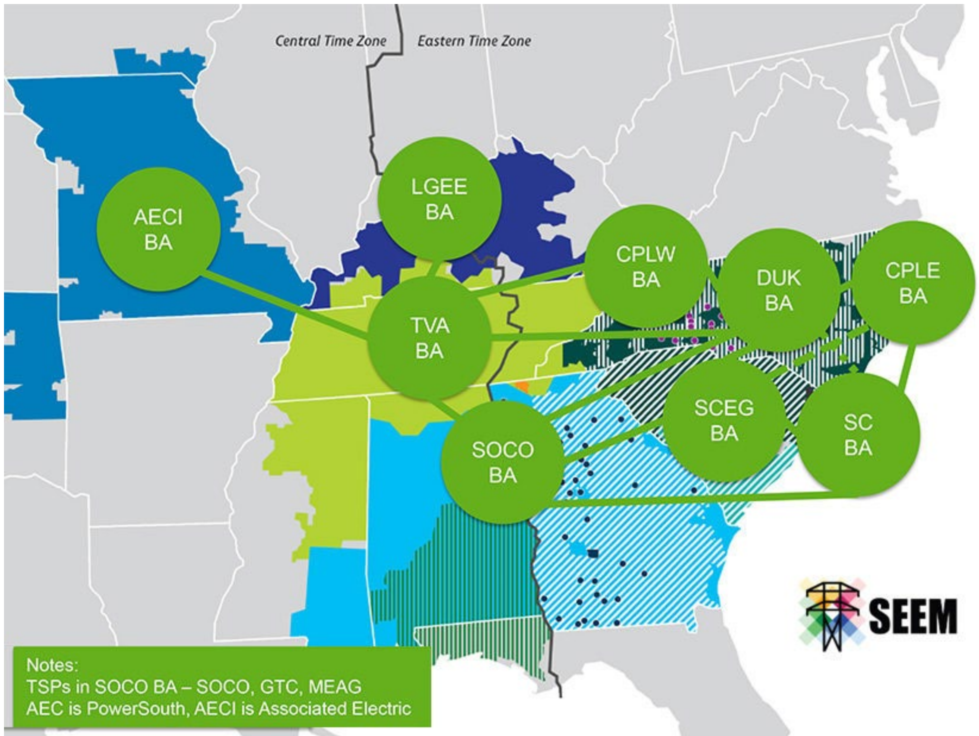
In the minute-to-minute operational timeframe, utilities in South Carolina likewise depend mainly on their own resources to balance load. As explained above, utilities function both to serve customers as well as Balancing Authorities, a NERC role that sets standards for real-time system operations. When demand for electricity rises, each utility dispatches their own generators to increase output in response, which is supplemented by hourly bilateral transactions, ensuring that supply and demand match.[28] In one important operational domain, the South Carolina utilities do pool their generation reserves regionally. The VACAR-South reserve sharing arrangement among South Carolina utilities allows the utilities to share operating reserves to quickly replace the generation from unexpected generator or transmission outages.[29]

The South Carolina utilities participate in the Southeast Energy Exchange Market (SEEM), which launched on November 9, 2022. SEEM is a bilateral-trading platform for matching buyers and sellers of wholesale spot non-firm energy across its footprint. SEEM bilateral trades for energy are finalized close to each 15-minute trading interval (after day-ahead and intra-day trades are completed) and use any available, unreserved transmission without charge. Figure 5 is a map of the SEEM footprint.

[28] The Duke utilities serving South Carolina operate a Joint Dispatch Agreement that includes their North Carolina service areas. They plan to form a single Balancing Authority by 2030.

[29] VACAR-South includes all of the Carolinas, except the portion of Virginia Electric and Power Company's service area in North Carolina.

FIGURE 5: SEEM FOOTPRINT (AS OF FEBRUARY 2021)



Source/Notes: Southeast Energy Exchange Market (SEEM), "[Re: Southern Company Services, Inc. Southeast Energy Exchange Market Agreement,]" Docket ER21-1111, filed February 12, 2021. In addition to the utilities shown, Duke Energy Florida, JEA, Seminole Electric Cooperative and TECO Energy joined SEEM expect to start trading in mid-2023.

Utilities benefit from wholesale trades at all time horizons, from years forward to day-ahead and intraday. Ultimately, these cost savings from trade are passed on to customers via rate adjustments. However, there are significant frictions inherent in bilateral trading that limit their scope and benefit, especially in the day-ahead and other time frames that are not covered by the SEEM platform. These frictions include the need to potentially pay a broker or administrative charge, manually arrange the individual trades by telephone or other means, and coordinate transmission scheduling with the utility.[30] For trades that span several utilities, transmission fees must be incurred for each (called "pancaking" of transmission rates). Regional trade therefore yields less consumer benefit than it is theoretically capable of offering.

ADVANTAGES OF STATUS QUO APPROACH

- Utilities (under FERC oversight for transmission operations and under state regulatory oversight for state-jurisdictional activities) retain significant autonomy and discretion, since they are the sole or primary actor in nearly all functions in the electricity industry.

[30] Prior to SEEM, real-time bilateral trades also included tariff wheeling fees.

- Some level of inter-utility efficiencies achieved through Duke's two-utility JDA and the multi-utility SEEM bilateral market platform.

DISADVANTAGES OF STATUS QUO APPROACH

- Utility-specific OATT and point-to-point transmission rights and scheduling impose high transaction costs and the potential for excess tariffs that produce impediments for cost-effective trade and use of the transmission system, particularly for trade and transactions that might otherwise be scheduled by small utilities, individual consumers, and independent power producers.
- Foregoes significant cost savings that can be derived from pooled operations and planning over a broader geographic footprint.
- Requires more generators or other resources to meet the same level of reliability compared to pooled regional resource adequacy scenarios, such as an RTO or a regional resource adequacy market, that can take advantage of the diversity of loads and resources in a larger geographic region.
- There are fewer operational options available to remediate supply shortages or other emergency conditions.[31]
- FERC OATT oversight model retains all "filing rights" with the transmission-owning utilities (both under utility-specific OATTs and under the SEEM market rules), which limits opportunities to consider the priorities of IPPs, consumers, state governments, or other stakeholders in updating FERC-approved rules of transmission of use and trade.
- The functionality of SEEM is limited compared to other regional market options. SEEM does not issue dispatch instructions, does not optimize generation dispatch, manage transmission congestion, or facilitate reserves sharing between its utility members. Parties to a transaction must take action on their own to finalize the sale. SEEM prices are trade-specific, which means, unlike in EIM or RTO markets, SEEM does not yield transparent real-time market prices at which non-utility members of the industry could transact.
- Trade volumes in SEEM have been limited in its first six months of operation, including certain days in which no power is traded among SEEM participants. SEEM's performance during

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31 For example, in the PJM RTO, emergency conditions in the Mid-Atlantic can be mitigated by excess generation in Illinois or demand response in Ohio. The tools available to the system operator feature more geographic and technological diversity, which tend to be less susceptible to shared points of failure.

Winter Storm Elliot has been criticized, as volume of cleared energy was negligible during the storm.[32]

- The governance of SEEM has been criticized on grounds that large utility members hold more control over SEEM than other market participants, and its governance would not meet the standards of inclusiveness and sectoral neutrality that FERC sets for RTOs.[33]

C. Joint Dispatch Agreement

DESCRIPTION AND RELEVANT CASE STUDIES

In a Joint Dispatch Agreement (JDA), the dispatch of all of the online generation of multiple utilities is pooled and optimized to serve their combined load. This pooling allows more efficient dispatch of generation across a wider fleet, which reduces costs. The JDA is the simplest of the wholesale market reform options available to South Carolina, and would be relatively expeditious to implement following development of consensus among member utilities, especially since Duke already runs a JDA for its two utilities. A JDA designates one utility to administer operations and dispatch, and settle net exchanges of electricity among the utilities (while stopping short of calculating public prices) so that cost savings can be shared. The JDA is both simple and a significant increase in functionality over SEEM, but the JDA's still-limited functionality (compared to other market reform options) means it offers the lowest net benefits to South Carolina of the wholesale reform alternatives evaluated here, and could even result in a net cost. The JDA only addresses near-term (and real-time) generation dispatch, which also provides some reliability benefits.

To illustrate the pooling benefit of a JDA, consider two utilities that each serve only their own demand. One utility may have only costly generation available to meet its demand, while another utility has surplus low cost generation. The customers of each utility would benefit by trading, the first utility produces less of its costly supply and buys the cheap surplus from the second

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32 See, for example, RTO Insider, "GCPA Panelists Go One on One Over SEEM Proposal", April 3, 2022; RTO Insider, "Southern Co. Takes Heat over SEEM, Opposition to RTO", May 16, 2022; S&P Global Market Intelligence, LLC, "Southeast Energy Exchange Market Addresses Reports of Limited Trading Activity", February 13, 2023.

33 As noted by FERC Commissioner Alison Clements in a recent dissent: "*NFEETS [Non-Firm Energy Exchange Transmission Service, a prerequisite of SEEMS participation] is only available to SEEM participants, and participation in SEEM is not open. Rather, a prospective participant must, among other things, execute enabling agreements with three counterparties who are already SEEM participants, and obtain the countersignature of the Participant Agreement by the SEEM Agent, who is controlled by an Operating Committee composed of SEEM Members*." Federal Energy Regulatory Commission, "Order Accepting Joinder Agreements and OATT Revisions," 181 FERC ¶ 61,275 in FERC dockets ER23-323, ER23-324, ER23-325, and ER23-338, issued December 30, 2022.

utility, while the second benefits from profitable sales of generation that otherwise would not have been utilized. Ultimately, these cost savings from trade are passed on to customers through fuel and purchased power cost adjustments in retail rates.

While such trades currently can also happen bilaterally under the Status Quo, there are significant frictions inherent in bilateral trading, as discussed in the status quo section above. By contrast, a JDA accomplishes an efficient trading outcome automatically (sending out a real-time dispatch signal to each generator) and using pre-determined settlement rules to share savings. There is no need to match individual buyers and sellers, negotiate a price, pay a fee (except the relatively low JDA administrative fee), reserve transmission, or even recognize and approve the transaction. This means trading frictions are significantly reduced within the JDA footprint. The JDA also includes provisions that set a uniformly low or zero charge for transmission utilization for real-time trades within the JDA. The JDA is therefore more efficient than a bilateral trading environment, even one that is enhanced by SEEM.

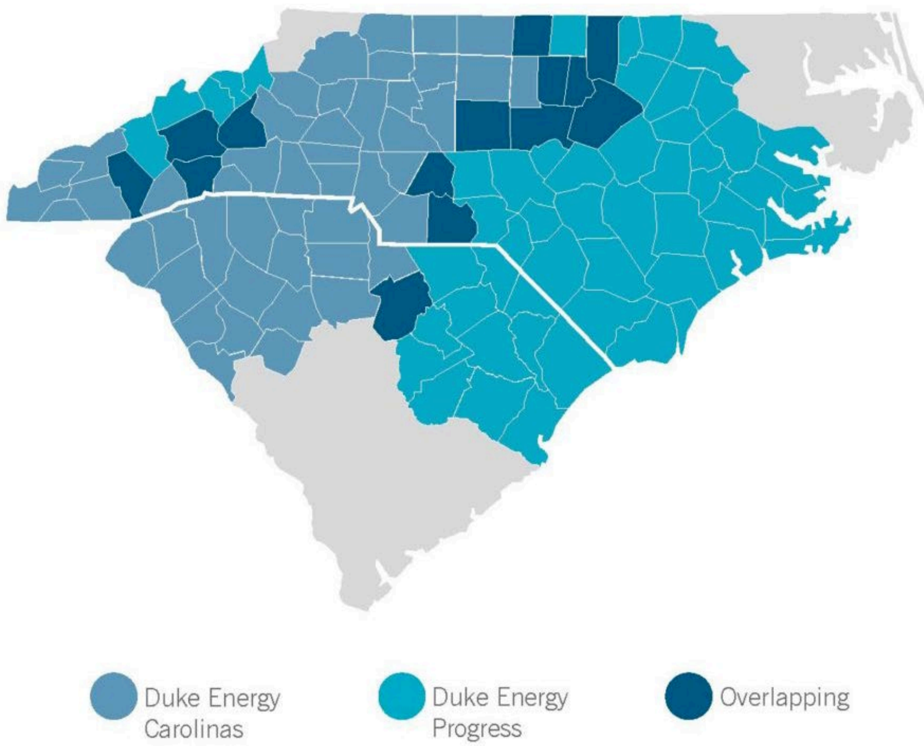
Since JDAs typically use only zonal representations of the transmission network, and cannot always optimize dispatch to the full transmission network availability, their efficiency in pooling online generation is not as effective as the more sophisticated transmission-security-constrained optimization used in the EIM or RTO options (discussed below). Further, the JDA (and the EIM) only pool generation that is online during real-time operations (after utilities have already prepared their day-ahead schedules for meeting their load by bringing generators online and offline). There are major additional efficiencies that are generated by optimizing the day-ahead scheduling process in an RTO setting. Under the JDA and EIM, trade that would require modified generation commitment is subject to the high-friction bilateral trading environment and is unchanged from the Status Quo. In an RTO (or an EIM that includes day-ahead commitment), by contrast, both the day-ahead and real-time generation commitment and dispatch function are optimized across the entire market footprint.

In most JDAs, the minute-to-minute load and supply balancing (i.e., the BA functionality and responsibility) is still conducted by individual utilities. Therefore, the JDA per se does not yield the cost savings and efficiency benefits of pooling operating reserves and consolidating BA functions. While the JDA and its designated operator have no formal reliability responsibility, they do assist with real-time operational reliability by increasing cross-utility liquidity and therefore also increase the options that are quickly available to dispatchers. In some cases a JDA is combined with consolidation of the JDA members into a single BA, in which case such pooling benefits do accrue.

JDA agreements are regulated by FERC and administered by the utility signatories. Other market participants within the JDA footprint (IPPs, distribution-only utilities, etc.) do not have a formal stake regarding the policies and governance of the JDA.

JDAs have been deployed in various contexts. Duke's utilities currently operate under a JDA spanning Duke Carolinas and Duke Progress in both North and South Carolina as shown in Figure 6. The Duke JDA includes only a single corporate parent, but cross-company JDAs also exist—such as with Xcel Colorado, Platte River Power Authority, and Black Hills Colorado Electric, which until recently operated under a JDA managed by Xcel (which also served as a common Balancing Authority).[34]

FIGURE 6: DUKE ENERGY JDA SPANS DUKE ENERGY TERRITORIES IN BOTH SOUTH CAROLINA AND NORTH CAROLINA.



Source/Notes: Duke Energy, "Economic Development—The Carolinas," accessed January 21, 2023.

POTENTIAL ADVANTAGES

The advantages of the JDA are:

- Reduces barriers to trade by automatically effectuating trades through centralized dispatch and pre-determined settlement and pricing rules

[34] In August, 2022, Colorado Springs Utilities left the JDA to join the SPP Western Energy Imbalance Service (WEIS). The remaining members plan to join WEIS in April, 2023, which will end their JDA.

- Limited geographic scope compared to the EIM and RTO options yields straightforward setup and administration.
- Since the JDA designates one of its members to operate it, there is no need to create, manage, and govern an independent entity. Achieving consensus among the limited number of members is simpler than in a larger market. Further, the flexibility afforded in developing the settlement price may help members avoid concerns about market power (and related administrative burdens, such as requesting market based rate authority from FERC).

POTENTIAL DISADVANTAGES

The limited functional and geographic reach of the JDA option results in several notable disadvantages:

- The net benefits are smaller than for the EIM and RTO options, which cover a larger set of functions and, typically, a larger geographic footprint.
- Without independent administration, members and other market participants may not be confident that conflicts of interest are resolved in an unbiased way (especially when the operator needs to make manual dispatch decisions). Further, members may need to provide market-sensitive data to the operator that could provide a competitive advantage to them (or require burdensome firewalls to prevent such advantage).
- Market prices are not established and posted publicly, thus foregoing the broader market advantages of transparent wholesale market pricing.
- Since the JDA governance is not managed through a formal stakeholder process and is limited only to the participating utilities, the arrangement is not as scalable as other market reform options.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Development of a JDA would proceed in three stages: negotiations among the members; regulatory approvals at the state and federal level; and implementation of software and business processes. The Xcel Colorado JDA, which took about three years from conception to operations, can provide an illustrative case study:

- Discussions among the members took several months (from mid to late 2014).
- The regulatory process took a little over a year (the first regulatory filings were submitted to FERC in October 2014, and FERC finally approved the JDA in February 2016).
- JDA operations commenced over a year later (on June 1, 2017).

Most JDAs are operated internal to a common holding company, and it is difficult to precisely estimate their administrative cost. [35] While their limited size means that annual costs are spread over relatively few customers (compared to other wholesale market reform options), their simplicity means those costs are relatively low. For the purposes of this assessment, we assume a low-end annual administrative cost of $2 million in $2022 as indicated by the $0.50 per MWh per transaction for the Colorado JDA in 2016 together with estimated JDA transaction volumes in South Carolina.[36] To account for the potential increased cost from the larger size of South Carolina's electrical system (roughly double the size of the Colorado JDA), we use a high end estimate of $4 million.[37]

D. Energy Imbalance Market

DESCRIPTION AND RELEVANT CASE STUDIES

Like a JDA, an Energy Imbalance Market (EIM) jointly optimizes the real-time output of generators from a number of utilities to meet their combined load (ideally across a wide, multi-state area).[38] However, the EIM introduces new features that extend beyond the JDA: (a) an independent entity to administer operations, with defined governance procedures; (b) publication of wholesale market prices at every location and for every 5-minute interval that are used to settle net exchanges of energy among utilities (or any independent generators); (c) more sophisticated nodal (security-constrained) optimization of dispatch making full use of available transmission; and (d) optimization of flexible real-time scheduling for quick-start generators. While the EIM, like the JDA, focuses on the real-time operating horizon, it still leaves the minute-to-minute balancing up to the individual utilities and/or Balancing Authorities. The EIM offers more functionality than a JDA, but it lacks important features of an RTO, and so offers lower net benefits than an RTO.

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35 The Xcel Colorado (aka Public Service Company of Colorado) JDA fee was $0.50/MWh per transaction in 2016. Note that the JDA charge for Xcel Colorado included recovery of capital costs. Source: Colorado Public Utilities Commission (CO PUC), Recommended Decision Of Administrative Law Judge Mana L. Jennings-Fader Granting Application In Part, Addressing Treatment Of The Joint Dispatch Agreement, Ordering Accounting Treatment, And Ordering Public Service To File Reports, Proceeding No. 16A-0276E, Page 15, November 30, 2016.

36 In our 2030 simulation scenario, South Carolina has a total of 90,370 GWh of annual load, and the JDA case had 2,564 GWh of transactions among members.

37 Guidehouse and Charles River Associates, "Southeast Energy Exchange Market: Market Benefits and Non-Centralized Costs Evaluation", November 18, 2020, Page viii.

38 The term "imbalance" refers to real-time deviations relative to the day-ahead and intra-day supply/demand balance and trades that were scheduled prior to real-time operations. Imbalance occurs when generators produce more or less energy than scheduled, or consumers use more or less energy than scheduled.

An EIM typically calculates and publishes prices for each location at 5-minute intervals. These prices (called "locational marginal prices" or LMPs) are formulated in essentially the same way as energy prices in an RTO. LMPs are closely related to the marginal cost to serve the next increment of load at a location. Inter-utility exchanges are effectively settled on 5-minute intervals using these prices and each utility is credited according to the output of their generators and the price at the corresponding locations, and likewise they are debited according to their consumption at each location times the price there. This pricing mechanism also results in congestion charges, with revenues that are refunded according to various sharing formulas.

An EIM can make full use of the transmission grid in formulating dispatch instructions, using a sophisticated nodal (security-constrained) optimization that considers the actual physical capabilities of the transmission network. This yields more efficient real-time pooling than a JDA. However, the EIM (like the JDA) option has the drawback of only optimizing the small portion of generation that is available for redispatch in real-time, after utilities have already prepared their day-ahead and hour-ahead schedules for meeting their own load—a significant loss in pooling benefits and functionality compared to an RTO. Finally, the EIM is like a JDA in leaving the minute-to-minute balancing up to the individual utilities (who typically are the Balancing Authorities), foregoing the benefits of consolidated BA operations and pooled reserves that an RTO provides.

The EIM does not generally have formal reliability responsibility; however, it does provide utility dispatchers with a larger range of options to react to real-time contingencies relative to the Status Quo. By having Security Constrained Economic Dispatch across the market footprint, imbalances are better managed by an EIM and it enables greater ability to manage real-time flows from a more diverse set of resources (both supply and demand side). Additional reliability benefits include enhanced situational awareness of the system; potentially fewer emergency events; faster identification, dispatch, and delivery of replacement generation after shared contingency reserves are depleted and when contingencies are encountered beyond reserve obligations; and greater integration of variable energy resources.[39]

Policymakers with extended reform timelines can view the EIM as an incremental step in the gradual development of an RTO, as illustrated by history. In SPP, the RTO's members first formed an EIM-style market in 2007 and, after realizing the operational benefits under a full RTO market

[39] Federal Energy Regulatory Commission, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market, Staff Papers, February 26, 2013.

structure, in 2014 expanded functionality to include a day-ahead energy market.[40] A similar pattern may be playing out now again in the West. The California Independent System Operator (CAISO) and Pacificorp started the Western EIM (WEIM) in 2014, which has since expanded geographically to cover much of the West. CAISO and Pacificorp have most recently committed to add day-ahead functionality to WEIM through an Extended Day Ahead Market (EDAM).[41] Relatedly, the Mountain West Transmission Group of utilities, formed in 2013 to explore pooled operations, effectively evolved into the Western Energy Imbalance Service (WEIS), a standalone EIM operated by SPP that was launched in 2021.[42] SPP and the WEIS members later initiated ongoing discussions to convert much of WEIS into a new Western RTO, while SPP has simultaneously proposed a new "Markets+" non-RTO construct in the West that would include a day-ahead market.[43]

The Western examples show that an existing RTO can offer EIM functionality to utilities outside the RTO. Under such a scenario, utilities outside the RTO can also pool real-time operations with the RTO (but without joining the RTO). The WEIM today has almost twenty member utilities representing 79% of the load in the Western Interconnection, with annual savings approaching $1 billion (see Figure 7 below), and a day-ahead construct called the Extended Day-Ahead Market (EDAM) is being developed, with go-live targeted for 2024.[44] The EDAM is estimated to yield $543 million in operational savings in addition to today's savings from WEIM. Given the EIM benefits experienced in the West, CAISO and SPP are both working with non-member utilities to explore expansion into a multi-state RTO, and Nevada and Colorado have mandated that their utilities join wholesale markets.[45]

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[40] CAISO, ERCOT, and PJM likewise launched with only real-time markets (albeit with consolidated balancing areas, unlike SPP) before they initiated day-ahead markets. SPP operated across several balancing authorities as an RTO with only real-time energy markets (analogous to an EIM structure) from 2006 until 2010, when the utilities consolidated under SPP as a single Balancing Authority. Federal Energy Regulatory Commission, "SPP—Federal Energy Regulatory Commission," accessed February 16, 2023.

[41] For example, see American Public Power Association, "PacifiCorp Agrees to Join California ISO's Extended Day-Ahead Market," December 13, 2022.

[42] Mountain West Transmission Group, "Frequently Asked Questions," updated January 5, 2017; J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020; SPP, "WEIS – Southwest Power Pool," accessed February 16, 2023.

[43] J. Tsoukalis, E. Bennett, Benefits of the SPP RTO Expansion into the WEIS Footprint, The Brattle Group, September 20, 2022; SPP, "RTO West—Southwest Power Pool," accessed February 16, 2023; SPP, "Markets+ – Southwest Power Pool," accessed February 16, 2023.

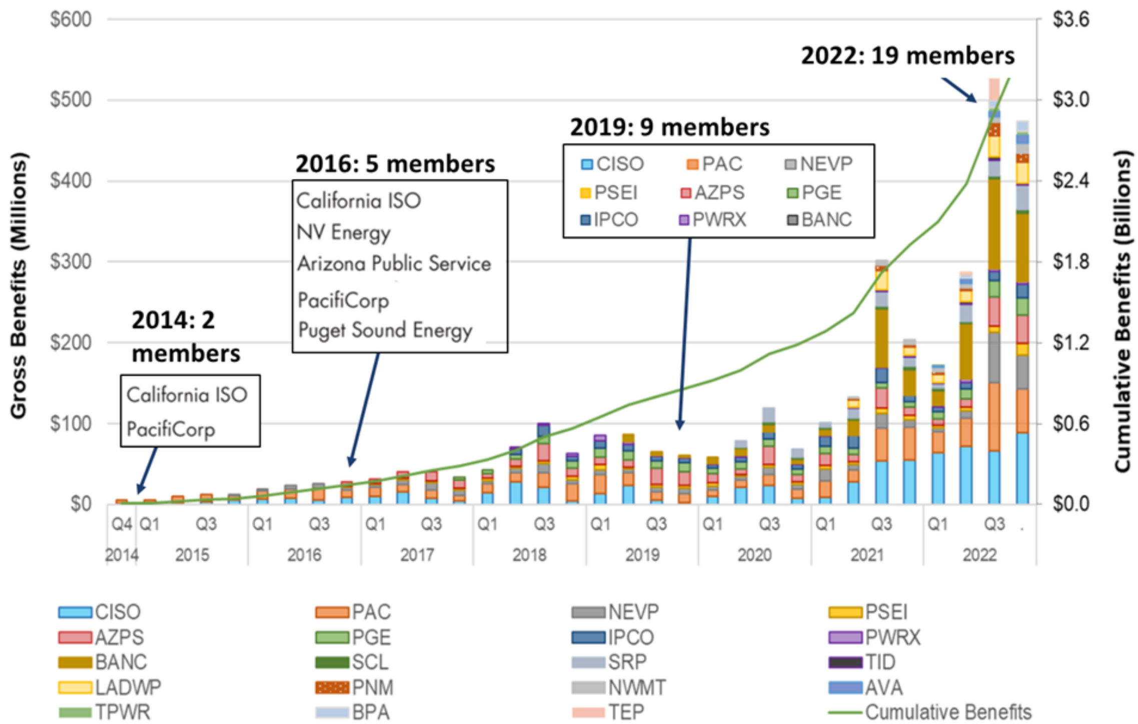
[44] CAISO, "EDAM: Extended Day-Ahead Market," accessed February 16, 2023.

[45] D. Hurlbut, et al., Impacts of Expanded Regional Cooperation on California and the Western Grid, National Renewable Energy Lab, January 13, 2023; SPP, "Markets+—Southwest Power Pool," accessed February 16, 2023.

As noted, there are currently two EIMs in operation in the United States: the CAISO-run Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). In each case, significant production cost savings are evident (for example, see Figure 8 below). In justifying their approval of participation in the WEIM and WEIS, state commissions cited operational efficiencies from pooled dispatch, benefits in reducing the need for certain reserves products, improved integration of low-cost renewables, and expanded options for achieving reliability.[46] WEIM also claims reductions in carbon emissions associated with reduced curtailments.

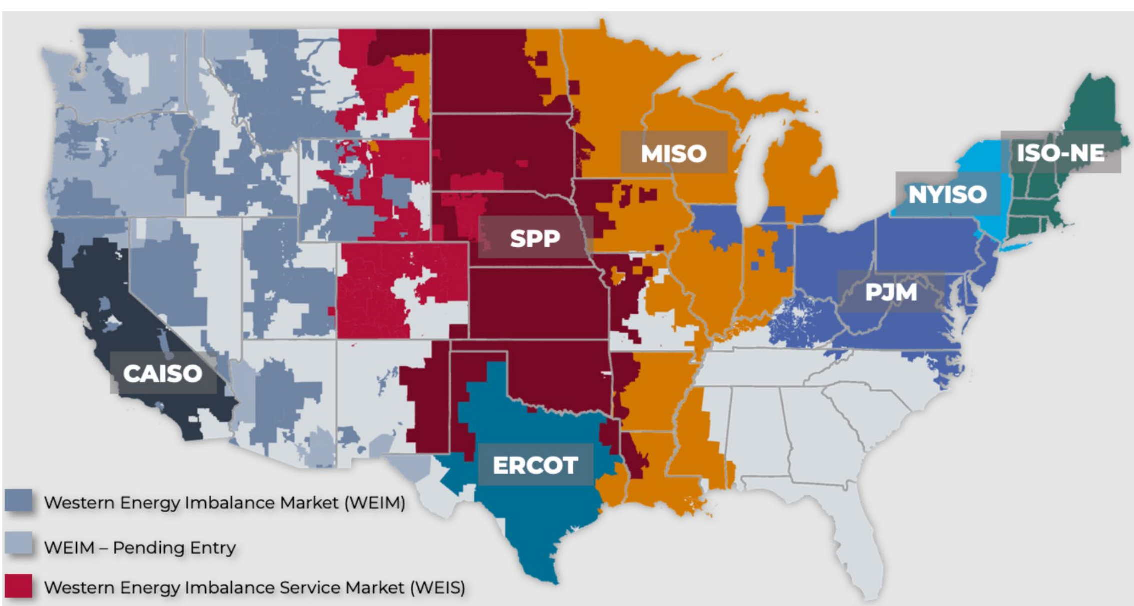
46 For example, see state commission orders accepting aspects of EIM participation in: Nevada Public Utilities Commission, Docket 14-04024, August 27, 2014; Arizona Corporation Commission, Docket E-01933A-20-0039 Decision 77746, September 22 and 23, 2020; and Idaho Public Utilities Commission, Order 33627 Case IPC-E-16-19, January 31, 2017.

FIGURE 7: BENEFITS OF WESTERN ENERGY IMBALANCE MARKET GREW EXPONENTIALLY WITH INCREASED MEMBERSHIP



Source/Notes: Western EIM, "Western Energy Imbalance Market Benefits: Fourth Quarter 2022," January 31, 2023.

FIGURE 8: CAISO'S WESTERN ENERGY IMBALANCE MARKET AND SPP WESTERN ENERGY IMBALANCE SERVICE IN THE CONTEXT OF RTOS



Source/Notes: Note that light blue areas listed as "pending entry" are currently operating as part of WEIM. Clean Energy Buyers Association, "Organized Wholesale Electricity Markets," 2022.

EIMs potentially span many utilities and states, and so they face some of the same governance requirements as an RTO. Therefore, their governance is carefully designed to facilitate independent policymaking, to give all stakeholders a voice, and to ensure independence from any one member or sector. The EIM entity itself has “filing rights” over the rates, terms, and conditions in its tariff on file at FERC.

As illustrated by the JDA and EIM cases described above, utilities often consolidate their operations to enjoy the benefits of pooled operations without forming an RTO. Such pooling also can be accomplished in a peer-to-peer collaboration with RTOs. For example, CAISO’s Western EIM is a conventional EIM structure that is also an operational extension of the existing CAISO RTO real-time energy market, and shares many of its energy market features.[47] The EIM utilities enjoy the operational benefits of pooling with CAISO’s real-time energy market without actually joining the RTO as members.

Resource adequacy consolidation is also possible (although no RTO is currently part of such services), as illustrated by the nascent Western Resource Adequacy Program.

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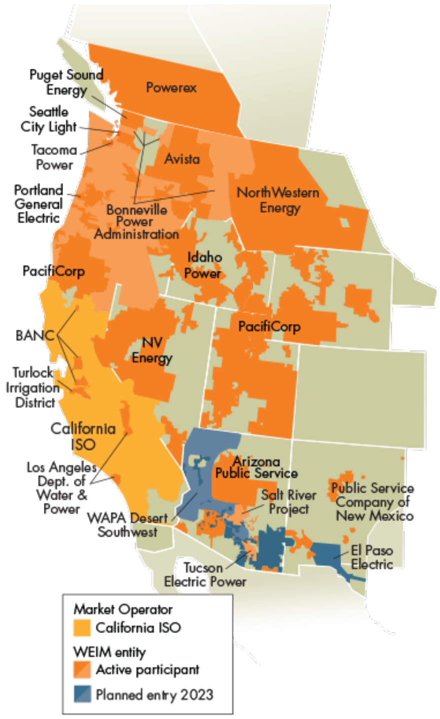
47 While CAISO is technically an Independent System Operator (ISO) and does not meet FERC’s current governance criteria to be an RTO, we will refer to it as an RTO for the purposes of this section.

FIGURE 9: CAISO'S CONSOLIDATED EIM SERVICE OUTSIDE ITS RTO (LEFT) AND THE POOLED WESTERN RESOURCE ADEQUACY PROGRAM (RIGHT)



Source: CAISO, "[About—Western Energy Imbalance Market](#)," 2023; Western Power Pool, "[Western Resource Adequacy Program—WRAP Area Map,](#)" 2021. Both accessed February 11, 2023.

South Carolina could initiate discussions with PJM in pursuit of a similar approach of consolidating energy market and resource adequacy functionality without becoming full RTO members. This approach yields the benefits of pooled functionality without subjecting every aspect of wholesale operations to regional and FERC governance. The functions that could be consolidated with PJM:

- **Shared resource adequacy:** following the example of the Western Resource Adequacy Program (WRAP, pending filing with FERC, administered by SPP but not consolidated with it), South Carolina could pool resource adequacy requirements with other areas (including potentially PJM), thereby yielding significant investment savings. This function is made simpler by consolidating dispatch and scheduling of generation across the same area to effectuate the potential resource adequacy needs in actual operations.
- **Consolidated EIM**: following the example of WEIM, this would jointly optimize just the real-time energy market between South Carolina and PJM. This yields savings when real-time operations deviate from the day-ahead scheduling plan.
- **Consolidated day-ahead energy market**: this would follow current plans to extend WEIM ("EDAM") and WEIS ("Markets+") to include a day-ahead generator scheduling function. Pooling generator schedules yields major savings in fuel costs.

POTENTIAL ADVANTAGES

The potential advantages of an EIM are:

- **Operating efficiency** that is achieved by pooling real-time dispatch across many utilities and removing barriers to efficient trade. In the real-time operating horizon, a utility that can more cheaply buy from other members rather than self-generating is automatically dispatched to that outcome with minimal friction. The reverse is also true for utilities that can cheaply produce excess power. The EIM also removes some "pancaked" transmission rates within its footprint, further reducing trade friction.
- **Transparent prices** provide public benchmarks for planning and bilateral trades at every time horizon, from hourly and day-ahead to long-term PPAs.
- **Increases ability for consumers, public power, and independent power producers to engage in voluntary transactions** in real-time at transparent prices and with equal access to the transmission system.
- **Independent administration and governance** means no one utility or other member is advantaged in the administration of the system. Natural conflicts of interest in utilization of transmission and generation are resolved programmatically in favor of economic efficiency, rather than in favor of the interested party who is operating the system. The rules according to which the independent administrator acts are themselves subject to a consensus-building and decision-making governance process, regulated by the FERC.
- The **relatively simple functionality** of an EIM compared to an RTO makes it easier and lower cost to launch an EIM (both in terms of consensus building and business-process implementation), and easier to reverse course if the benefits fail to materialize. EIM can therefore offer an incremental first step towards greater regional integration. If South Carolina took this initial step to create an EIM (e.g., with other SEEM members) and benefits prove to exceed costs in the first years of EIM operations, state policymakers could then consider taking steps to additional wholesale market reforms.[48]

[48] There is precedent for this approach in other jurisdictions. For example, when Dominion Virginia/North Carolina joined PJM, the Virginia regulator required the utility to analyze benefits and costs each year and report to the regulator. Similarly, the WEIM publishes benefits and costs each quarter, and SPP published benefits of its transition from an EIM-style market to an RTO. See Dominion Energy, "Dominion Applies to Join PJM Interconnection", June 27, 2003; Western Energy Imbalance Market (WEIM), Western Energy Imbalance Market Benefits Third Quarter 2022, October 31, 2022; and SPP, 2021 Member Value, April 6, 2022.

POTENTIAL DISADVANTAGES

Potential disadvantages of an EIM include:

- An EIM lacks several key aspects of the functionality of an RTO, and so foregoes the value achieved from scheduling generators via pooled day-ahead unit commitment, provision of centralized ancillary services, balancing area consolidation, and regional transmission planning.
- The functionality of the EIM is less than that of an RTO, while the implementation complexity of creating a new EIM is greater than joining an existing RTO (since, unlike in the West, the EIM membership option is not already available from RTO market operators).

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

As with other wholesale market reforms, implementation of an EIM can be split into consensus-building and development of founding governance agreements; regulatory approvals; and business process implementation.

Because there is no existing EIM that South Carolina utilities can join, South Carolina's primary options are to develop a new EIM in the Southeast, or to partner with PJM to form a new EIM that is consolidated with a neighboring RTO. In the former case, the membership could save cost and implementation time by subcontracting with an existing RTO (such as SPP, MISO, or PJM) to host the operational infrastructure, as the WEIS has done with SPP. Forming a Southeast EIM could be a practical solution assuming that neighboring utilities and their regulators in nearby states such as North Carolina, Tennessee, and Georgia were willing to commit effort to pursuing the approach. As part of the present assessment, we evaluated the net benefits of an EIM with the same footprint as today's SEEM, but recognize that an EIM could start out with a smaller footprint.

Recent EIM development efforts have leveraged existing RTO systems to deploy at relatively low cost. The WEIM implementation cost was estimated at $20 million, while WEIS was estimated at $9.5 million.[49] Less recently, SPP's initial 2007 implementation of an EIM cost $33 million.[50]

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[49] CAISO, "Re: California Independent System Operator Corporation Filing of CAISO Rate Schedule No. 6488," January 29, 2021, Page 3, Docket ER-21-1003; Federal Energy Regulatory Commission, "Order Accepting Proposed Tariff", 173 FERC ¶ 61,267, Docket No. ER21-3-000, issued December 23, 2020.

[50] SPP, "Markets+ Proposal", November 30, 2022.

Today, WEIM covers nearly 80% of the WECC and has a $15.3 million annual budget.[51] WEIM has a similar size to the Southeast. WEIM could therefore be comparable in operations and cost to an EIM for the Southeast that, like WEIM, is operated by an existing RTO, thus offering economies of scale and minimal setup cost. We take the WEIM budget as an approximate indication of the potential low end of administrative costs for a Southeast EIM, with South Carolina's 13% share of costs totalling $2 million.[52] The WEIS annual budget of $5 million covers a load somewhat smaller than South Carolina, and can serve as an indicator of the approximate high end of the range of potential EIM administrative costs, particularly in scenarios in which South Carolina starts an EIM that is initially smaller.[53]

The West has been exploring greater regional coordination for decades, including consolidating balancing areas, implementing JDAs, shared reserves agreements, and other such arrangements. In fact, EIM discussions in the West among state governments, utilities, and industry experts started in earnest in 2011.[54] Those discussions laid the groundwork for the development and growth of the two current EIMs, WEIS and WEIM. These provide instructive case studies for the implementation timeline to roll out an EIM, as summarized in Table 4. The timeline is split into regulatory approvals (at both the federal and state level, although only FERC filings are referenced in the historical record) and business process implementation.

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51 CAISO, "Confidential Position Specification: Independent Non-Executive Governing Body Member (WEIM)", March 2023, Page 4.

For WEIM budget, see: CAISO, "2023 Budget and Grid Management Charge Rates", December 2022, Page 37.

52 By share of Southeast coincident peak. See Appendix A, page A-2.

53 SPP, "Western Joint Dispatch Agreement," 2019;

SPP, "Benefit Of The Market: Western Energy Imbalance Service (WEIS)", March 27, 2023, Page 8.

54 Milligan, M, et al., Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection, NREL, March 2013.

TABLE 4. TIMELINES FOR LAUNCH OF WESTERN EIM AND WESTERN EIS

	WEIM	WEIS
Consensus building and initial agreements	Close to two years: • First conceptual proposal in March, 2012 (following sustained discussion among state commissioners, governors, and the WECC in 2011)[55] • First straw proposal in April, 2013 • Draft tariff language finalized January, 2014	Close to one year: • First conceptual proposal published in June of 2019[56] • First participation agreements with members in September, 2019[57] • Draft tariff language finalized September, 2019
Regulatory approvals	About one and a half years: • Initial implementation agreement filed in March, 2013 • EIM rules filed with FERC on April 16, 2014 • Final approval in October, 2014[58]	About 10 months: • EIS Tariff filed with FERC on February 21, 2020 • FERC approval on December 23, 2020
Business process implementation	About one and a half years: • Implementation began February, 2013[59,60,61] • EIM operations launched November, 2014	About one and a half years: • Project initiated September, 2019 • EIS operations launched February, 2021[62]

E. Regional Transmission Organization (RTO)

DESCRIPTION, RELEVANT CASE STUDIES, AND STUDY SCENARIOS

A Regional Transmission Organization (RTO) is an independently governed and administered entity that executes several key functions on behalf of its member utilities, essentially pooling all wholesale functions: (a) reliably operating the BAA with optimized scheduling and dispatch of generators and demand response within transmission limits; (b) ensuring members have enough generation installed to meet demand effectively all the time ("resource adequacy"); (c) providing

55 CAISO, CAISO Response to Request from PUC-EIM Task Force, March 29, 2012.

56 SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service Market (WEIS), 2019.

57 S&P Global Intelligence, LLC, "Three regional utilities announce decision to join Southwest Power Pool market," accessed January 24, 2023.

58 Federal Energy Regulatory Commission, Order on rehearing, clarification, and compliance re California Independent System Operator Corporation, Docket No. ER14-1386-001, October 20, 2014.

59 CAISO and PacifiCorp, Energy Imbalance Market Memorandum of Understanding, February 12, 2013.

60 CAISO, Energy Imbalance Market Draft Final Proposal, September 23, 2013.

61 Federal Energy Regulatory Commission, 143 FERC ¶ 61,298, Docket No. ER13-1372-000, issued June 28, 2013.

62 SPP, "Western Energy Imbalance Service Market (WEIS)," accessed January 23, 2023.

regional coordination of transmission planning; and (d) development of market prices for energy and ancillary services. These functions are interrelated: the resource adequacy function is enforced through availability in the daily and real-time generator scheduling procedure, and pooled resource adequacy is made more robust through pooled BA operations and generation optimized dispatch; regional transmission planning is more effective than utility-specific transmission planning; and transparent market pricing for energy and ancillary services means that utilities and market participants readily understand the cost of serving their load with generators from another utility, and vice versa.

Like an EIM operator, an RTO is an independent entity that optimizes generator output for the benefit of the entire region, making best use of available transmission capabilities, and settling any net energy excess/shortfalls of members using a public and transparent energy price. The added functionality of an RTO (pooled day-ahead generator commitment and scheduling, resource investment planning, and regional transmission planning) significantly increases the net benefit of an RTO relative to an EIM, even taking into account the potential for higher administrative costs.

RTOs also create a more diverse region across which to calculate total capacity and reserve margin needs. By being able to determine total capacity or reliability requirements across a larger area, the RTO footprint can benefit from the inter-utility supply and demand diversity to reduce the capacity requirements for all customers while ensuring the same level of reliability and resource adequacy. Based on the total RTO capacity requirement, each utility or load-serving entity must then meet their share of total capacity needs and ensure that a minimum level of the capacity is located within their respective locations on the grid due to regional transmission limits. These lower RTO-based capacity requirements can then be met through integrated planning and self-supply (this option is available to vertically integrated utilities in all RTO markets), or by relying on the centralized RTO capacity market (where those exist and are sufficiently robust). The capacity market approach uses a forward competitive auction structure to secure the volume of needed capacity commitments from all qualified sellers, selecting the lowest-cost capacity suppliers first and ensuring transmission constraints are observed.

With transparent wholesale power prices, clear settlement mechanisms, and independent regional transmission administration and planning, RTOs provide a platform to enable competition and maximize use of the transmission system. State regulators in regions that participate in RTOs have the option (but not requirement) to rely more or less heavily on wholesale market price and competition to drive the investment choices of their utilities, public power, and consumers. The transparent prices that an RTO makes available also provide a useful benchmark for utility investments. Should South Carolina wish to pursue more competitive generation or retail supply (as discussed in Sections III and IV of this report), RTO participation provides a useful platform for enabling either or both of those. Such competition provides additional substantial benefits to the state. As discussed further in Section III.E below, an important and valuable feature of RTOs is their regional transmission planning process that is integrated throughout the region (and coordinated with neighboring regions). This serves to further enhance regional markets while lowering costs to consumers and improving reliability, among other benefits.

Since their introduction in the 1990s, RTOs have assisted utilities in successfully lowering the cost of wholesale power. RTOs have grown to include the majority of the United States as shown previously in Figure 8.[63] The hallmark of an RTO is independent coordination of many members across a wide area, often spanning many states. Most RTO customers are in RTOs that span many states. We study two such options in our market simulation modeling: South Carolina (and the portions of Duke Energy in North Carolina) in a new Southeast RTO with the footprint of today's SEEM, and South Carolina (plus Duke Energy in North Carolina) joining PJM. There are three single-state RTOs: California, Texas, and New York. These states are large, they rank first, second, and fourth in population in the United States and due to their size, they can extract much of the benefit of an RTO without the need to coordinate with other states. South Carolina is not as large, thus critically limiting the value a South Carolina-only RTO could provide. Therefore, we did not study a single-state RTO for South Carolina.

The many functions of an RTO provide direct benefits in the form of operational savings and reduced need for installed generation or other resources (or higher reliability from the same sized fleet), with the additional benefit of more efficient regional transmission planning. These three functions complement and augment each other. While most states with an RTO-member utility use a vertically integrated regulation model, an RTO is also a prerequisite for scalable and robust competition in production and supply of electricity for states that choose to pursue such methods. As shown in the next section (Section III), such competitive reforms are themselves a potential source of significant benefits for South Carolina consumers.

RTO Governance and Regulation: Broader regional coordination necessarily entails less autonomy in setting the rules of access for the transmission system (currently proposed separately by each utility under FERC oversight of their respective OATTs) and greater

[63] Not shown are the three Canadian provinces Alberta, Ontario that have their own RTO, and Manitoba, which is a part of MISO.

cooperation and compromise among all members and stakeholders. In an RTO, that compromise is negotiated through its governance.

RTOs, including single-state RTOs, operate high voltage transmission lines that functionally interconnect many states, and administer wholesale transactions in interstate commerce. Therefore they are regulated by the Federal Energy Regulatory Commission (FERC). FERC has issued two landmark orders regarding RTO governance. Order 888 (and its lesser companion order 889), issued in 1996, created the concept of Independent System Operators and a framework for their governance.[64] Order 2000, issued in 1999, did the same for the Regional Transmission Operator concept, an updated take on the ISO.[65] While these orders lay out high-level governance expectations, including board composition and principles for the stakeholder process, nonetheless FERC has been flexible in approving diverse governance structures, as discussed above.

While RTOs have been found to yield large net benefits by leveraging an extensive set of pooling functions, their governance varies both across the RTOs and even within an RTO according to function.[66] For example, transmission cost allocation policies are generally governed by a committee of transmission owning utilities; energy market rules are typically governed by the RTO board, with input from members; day-to-day dispatch authority comes directly from NERC-defined roles via federal legislation.

Two features of RTO governance are prominent: (1) the allocation of OATT "filing rights" and RTO operational activities among the RTO, the RTO Board, its members, and states, which can vary according to policy matters, specific infrastructure investments, and day-to-day decisions; and (2) the voting structure and relative sectoral power of the members within the stakeholder process. Finally, the legal and regulatory environment of RTO-related precedents at FERC and the courts ultimately constrains what RTOs can do within their governance. In addition, the extent to which governance is effective in representing the interests of individual states depends on the uniformity (or diversity) of participating states and market participants. In RTOs with more uniform market participants and participating states (such as SPP, with vertically integrated member states and utilities) governance and consensus building will tend to be easier than in RTOs with a very diverse set of states and market participants.

[64] Federal Energy Regulatory Commission, "History of OATT Reform," accessed February 11, 2023.

[65] K. Costello and R. Burns, "Regional Transmission Organizations and the Coordination of Regional Electricity Markets: a Review Of FERC Order 2000," The National Regulatory Research Institute, April, 2000.

[66] See Table 8 for a summary of other studies of RTO benefits.

Allocation of authority: Most RTOs have plenary authority over their own rates and policies on file at FERC, known as OATT "filing rights."[67] FERC precedent suggests this is the expected structure of RTO authority, though the RTOs can incorporate stakeholder and state regulatory bodies into formal approval processes that must be passed prior to proceeding with filings to update the prevailing OATT. RTOs also feature an organized stakeholder process to inform or act as a precondition to filing RTO Tariff changes. These stakeholder processes are generally structured with tiers and sector-based voting to produce a final advisory decision, with the RTO holding an important agenda-setting role.

Among RTOs, there are numerous variations on the RTO governance structure, such as:

- In PJM, many rule changes related to energy markets, ancillary services markets, settlements, and various other matters must be approved by members through the stakeholder process in order to be filed under the ordinary process.[68]
- ISO New England is obligated to file policy proposals that meet a minimum stakeholder vote threshold alongside its own corresponding proposal.[69]
- As noted below, states in SPP participate in a governing body that holds an approval role over certain major policy areas such as resource adequacy and transmission cost allocation.

These regional variations partly reflect the historical interests of parties involved in forming the initial RTO and its governance structure. Such parties sought the benefits of the RTO, but were interested to maintain a share of authority over the direction of their RTO's future. For example, SPP and its state regulator constituents sought to reserve to the states a more significant share of authority, and so SPP proposed (and FERC approved) a Regional State Committee with authority over major portions of the SPP Tariff.[70] The Regional State Committee is composed

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67 That is, they have the right to file changes to their Tariff as the corresponding utility under Section 205 of the Federal Power Act. FERC is required to approve such changes as long as they are just and reasonable. For a detailed accounting of RTO governance, see C. Parent, et al., "Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs," Exeter Associates, Inc., prepared for New England States Committee on Electricity (NESCOE), February 2021.

68 Namely, rules that are currently described in the PJM Operating Agreement, over which only the PJM membership holds 205 filing rights.

69 The minimum vote threshold is 66% sector-weighted vote at the Participants Committee for non-market rule changes and 60% vote for market changes. See Section 3.3 of C. Parent, et al., "Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs," Exeter Associates, Inc., prepared for New England States Committee on Electricity (NESCOE), February 2021.

70 The Regional State Committee concept was initially developed by FERC as part of its Standard Market Design Effort. See FERC, White Paper Wholesale Power Market Platform, Docket No. RM01-12-000, April 28, 2003.

entirely of state regulators, and has autonomous rights to file all policy proposals related to resource adequacy, cost allocation related to transmission upgrades, and allocation of transmission congestion surplus (also called "financial transmission rights").[71] See Table 5 below for examples of different ways that RTOs divide their authority among states, stakeholders, and RTO staff and their boards. These regional variations illustrate FERC's flexibility in approving diverse approaches to RTO governance.

RTOs can ultimately authorize funding for investments in transmission (and in some limited cases generation as well).[72] For example, the regional transmission planning process that is common to RTOs results in proposed transmission upgrades (including substation improvements, minor or major upgrades to existing transmission lines, and potentially running new transmission lines). Today, specific transmission investments in RTOs are mainly approved by the RTO board. However, approval processes do vary today, and greater variation may well be possible in the future. While there is no precedent for states to have approval or veto authority over RTO decisions regarding specific transmission investments, and it is unclear whether FERC would approve such a structure, it is nonetheless conceivable.

In traditionally regulated states that are in RTOs, market outcomes (including in a capacity market construct) do not drive investment decisions. States are able to retain a vertically integrated utilities structure and retain full authority to oversee resource investments through IRPs. RTO prices serve to incentivize efficient operations, may result in trades that yield savings for the utility and its customers, and can act as transparent pricing indicators that are useful in the IRP process. In PJM for example, utilities can opt out of the capacity market altogether, removing their supply and demand from any financial interaction with market outcomes.[73] By contrast, in restructured states, RTO market outcomes also incentivize generator (and other resource) investment from private market participants. In that sense, the RTO market rules, especially capacity market rules, ultimately drive investment decisions in restructured states. Those rules are managed through the policymaking process discussed above.

The day-to-day business of the RTO is generally governed by the Tariff and business practice manuals that contain more granular detail. Operations protocols in the dispatch room are often

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71 Hinton, Justin A., and the Southwest Power Pool Legal Department, The History of the Regional State Committee for the Southwest Power Pool, Inc., SPP, April 2022.

72 Namely, RTO-authorized "reliability must-run agreements" that fund generators which are needed to maintain system reliability, especially based on local constraints.

73 The "Fixed Resource Requirement" or FRR option. See PJM, Securing Resources Through the Fixed Resource Requirement, September 23, 2022.

dictated by NERC standards as delegated to Reliability First Corporation (in the case of PJM) or to SERC (in the case of South Carolina and other Southeast utilities), since RTOs generally exercise operational authority through formal NERC roles such as Reliability Coordinator, Balancing Authority, and Transmission Operator. These roles are currently fulfilled in South Carolina by VACAR (administered by Duke) as NERC-designated Reliability Coordinator (RC) and the individual utilities as NERC-designated BA and Transmission Operator (TOP).

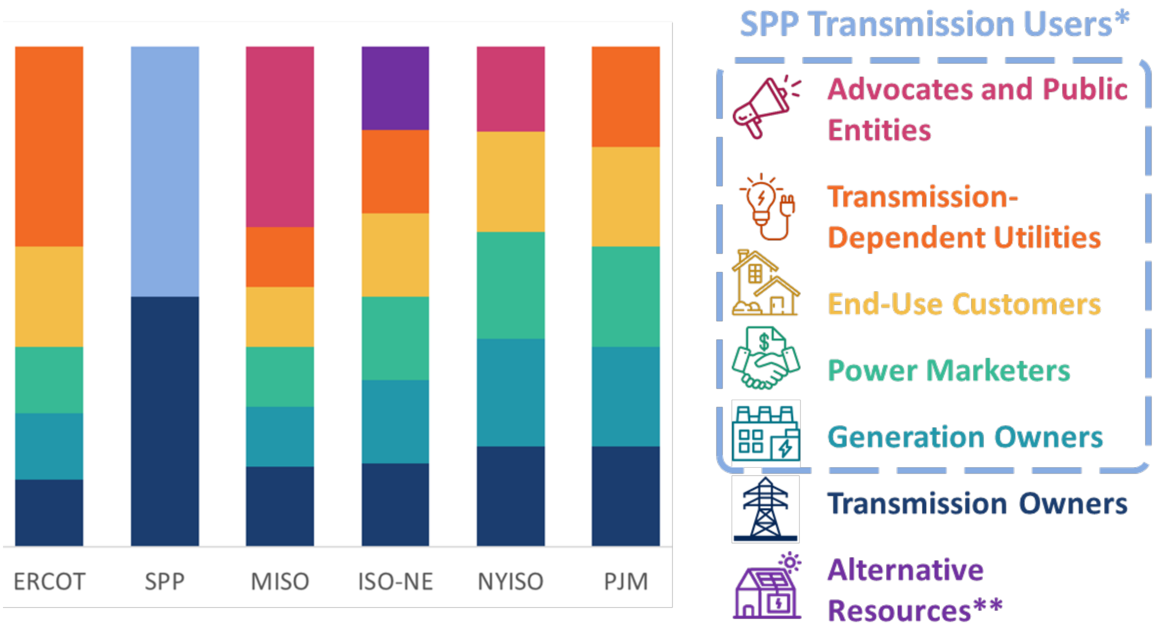
TABLE 5. SOLUTION OPTIONS FOR APPROVER ROLES OF VARIOUS RTO PROTOCOLS

	Status Quo w/out RTO	**Examples of RTO Approval Processes Currently In Use**	
Resource Adequacy: Resource Mix	*State regulator*	Vertically integrated (with or w/o capacity market): state IRP	Deregulated w/capacity market: RTO Board (as amended by state subsidies)
Resource Adequacy: Installed Reserve Margin Requirement, Accreditation, Allocation of Obligations, etc.	*State regulator*	• States committee authorizes all resource adequacy functions (SPP) • State approval for IRM (NY, CA) and allocation of obligations (CA) • State override (IRM in MISO)	RTO board or staff
Transmission Cost Allocation/Rate Method	*N/A*	States Committee (SPP)	RTO Board or utility-only committee (PJM)
Transmission Rates for a Transmission Owning Utility	*FERC*	Filed by utility, approved by FERC	
Approve Specific Regional Transmission Projects	*State*	States committee (not current implemented in U.S.)	RTO Board, or RTO Board as well as members (SPP)
Allocation of Congestion Surplus ("Financial Transmission Rights," FTRs)	*N/A*	States committee	RTO Board
Generation Interconnection Procedures	*Utility*	Utility specific technical details (widespread) or cost allocation (pending in PJM)	RTO Board
Market and Operational Rules	*N/A*	RTO Board or RTO Board together w/ Members (PJM)	

Stakeholder voting structure: RTO stakeholders consist of transmission owners (i.e., large utilities), market participants (i.e., users of the transmission system), and public representatives. Each RTO hosts a structured stakeholder process that, through voting, can produce advisory policy decisions (informative both to the RTO itself as well as to FERC in its ultimate approval authorities) or in some cases impose a threshold for Tariff revisions. RTOs deploy a sector-weighted vote at the final decision stage, with each member obligated to choose a single sector. Vertically integrated utilities are often assigned the transmission owner sector. Figure 10 illustrates the allocation of votes among the sectors. End-users, transmission-dependent utilities (e.g., municipal and cooperatively owned utilities), and public entities all tend to represent consumers. Representation of this customer group varies somewhat, with greater power in MISO and ERCOT.

Transmission owners represent a unique constituency in the context of RTO voting and governance. Federal "open access" policy has long sought to ensure that all generators and consumers have fair and equal access to the transmission system, and ensure that the transmission owners and their affiliates are not able to privately gain by implementing rules, processes, or rates that intentionally or unintentionally limit competitors' access. Without an RTO, the primary means of ensuring such access is through FERC oversight that seeks to ensure fair rules of access are incorporated into each transmission owners' OATT. Under an RTO structure, the transmission owners must work through the same stakeholder processes as other entities and within their own voting share to achieve desired updates to the RTO OATT.

FIGURE 10: RTO STAKEHOLDER VOTING RIGHTS BY SECTOR



Source/Notes: S. Lenhart and D. Fox, [Participatory democracy in dynamic contexts: A review of regional transmission organization governance in the United States](), Energy Research & Social Science, Volume 83, January 2022.

* Transmission users in SPP includes utilities with no more than 500 miles of meshed transmission lines operated at above 60 kV.

** ISO-NE considers renewable generation, distributed generation, and load response as "alternative resources." Other RTOs include these resources in Generation Owner or End-Use Customer segments.

POTENTIAL ADVANTAGES

The potential advantages of joining an RTO are:

- Net benefits that significantly exceed those offered by the status quo and other wholesale market reforms considered here.
- A well-established framework with straightforward legal and technical implementation (most straightforward if pursuing membership in a pre-existing RTO).
- Improved operational tools for reliably and cost-effectively serving load and integrating solar and wind.
- Improved coordination among utilities in South Carolina (and with utilities in neighboring states) in operations and planning.
- Increased ability for consumers, public power, and independent power producers to engage in voluntary transactions at transparent prices and with equal access to the transmission system.

- Provision of regional transmission planning to improve efficiency, reliability, regional integration, and access to lower cost and cleaner resources (discussed further in Section II.F below).
- Can provide a turnkey option for incremental advances in retail choice (if desired by South Carolina policymakers), potentially attracting new industries and customers that can prompt economic development, while also providing more alternatives and potential savings for existing large customers including municipal and cooperative utilities
- Can serve as a platform for competitive generation investments (if desired by South Carolina policymakers).

POTENTIAL DISADVANTAGES

The potential disadvantages of joining an RTO are:

- For functions performed by the RTOs and market rules: requires compromises to achieve consensus with other states, utilities, and other stakeholders of the RTO through the governance process. Functions retained by the utilities, state regulators, and state governments, such as resource planning, local reliability, and state energy policy, remain the sole purview of local authorities.
- Increased scope of functionality and growth in number of market participants increases the complexity of the wholesale market and calls for development of new expertise from state policymakers and staff.
- If a Southeast RTO (rather than joining PJM) is pursued, implementation complexity and timeframes will be increased; implementation efforts will stall if utilities and policymakers in other Southeastern states are not (or do not remain) fully aligned on market design and a sustained commitment to implementation.

RTO IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Joining PJM: South Carolina could join an existing neighboring RTO (that is, PJM), ideally together with the portions of Duke Energy in North Carolina (as assessed in the present study) or possibly on its own (as described further below). By joining PJM, South Carolina stakeholders would be inheriting the existing market structure and governance that has already been established in PJM. This provides the benefit of experience and speed, but limits the chance to revisit the founding articles of governance and the market's overall design. Of the three major wholesale market reforms, this approach is the fastest and most decisive, and offers the highest net benefits.

PJM is an established RTO and experienced with the orderly integration of new utilities, most recently Eastern Kentucky Power Cooperative in 2013 and, before that, Duke Energy Ohio and Duke Energy Kentucky in 2012. Many vertically integrated utilities are operating within PJM under a state oversight model similar to South Carolina, including those in Virginia, Kentucky, Indiana, and West Virginia. Should South Carolina wish to pursue competitive generation or retail supply, PJM provides a proven platform for enabling either or both of those.

PJM integrations since 2002 have been accomplished in under two years. As shown in Table 6, case studies from 2012 and 2013 show an implementation time of 18 months to join PJM (including regulatory approvals and simultaneous technical integration) and an integration cost on the order of $1 million.[74] An integration effort of comparable or greater cost is also required internal to each integrating utility. As one indicator of a potential low-end estimate for utility-side RTO integration costs, the lowest documented utility-side integration cost we identified is $1 million cited in the EKPC integration (escalated and annualized this amounts to $0.14 million). An indicator of the high-end is illustrated by Dominion's 2004 integration to PJM—escalated to $2022 this equates to $37 million in one-time costs, or approximately $4 million per year if annualized over 15 years.[75] We therefore use a range of $0 - $4 million to represent approximate utility-side RTO integration costs.

Integration tasks consist of communicating technical details of each transmission and generation facility to PJM so that detailed models of such facilities can be expanding to include the broader footprint. New business process are implemented at the utility for ongoing communication of operational details, and in some cases new hardware is added for monitoring transmission lines. Demand response programs may need to be altered in order to participate in the PJM capacity market and energy markets.

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[74] Federal Energy Regulatory Commission, 139 FERC ¶ 61,068, Docket No. ER12-91-000, ER-12-91-002, ER12-92-002, Order 462, Page 9, issued April 24, 2012; PJM and EKPC, "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative," January 9, 2012. Included in "East Kentucky Power Cooperative, Inc. submits Request for Waiver to Participate in PJM Reliability Pricing Model Auctions under ER13-414," filed November 15, 2012.

[75] Federal Energy Regulatory Commission, Docket No. ER04-829-000, Page 17, May 11, 2004; "Joint Application to Establish PJM South"; Kentucky Public Service Commission, Case No. 2012-00169, Exhibit 4, Page 11, May 3, 2012; "The Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, L.L.C."; U.S. Bureau of Labor Statistics, CPI for All Urban Consumers, seasonally adjusted.

TABLE 6. IMPLEMENTATION CASE STUDIES FOR INTEGRATION WITH PJM

	Duke Energy Ohio/Kentucky Integration to PJM	Eastern Kentucky Power Cooperative Integration to PJM
Integration cost to the utility	Estimated at $1 million[76] PJM cost, together with a comparable cost to the utility	Estimated at $750,000[77] PJM cost, together with a comparable cost to the utility
State and FERC approval timeline	About two years: • State: initial KY PSC approval request filed May 20, 2010; final approval on Dec. 22, 2010[78] • FERC: Duke indication of intent to switch from MISO to PJM on June 25, 2010; formal request to join PJM filed Oct. 14, 2011.[79] FERC approval on April 24, 2012 (retroactively effective Jan. 1, 2012).[80]	About one year: • State: initial request on May 3, 2012, final approval on Dec. 20, 2012[81] • FERC: initial request on March 28, 2013, FERC approval on May 22, 2013[82]
Technical integration timeline	One and a half years: • Duke signed integration agreement with PJM on June 25, 2010, followed by high-level planning[83] • Integration went live on Jan. 1, 2012	One and a half years: • EKPC signed integration agreement with PJM on Jan. 9, 2012, followed by high-level planning[84] • Integration went live on June 1, 2013

State-level regulatory approvals are sometimes required when a utility joins an RTO. While new state laws or regulations are not required for a utility to join an RTO, some states do pass laws to compel utilities to join an RTO, together with regulations that describe the minimum requirements for an organization to be considered an RTO from the state's perspective. South Carolina could look to three examples of such law and regulation, each of which comes from states with vertically integrated utility structure that is broadly similar to South Carolina:

- Virginia state code Title 56, Chapter 23, section 579, "Regional transmission entities," which describes the criteria for meeting the state obligation to join an RTO. The corresponding

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76 Federal Energy Regulatory Commission, 139 FERC ¶ 61,068, Docket No. ER12-91-000, ER-12-91-002, ER12-92-002, Order 462, Page 9, issued April 24, 2012.

77 PJM and EKPC, "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative," January 9, 2012. Included in "East Kentucky Power Cooperative, Inc. submits Request for Waiver to Participate in PJM Reliability Pricing Model Auctions under ER13-414," filed November 15, 2012.

78 Kentucky Public Service Commission, Case No. 2010-00203 Received, May 20, 2010. Kentucky Public Service Commission, Case No. 2010-00203 Order, December 22, 2010.

79 "Duke Energy Ohio, Inc et al submits the first step of their proposed move from the Midwest ISO to PJM Interconnection under ER10-1562," June 25, 2010; Federal Energy Regulatory Commission, 362 FERC ¶ 61,068, Docket No. ER12-91-000, October 14, 2011

81 Kentucky Public Service Commission, Case No. 2012-00169, May 3, 2012; Kentucky Public Service Commission, Case No. 2012-00169, December 20, 2012.

82 "East Kentucky Power Cooperative, Inc. submits tariff filing per 35.13(a)(2)(iii: Revisions to the PJM OATT, OA & RAA re EKPC Integration," March 28, 2013, Docket ER13-1177-000; "Letter order accepting East Kentucky Power

regulations in Virginia state Administrative Code Title 20, Chapter 320, "Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities" further enumerates the requirements for an RTO in Virginia.

- Colorado Senate Bill 21-072 and Nevada Senate Bill 448 both establish relevant authorities, timelines, and evaluation criteria for regional market integration.[85]

RTOs' ongoing operating costs are funded by consumers. These costs are at least partly offset by cost savings associated with the transfer of certain operational and planning functionality from the utility to the RTO. According to FERC data from 2018, RTO charges have ranged from $0.35/MWh to $1.60/MWh.[86] In 2021, the PJM rate stood at $0.40/MWh.[87] Conservatively neglecting offsetting administrative savings within South Carolina utilities, a rate of $0.40/MWh in the context of South Carolina in 2030 amounts to $36 million per year.[88] In our assessment of net benefits of the RTO market reforms, we use this value to estimate PJM's approximate annual administrative cost to South Carolina customers.[89] This is a conservative estimate in the PJM context, since the presence of South Carolina would bring economies of scale to PJM that would tend to put downward pressure on the administrative cost per MWh.

PJM identifies higher-voltage regional transmission upgrades that are necessary for reliability. When member transmission owning utilities build such upgrades (with approval from the state regulator), half the cost is allocated across the entire RTO. If South Carolina utilities joined PJM

Cooperative, Inc's 3/28/13 submittal of a joint filing in connection with EKPC's integration into PJM," Docket ER13-1177-000, May 22, 2013.

82 "East Kentucky Power Cooperative, Inc. submits tariff filing per 35.13(a)(2)(iii: Revisions to the PJM OATT, OA & RAA re EKPC Integration," March 28, 2013, Docket ER13-1177-000; "Letter order accepting East Kentucky Power Cooperative, Inc's 3/28/13 submittal of a joint filing in connection with EKPC's integration into PJM," Docket ER13-1177-000, May 22, 2013.

83 Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., Initial Filing before the Federal Energy Regulatory Commission (FERC), June 25, 2010.

84 "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative." Included in "Duke Energy Ohio, Inc et al submits the first step of their proposed move from the Midwest ISO to PJM Interconnection under ER10-1562," June 25, 2010.

85 General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, (2021), signed June 10, 2021.

86 Federal Energy Regulatory Commission, "Common Metrics Staff Report, 2014 to 2018," Docket No. AD19-16-000, Page 44, July 2021.

87 PJM, "Administrative Rate Proposal," slide 13, September 29, 2021.

88 In our 2030 simulation scenario, South Carolina has a total of 90,370 GWh of annual load.

89 The annualized value of the approximately $1 million one-time cost that PJM charges to integrate a new utility does not significantly increase the $36 million result.

(as opposed to partnering with PJM in a non-RTO pooling arrangement, as described in the discussion of "Implementation Considerations for South Carolina" in Section II.D), customers in other PJM states would ultimately contribute to funding these upgrades, while customers in South Carolina would enjoy the reliability and operational benefits. On the other hand, the South Carolina utilities would be allocated such costs from upgrades in other states. A PJM tool for estimating such costs based on existing and planned regional transmission upgrades indicates that South Carolina's share could be approximately $28 million annually in 2030.[90] This would initially result in a net increase in transmission costs to South Carolina, prior to construction of new regional transmission facilities. If such costs were included in the net benefit calculation, the result would show a net benefit of joining PJM that is lower—using the $28 million estimate, the net benefit would be between $253 – $334 million annually. However, as new regional transmission facilities were built, net benefits could rise or fall according to the specific regional transmission facilities built, their degree of improvement of operational efficiency in South Carolina, their cost, and the extent to which that cost were allocated out of state.

If it were not practical to coordinate with the North Carolina utilities to join PJM together in a common strategy and timeline, some or all of the South Carolina utilities could join PJM individually and at different times. Depending on the sequence of other utilities' integration plans, the state may initially (or permanently) join as a non-contiguous part of PJM, with a contract-path transmission link but limited PJM integration to intervening transmission capability.[91] Transfers between South Carolina and PJM through North Carolina (or potentially other regions) would be accomplished using today's Tariff-based wheeling transmission scheduling protocols. The RTO would then incorporate those transmission schedules into its dispatch and other processes. Establishing firm transmission from South Carolina to PJM would likely be necessary, especially for robust pooling of resource adequacy and other planning. The more limited RTO participation of South Carolina utilities combined with the limited scope of a contract-path

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90 To capture this cost, we used PJM's Transmission Cost Information Center (TCIC) tool to estimate the cost that would be allocated in 2030 to South Carolina plus Duke's North Carolina utilities based on PJM coincident peak-load ratio share. This was then allocated to South Carolina based on its estimated share of coincident peak values. Coincident peak load values were calculated using projected hourly load data for Balancing Authorities in the Carolinas and PJM, as well as the South Carolina share of the Carolinas utilities. See TCIC tool at PJM, "Project Status and Cost Allocation", accessed April 7, 2023.

91 It is theoretically (but likely not practically possible) that Duke's South Carolina territories could join PJM without the North Carolina portion, as this would require that each Duke utility to reconfigure their internally-pooled operations that currently span the two states, which would introduce operational inefficiencies and also require extensive new metering equipment.

transmission link would reduce the achieved benefits, but may still have the effect of spurring more neighboring utilities and state regulators to examine the potential RTO benefits.

This contract-path transmission approach to RTO participation and other pooling arrangements has been used before: when Commonwealth Edison joined PJM in 2004, and in the initial years of CAISO's WEIM, when PacifiCorp West and Puget Sound Energy were non-contiguous.[92] Over time the regional scope of each regional market has expanded, which has integrated the initial member more robustly as more utilities have joined the markets.

Starting a Southeast RTO. Formation of a new multi-state Southeast RTO would allow South Carolina's state regulators, utilities, and other stakeholders to join with other Southeastern states in establishing the independent entity, developing its governance structure, and designing its market rules to fit the needs of the broader region. On the other hand, this would be no small task—it would require consensus across many states that would likely take years to obtain. All of today's RTOs grew out of predecessor organizations that had been coordinating utility operations for decades, thus facilitating consensus-building for the launch of an RTO.[93] In order to tackle the start-up effort in a more manageable way, the utilities might initially focus on a simpler EIM model, and then transition to a more full-featured RTO over time, as was the case for most of the established RTOS and has been playing out in the Western EIM over the last 12 years. Many of today's RTOs launched with much-reduced functionality that focused on real-time trades (sometimes without even a real-time energy market at all—a "day one RTO").

A Southeast RTO with the footprint of SEEM (as studied in the present report) would cover 10 states (the Carolinas, Tennessee, Kentucky, Georgia, Alabama, Florida, Mississippi, Missouri, and Oklahoma). In addition to achieving consent from each utility, each state would have to: (a) permit their utilities joining an RTO; and (b) accept the governance structure of the RTO. Such an effort could reasonably be initiated with a commitment from several states as well as the region's large utilities (e.g., Duke, TVA, and Southern Company).

[92] Yan Lin, et al., Impact assessment of expanding PJM market area by incorporating incremental loss model, IEEE Power Engineering Society General Meeting, 2005, Pages 326–331 Vol. 1, June 16, 2005.

[93] ISO New England had been NEPOOL, founded in 1971; NYISO had been the New York Power Pool, 1969; PJM was founded in 1927; MISO grew out of discussions among the members of the Mid-American Interpool Network (MAIN, founded 1964 and merged with MISO in 2000) and the East Central Area Reliability Council (ECAR, 1967), and quickly took over the operations of the Midcontinent Area Power Pool (MAPP, formed in 1965); ERCOT was founded in 1970; SPP was founded in 1941; and CAISO grew out of the California Power Pool, 1961.

The process of creating an RTO has historically taken several years of stakeholder consensus building before administrative operations can start, followed by a further multiyear effort for establishing energy market operations. For example, the utilities that would go on to form MISO started discussions in early 1996, made their initial FERC filing in 1998, and started operations as an RTO in 2001.[94] Their initial role was limited to administering the common tariff and regional transmission service, and it was not until 2005 that they launched their energy market. SPP's initial RTO filing was made in 2000, followed by a second in 2003.[95] They launched in 2004, began a real-time EIM-style energy market in 2007, and implemented full RTO market functionality in 2014. Notwithstanding this record, it is possible that stakeholders in the Southeast could move more quickly towards consensus than the MISO and SPP processes suggest. Moreover, implementation time could proceed more quickly now that RTOs have extensive experience building and running the requisite infrastructure and processes, which the Southeast RTO could leverage by subcontracting with an existing RTO (such as SPP, MISO, or PJM) to host the operational infrastructure (thereby also lowering cost). This "subcontracting RTO operations" approach was contemplated by the Mountain West utilities in Colorado and Wyoming, when they were considering creating the Mountain West RTO (as discussed earlier).

An indication of the potential range of administrative costs allocated to South Carolina from a new Southeast RTO can be derived from costs from other present-day RTOs. As the lowest-cost RTO, PJM's administrative cost of $0.40/MWh can indicate an approximate low end of the range, while SPP's cost of approximately $0.58/MWh can indicate a high end (CAISO and ISO New England rates are higher still, but SPP labor costs better reflect conditions in the Southeast).[96] Using South Carolina's modeled 2030 load of 90,320 GWh, these scenarios indicate an approximate range of $36 – $52 million annually.

RTO administrative charges often include recovery of capital costs for prior investments. If a new Southeast RTO partners with an existing RTO to leverage existing infrastructure, then the current RTO administrative rates could be indicative of the low end of costs for the Southeast. Otherwise, investments needed to start a new RTO could contribute to additional administrative costs. An indicator of the high end of such cost can be drawn from the implementation of a nodal market

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94 Midwest ISO, "Midwest ISO Filing," Docket No. ER98-1438-000, January 15, 1998; "MISO History," accessed February 13, 2023.

95 SPP, "Southwest Power Pool Inc submits its RTO proposal," October 13, 2000, Docket No. RT01-34-000; FERC, "SPP," accessed February 13, 2023.

96 Federal Energy Regulatory Commission, "Common Metrics Staff Report, 2014 to 2018", Docket No. AD19-16-000, Page 44, July 2021; PJM, "Administrative Rate Proposal," slide 13, September 29, 2021.

in ERCOT. ERCOT's project was associated with unexpected cost overruns and delays, ultimately costing $509 million.[97] Annualized over 15 years at a rate of 8%, this amounts to an added annual cost of $77 million allocated across the entire Southeast RTO footprint, with South Carolina's share calculated at $10 million per year.[98] To the high end of the administrative cost range, we also add the $4 million cost associated with utility-side investments described in the PJM analysis above.

F. Enhanced Regional Transmission Planning

DESCRIPTION AND RELEVANT CASE STUDIES

Regional transmission planning refers to development of transmission that spans or otherwise affects multiple utilities. Regional transmission investments serve to integrate operations across multiple utilities to multiply the value of pooled operations and facilitate pooled resource adequacy. Regional transmission planning can provide cost savings from congestion relief, more effectively and efficiently serve growing load, improve reliability and resilience, and provide access to low-cost renewables.

Today, almost all investments in regional transmission are a result of RTO planning processes, one of the core functions of an RTO. The RTO's pooling of operations is a natural complement to regional transmission planning, and vice versa. If utilities mainly operate within their own boundaries, and trade across their borders is moderate and limited by frictions, it is harder to justify transmission upgrades between utilities; likewise, if there is minimal transmission connecting utilities, there is less ability to trade.

In parts of the country that (like South Carolina) are outside RTO areas, transmission upgrades are mainly planned by each utility and upgrades prompted by regional transmission planning processes are less common. Such regional transmission planning is facilitated by transmission planning entities and agreements, some of which operate according to FERC regulation under Order 890 and Order 1000. These orders are intended to ensure that interstate transmission services are provided at just and reasonable rates and on a basis that is not unduly discriminatory or preferential, consistent with FERC's duty under the Federal Power Act. Dominion Energy South Carolina and Santee Cooper participate in the FERC-regulated South Carolina Regional

[97] Lester, Todd K., Clay Ryals, Dan Stathos, and Jared Jordan, "Evaluation of ERCOT's Texas Nodal Market Implementation Project (TNMIP)", Navigant Consulting, August 30, 2012.

[98] South Carolina's share of the Southeast's coincident peak is 13%. See Appendix A, page A-2.

Transmission Planning group, while Duke participates in Southeastern Regional Transmission Planning).[99] These groups are helpful for coordinating planning studies among member utilities and confirming their systems are expected to operate reliably, even as they evolve. In some cases, the coordinated studies identify upgrades that utilities must perform on their own systems, or even inter-utility upgrades. However, most regional planning cycles in non-RTO areas across the United States do not result in any transmission upgrades between two utilities, let alone regional transmission upgrades that are selected for cost allocation through the Order 890 and Order 1000 processes.[100]

Other transmission coordination groups exist outside the construct of FERC Orders 890 and 1000. For example, the Carolinas Transmission Coordination Agreement (CTCA), the SERC Long Term Study Group (LTSG), the Eastern Interconnection Planning Collaborative (EIPC), and the Eastern Interconnection Reliability Assessment Group (ERAG). These are effective at identifying reliability violations and similar concerns, including at the regional and sub-regional level, but they have not resulted in major regional upgrades spanning multiple utilities of the type that yield large cost savings or facilitate significant shifts in the resource mix.

Improved regional transmission planning offers the opportunity to significantly reduce costs for consumers through more efficient and reliable operation and access to resources. Brattle has recommended that policymakers pursue several enhancements to the regional transmission planning process, including as applied both inside and outside RTOs in the United States.[101] These recommendations encourage multi-value assessment, scenario-based assessment, and improved cost allocation. The multi-value approach ensures that processes explicitly account for all values of transmission, including reliability, reduced congestion, and achievement of policy goals. We

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99 Southeastern Regional Transmission Planning (SRTP), "Southeastern Regional Transmission Planning," accessed February 13, 2023.

100 For example, the 75-page WestConnect regional transmission plan report concludes by stating: "*Based on the findings from the 2020–21 planning cycle analysis performed for reliability, economic, and public policy transmission needs as described in this report, no regional transmission needs were identified in the 2020–21 assessment.*" WestConnect, "WestConnect 2020–21 Regional Transmission Planning Cycle," December 15, 2021. Further, the Sustainable FERC Project, Natural Resources Defense Council, the Sierra Club, et al., state that "*regional transmission planning in non-RTO regions is essentially nonexistent*" and "*only two regional transmission projects have been identified in the SERTP planning process since 2014*." Public Interest Organizations, "Comments Of Public Interest Organizations in RE: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," October 12, 2021, Docket No. RM21-17-000.

101 J. Pfeifenberger et al., A Roadmap to Improved Interregional Transmission Planning, The Brattle Group, November 30, 2021.

provide the following suggestions for state policymakers that can influence regional transmission planning processes:

- Encourage use of multi-value benefit analysis to assess the extent to which certain regional transmission investments can reduce overall customer costs (e.g., by offering a more cost-effective transmission solution than individual utility-planned projects or by reducing generation-related costs);
- Consider whether multi-state regional planning authorities are necessary for identifying policy-related needs for increased transfer capability between states and regions in the absence of a federal planning process;
- Engage regional planning authorities to modify the approach to analyzing regional transmission needs and transmission-related benefits that reduce overall customer costs;
- Develop scenarios for regions to consider in regional planning efforts, including with future resource mixes that achieve existing state policy mandates and plausible new future policy goals; and
- Propose and support innovative, flexible, and portfolio-based cost allocation for interregional public policy projects.

The above recommendations would need to be pursued in coordination with other regional stakeholders and federal policymakers, since the regional planning process is regulated by FERC. The most significant action that South Carolina policymakers can take to achieve cost savings from improved regional transmission planning is to require South Carolina utilities to more actively coordinate transmission planning or to join an RTO. RTOs already have in place robust regional transmission planning processes that yield major inter-utility investments to improve congestion, reliability, and achieve state policy goals. RTOs thus provide a ready template that would represent a step forward for South Carolina, whether joining PJM or forming a new Southeast RTO. Table 7 provides examples of multi-value regional transmission planning from the RTO processes.

TABLE 7. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS TO ASSESS THE EXTENT TO WHICH TRANSMISSION PROJECTS CAN REDUCE TOTAL CUSTOMER COSTS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified			
Production cost savings: value of reduced emissions reduced AS costs	Production cost savings	Production cost savings and reduced energy prices from both a societal and customer perspective	Production cost savings
Avoided transmission project costs	Reduced operating reserves	Mitigation of market power	Capacity resource cost savings
Reduced transmission losses capacity benefit energy cost benefit	Reduced planning reserves	Insurance value for high impact low-probability events	Reduced refurbishment costs for aging transmission
Lower transmission outage costs	Reduced transmission losses	Capacity benefits due to reduced generation investment costs	Reduced costs of achieving renewable & climate goals
Value of reliability projects	Reduced renewable generation	Operational benefits (RM)	
Value of meeting policy goals	Reduced future transmission	Reduced transmission losses*	
Increased wheeling revenues	Investment Costs	Emissions benefit	
Not Quantified			
Reduced cost of extreme events	Enhanced generation policy flexibility	Facilitation of the retirement of aging power plants	Protection against extreme market conditions
Reduced reserve margin	Increased system robustness	Encouraging fuel diversity	Increased competition and liquidity
Reduced loss of load probability	Decreased nat. gas price risk	Improved reserve sharing	Storm hardening and resilience
Increased competition/liquidity	Decreased CO2 emissions	Increased voltage support	Expandability benefits
Increased congestion hedging	Decreased wind volatility		
Mitigation of uncertainty	Increased local investment and job creation		
Reduced plant cycling costs			
Societal economic benefits			

Source/Notes: J. Pfeifenberger et al., A Roadmap to Improved Interregional Transmission Planning, The Brattle Group, November 30, 2021.

POTENTIAL ADVANTAGES

Whether improved regional transmission planning is pursued through an RTO or other means, the considerations are largely the same. The main benefit is an improved ability to reduce costs, including through facilitating the exchange power with neighboring utilities, which yields these advantages:

- Identification of more cost-effective regional transmission solutions.
- Improved transmission system reliability.

- Improved resilience in the face of low-probability events.
- Cost savings from reduced transmission congestion and improved trading with neighbors.
- Ability to interconnect lower-cost renewables inside and outside each the utility's footprint.
- A potential reduction in installed reserve margin requirement needed to meet the same reliability target by being more strongly interconnected to a larger geographic market with higher load and resource diversity.

POTENTIAL DISADVANTAGES

- Disagreements over cost allocation for regional transmission projects (regional sharing of costs may create the impression that some regions are winners or losers).
- State regulators will tend to have more jurisdictional influence over utility-specific transmission projects than regionally planned transmission.

G. Benefit-Cost Assessment of Potential Wholesale Market Reforms

We simulated a 2030 scenario of the South Carolina and regional wholesale power markets to quantify the estimated future benefit to South Carolina consumers from each wholesale market reform in two broad domains: (1) **operational cost savings** (i.e., savings from improved generation dispatch and trade, applicable to the JDA, EIM, and RTO scenarios), and (2) **investment savings** that arise from reduced capacity requirements due to load diversity benefits realized from pooling over a larger footprint. Additionally we benchmarked our operational model to historical data and benchmarked our overall results to a literature review of the benefits of wholesale market reforms in other jurisdictions, summarized below.

We note that our estimates of net benefits may be conservatively low due to the following modeling approaches and assumptions:

- The model does not account for day-ahead forecast error of renewable generation and load. The model applies the same hourly load and renewable generation in the day-ahead unit commitment and dispatch optimization, as in the real-time optimization. Therefore, our simulations do not capture the benefit regional wholesale markets provide by optimizing real-time dispatch to manage imbalances.
- The modeling results reflect hourly granularity with full foresight of real-time market conditions (i.e. without uncertainty). This will understate the intra-hour, real-time benefits of

a JDA, EIM, and RTO and result in understated total net benefits, more so in the case of an RTO, relative to the Status Quo.

- The simulation does not include transmission outages, which understates the efficiency gains achieved in a regional market. The optimization performed in a wholesale market can lower the cost of re-dispatching the system during transmission outages, by drawing on resources from across the footprint.
- The model utilizes natural gas fuel price forecasts provided by the Advisory Board utility members. Forecasts apply average price volatility and average geographic differences in prices, which does not capture periods of extreme volatility and large regional fluctuations in gas prices, such as those experienced during severe winter weather. Modeling natural gas price volatility in line with these events would increase the operational benefits of all regional market options studied by creating larger gains from trading power across the market footprint.
- The simulated SEEM transactions in our 2030 Status Quo Case are more than ten times higher than the observed historical transactions in SEEM since its launch (comparing the current SEEM footprint, excluding Florida utilities, with the same footprint in the model). Therefore, our representation of the Status Quo, including SEEM, in 2030 is significantly more efficient than SEEM has been since its launch and assumes that SEEM would develop in the future. However, if the SEEM transaction volumes remain closer to historical volumes, the incremental benefits from the other market reform options studied (the JDA, EIM, and two RTO options) would be greater than estimated (see Appendix C).
- Our analysis assumes that only the existing transmission assets, or planned assets expected to be online by 2030, are available. Therefore, the net benefits reported are what is feasible given that transmission infrastructure. If South Carolina utilities were to build new transmission infrastructure with the approval of the South Carolina PSC, this would increase the trading capabilities between the South Carolina BAAs or with neighboring BAAs and the benefits of joining a regional market would increase.
- Our analyses of administrative and implementation costs are based on experience elsewhere with few examples of publically disclosed costs in some cases. If actual administrative and implementation costs are lower than these past studies, net benefits would be greater.

BENEFITS REALIZED FROM WHOLESALE MARKET REFORMS IN OTHER JURISDICTIONS

Since the launch of organized regional wholesale power markets in the 1990s, many studies have been performed to quantify their benefits. Each focused on a different geographic area, or covered a different set of the potential benefits of an RTO, but they generally all included operational cost savings usually referred to as "production cost savings." These are the savings in fuel and maintenance costs when the scheduling and dispatch of a fleet of generators is optimized across a very wide area, rather than being optimized separately within each utility. Forward-looking production cost estimates often are used by utilities that are considering joining an RTO or EIM and seek to understand the net benefits to their customers. We have performed several studies like this recently, as summarized in Table 8.

TABLE 8. STUDIES OF POTENTIAL RTO AND EIM EXPANSIONS

Name	Study Region	Year	Estimated Cost Savings
Western Energy Imbalance Service and SPP Western RTO[102]	SPP WEIS vs. RTO expansion in the Western United States	2020	Production cost savings of around 4% for new members joining the WEIS or SPP RTO.
WEIM vs. WEIS benefits study for Black Hills Energy, CSU, PRPA and PSCO[103]	WEIM vs. WEIS expansion in Colorado	2020	Production cost savings range from 0.3% to 3.6% for new members joining the WEIM or WEIS.
Mountain West Transmission Group[104]	RTO market formation in Colorado and Wyoming	2016	Production cost savings of 5%–9%. Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability
California SB350[105]	RTO market formation in western U.S.	2016	$1–$1.5 billion per year in production and investment cost savings for California ratepayers from participation in a Western-wide RTO market
Basin/WAPA/ Heartlands[106]	Benefit from Joining SPP or MISO	2013	Production cost savings of 3%–4% Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source/Notes: See footnotes.

Retrospective studies to evaluate the cost savings offered by EIMs and RTOs with the benefit of hindsight also have been performed. The RTOs periodically conduct such studies, comparing actual costs (for power production, generation investment, and transmission investment) with estimated costs that would have been in the absence of the RTO. Such backwards-looking studies often measure more types of benefits, not only those from (operational) production cost savings. These are summarized in Table 9.

[102] J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020.

[103] J. Chang, et al., Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020.

[104] J. Chang, et al., Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.

[105] The Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), July 8, 2016.

[106] M. Celebi, et al., Integrated System Nodal Study: Costs and Revenues of ISO Membership, The Brattle Group, March 8, 2013.

TABLE 9. STUDIES OF COST SAVINGS FROM EXISTING WHOLESALE MARKETS

Region	Study	Year	Estimated Cost Savings
MISO[107]	2021 Value Proposition Study	2021	• $3.0–$3.8 billion annually
Western EIM[108]	Q4 Value Study	2022	• $739 million in savings in 2021 • $1.4 billion in savings in 2022 • $3.4 billion cumulative cost savings since 2014
PJM[109]	PJM Value Proposition	2019	• $3.2–$4.0 billion annually
SPP[110]	2021 Member Value Study	2021	• $2.1 billion annually
SPP, Western Energy Imbalance Service (WEIS)[111]	2022 Member Value Study	2022	• $31.7 million in net benefits in 2022 • $61.2 million in cumulative net benefits since 2021
PJM (Dominion Virginia Service Territory)[112]	2015 PUC filing on Benefits of PJM Membership	2015	• $109 million of production cost savings in 2014 • $75 million of production cost savings in 2013 • Cumulative 2005–2015 benefits filed with NC PUC, but not made public • Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source/Notes: See footnotes.

The extent of net benefits can vary for different utilities and geographies. Important factors include the efficiency and resource mix of each utility's generation fleet, the level of renewable resource deployment in the area, and the hourly and seasonal trends for customer demand in each utility (for example, a mix of summer and winter peaking utilities). For example, if electricity demand is low at one utility at the same time that it is high at another, significant benefits can accrue to both utilities through regional sharing of generation output to meet combined electricity consumption. The cost savings for RTOs vary by region because these factors are

[107] MISO, "2021 MISO Value Proposition," March 9, 2022.

[108] California ISO, "Western EIM Benefits Report: Fourth Quarter 2022", January 31, 2023.

[109] PJM, PJM Value Proposition accessed February 13, 2023.

[110] SPP, 2021 Member Value Study, April 6, 2022.

[111] SPP, Benefit of the Market Western Energy Imbalance Service (WEIS), March 27, 2023.

[112] Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2015-00022, February 27, 2015; and Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2014-00033, May 2, 2014.

different from place to place, as seen in the differences in estimated cost savings shown above in Table 9.

QUANTITATIVE MODELING OF BENEFITS OF WHOLESALE MARKET REFORMS IN SOUTH CAROLINA

The dispatch of generators incurs major fuel and maintenance costs, and optimization of generator scheduling and dispatch across wide areas can produce significant operational cost savings, together with better utilization of existing transmission infrastructure for trades between utilities and other market participants. We studied four wholesale market reforms that achieve such coordination—a Carolina JDA, a Southeast EIM and RTO that cover the current SEEM footprint, and an RTO case in which the Carolina utilities join PJM—each described in detail below. Meanwhile, we calculate the savings in capital cost from regional coordination of system planning in generation investment. Two of the wholesale market reforms also achieve these savings, as detailed below.

We performed quantitative assessments of **operational cost savings** detailed using a simulation of South Carolina and regional electric grid operations for 2030, spanning from New Jersey to Illinois, Missouri, and Tennessee, and from Alabama to Florida, as described in detail in Appendix B and Appendix C. We additionally calculated estimated **investment savings** by analyzing the diversity of hourly loads between the status quo and the two RTO scenarios described below and in detail in Appendix A.

As discussed further below, the model omits some details that would tend to increase the value of regional coordination, and so these results are conservative. Moreover, while the model includes projected deployments of wind, solar, and storage through 2030, these results would tend to be higher as such shares of wind and solar continue to grow beyond the study period, and so benefits would be expected to grow in time.

DESCRIPTION OF MODELED SCENARIOS

The Carolinas **Joint Dispatch Agreement (JDA)** scenario combines the real-time operations of Dominion Energy South Carolina, Santee Cooper, and the Duke Energy utilities in both North and South Carolina (including Duke Energy Carolinas and Duke Progress Energy). The study assumes each utility retains the separate Balancing Authority roles as assigned in the Status Quo. The South Carolina municipal utilities and Central Electric Cooperative are accounted for within the four South Carolina Balancing Authorities. Following typical JDA operations, each utility schedules their own load in the day-ahead cycle (including high-friction bilateral trades where the advantage exceeds the hurdle rate), while real-time operations feature almost seamless cross-utility optimization (except a small hurdle rate representing the simplistic representation of available transmission in the JDA construct).

The Southeast **Energy Imbalance Market (EIM)** scenario combines the real-time operations of the South Carolina utilities (including the North Carolina portions of Duke Energy) with those of other utilities in SEEM: the Tennessee Valley Authority (TVA), the Southern Company utilities, Louisville Gas and Electric/Kentucky Utilities (LGE/KU), Associated Electric Cooperative, Inc., Duke Energy Florida, Tampa Electric Company, PowerSouth, Seminole Electric Cooperative, and JEA. Like the JDA case, the existing configuration of Balancing Authority roles is not changed. Unlike the JDA case, the EIM has the ability to turn on fast-start gas generators in real-time, and fully utilizes inter-utility transmission via a more sophisticated optimization method.

The **Southeast RTO** scenario models both operational cost savings and investment savings. The model simulates pooled day-ahead scheduling of generators followed by pooled real-time dispatch, as well as consolidated Balancing Authority operations that pool reserves. Investment savings assume pooled resource adequacy across the entire footprint (without consideration of locational constraints). The Southeast RTO uses the same SEEM footprint as the EIM scenario.

The **PJM RTO** scenario uses the full RTO pooling functionality (the same as the Southeast RTO scenario above). Its footprint combines PJM, North Carolina, and South Carolina.

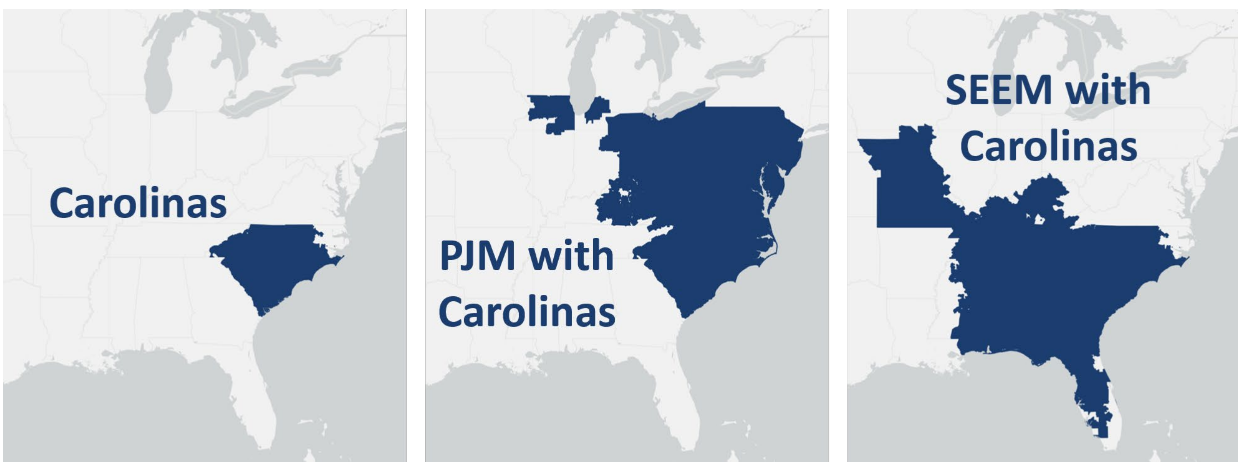
Table 10 below is a summary of the regions contained in each of the modeled scenarios while Figure 11 shows the maps of each modeled footprint.

TABLE 10. SUMMARY OF SCENARIO DEFINITIONS

Region	Totals for South Carolina	JDA	EIM	SERTO	PJMRTO
Dominion SC	X	X	X	X	X
Santee Cooper	X	X	X	X	X
Duke (SC portions)	X	X	X	X	X
Duke (NC portions)		X	X	X	X
Rest of Southeast *			X	X	
PJM					X

Source/Notes: *The EIM and SERTO footprints are identical to the SEEM footprint, including (in addition to Duke and the South Carolina utilities): TVA, Southern Company, LGE/KU, AECI, PowerSouth, Duke Florida, Seminole Electric Coop, JEA, and Tampa Electric.

FIGURE 11: MAPS OF THE MARKET REFORM STUDY AREAS



Source/Notes: S&P Global Market Intelligence, LLC, [Mapping Tool.](#) The JDA scenario covers the Carolinas area shown in the left most panel. The EIM and Southeast RTO scenarios cover the Southeast area shown in the right panel and the Carolinas with PJM scenario in the middle.

POTENTIAL OPERATIONAL COST SAVINGS FOR SOUTH CAROLINA

Our simulation analysis of the regional electricity markets in 2030 finds significant operational savings for South Carolina customers in each of the wholesale market reform scenarios, with the largest savings in the RTO cases, as shown in Table 11 below.

TABLE 11. 2030 OPERATIONAL COST SAVINGS OF DIFFERENT WHOLESALE MARKET REFORM OPTIONS. (IN 2022$ MILLIONS/YEAR, RELATIVE TO STATUS QUO)

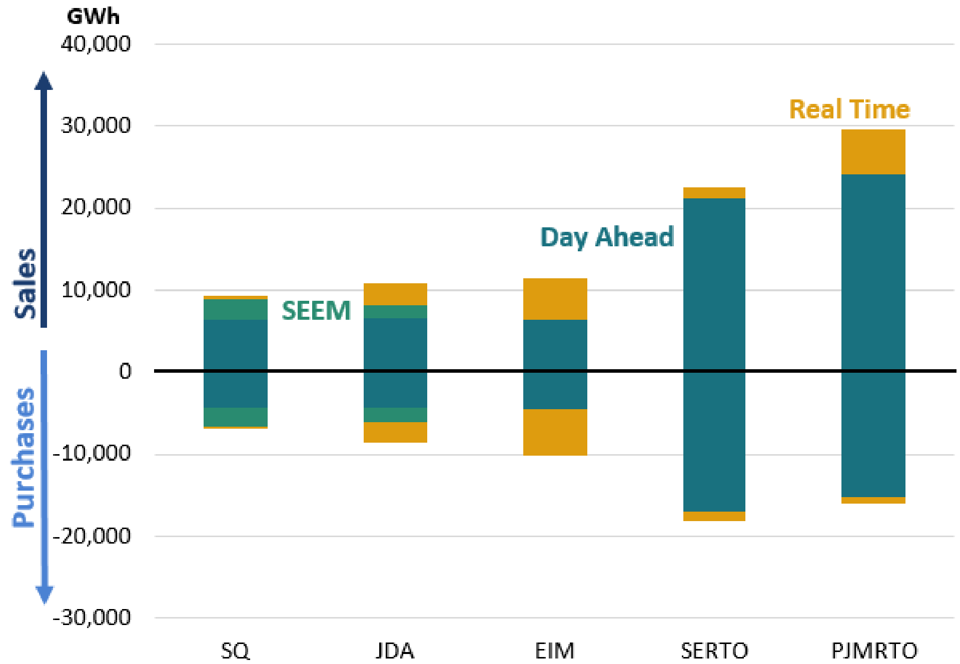
		Units		JDA		EIM		SERTO		PJM RTO
SC Balancing Authorities										
Duke	[1]	$ Mln	$	1	$	2	$	(9)	$	44
Dominion SC	[2]	$ Mln	$	7	$	6	$	64	$	74
Santee Cooper	[3]	$ Mln	$	3	$	16	$	42	$	64
South Carolina	**[4]**	**$ Mln**	**$**	**12**	**$**	**24**	**$**	**96**	**$**	**181**
Total Regional Market	[5]	$ Mln	$	15	$	99	$	228	$	322

Source/Notes:
Benefits include changes in adjusted production costs, wheeling revenues from OATT charges, and gains from trade, both within RTO footprints and external to them.
[1] to [3]: Only South Carolina share of benefits. Duke (21.34%), Dominion SC (100%), Santee Cooper (100%).
[4]: Sum of [1] to [3].
[5]: Total regional market is the sum of benefits for entire pooling region for each scenario

These operational savings reflect both the overall improvement in efficiency that these reforms provide, as well as the specific market position that South Carolina utilities hold in the new market, because not all areas of an expanded market footprint benefit equally.

Figure 12 provides some context for these operational cost savings by summarizing the bilateral and market-trades of the Carolina utilities for the status quo and the four analyzed market reform option. As the figure shows, the wholesale market reforms increase trading volumes, which (together with yielding more valuable trades) are one of the main drivers of cost reductions. The JDA and EIM both pool operations only in real time, and each increases real time trades. The RTO cases result in a more significant increase in trade volumes, largely by realizing savings available in the day-ahead energy markets.

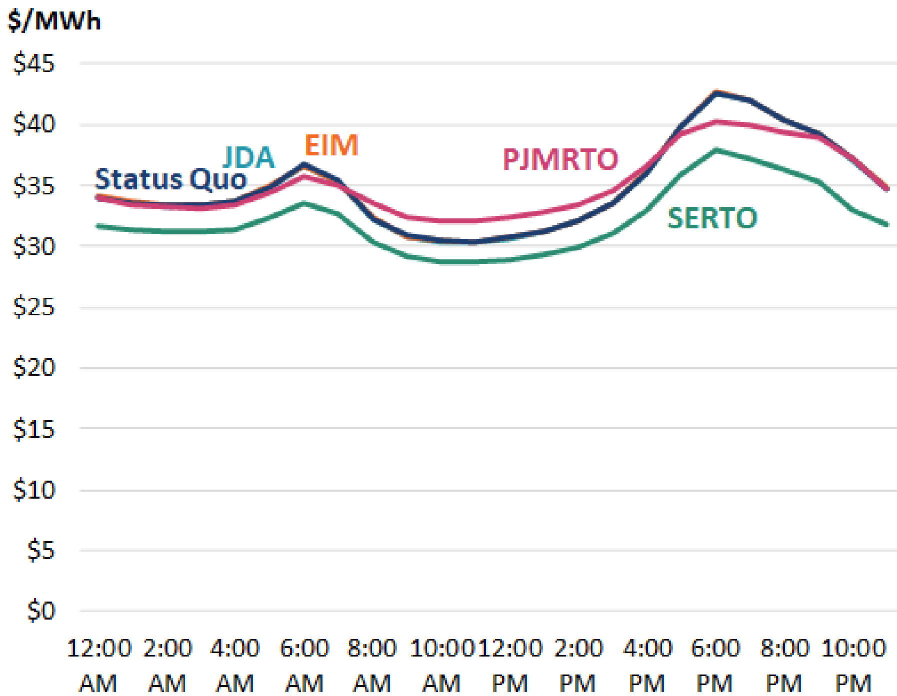
FIGURE 12: TRADING VOLUMES FOR CAROLINA UTILITIES BY WHOLESALE MARKET REFORM OPTION AND TRADING TIMEFRAME



Sources/Notes: Bars are stacked. Trading volumes show the total of Duke, Santee Cooper, and Dominion South Carolina transactions.

The average hourly prices shown in Figure 13 indicate that the average prices realized by Carolinas generators are effectively identical for the status quo, JDA, and EIM. This is because relatively little generation is settled in SEEM and real-time transactions. In contrast, the Southeast RTO market reform option uniformly lowers prices by around $3/MWh due to significant shares of solar and low-cost natural gas generation in the Southeast, which yields a regional supply curve that is shifted down and to the right relative to status quo. Conversely, the PJM option raises prices (and associated off-system sales revenues) during solar hours by around $1/MWh, lowers prices obtained by generators during the evening peak hours by around $2/MWh (as well as a slight reduction in morning hours). This is due to interactions with the solar share of the Carolina resource mix in PJM relative to the status quo. Because South Carolina is a net seller of electricity (particularly during high solar generation hours), the effect of a higher LMP for generation actually helps reduce costs to consumers in the PJM case.

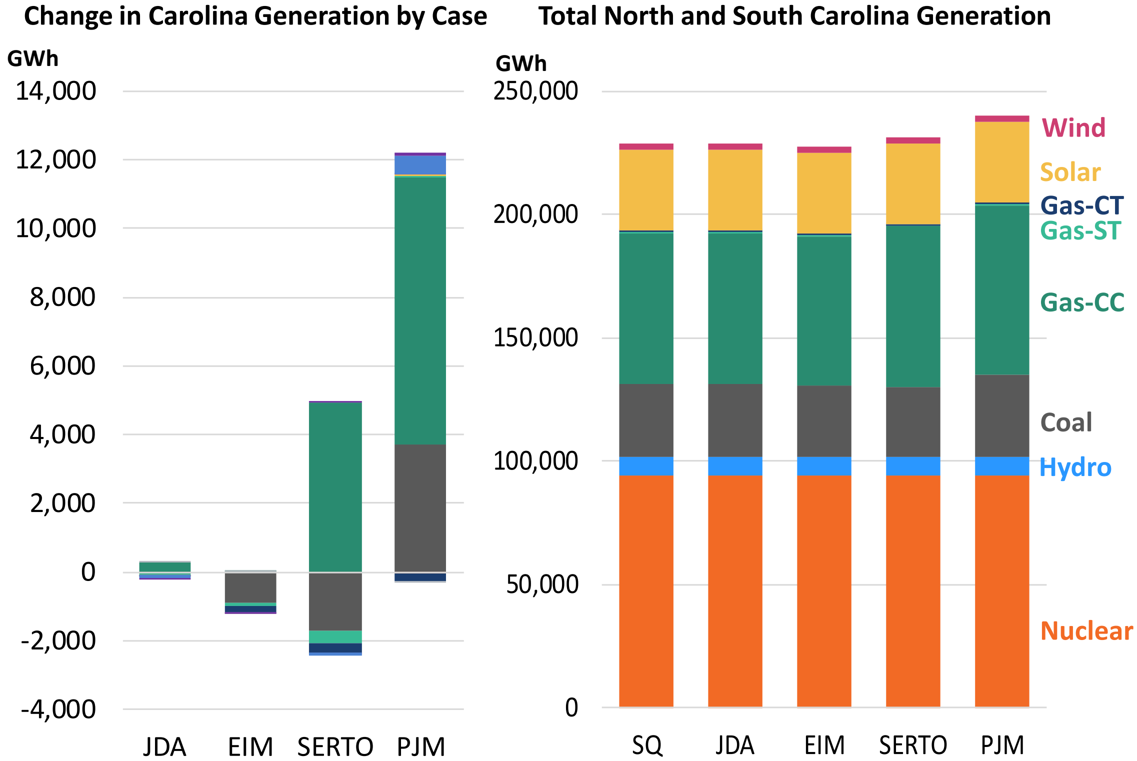
FIGURE 13: HOURLY DAY-AHEAD PRICES FOR GENERATOR OUTPUT AVERAGED ACROSS THE STUDY YEAR, BY MARKET REFORM OPTION



Notes: JDA and EIM average LMPs are nearly identical to status quo.

As shown in Figure 14, the RTO cases enable a significant increase in output from lower-cost natural gas combined-cycle generators of the three major utilities in the Carolinas. In the EIM and Southeast RTO cases, coal output in the Carolinas declines. In the PJM case, coal generation output increases.

FIGURE 14: TOTAL AND CHANGE IN CAROLINA GENERATION OUTPUT BY RESOURCE TYPE



Source/Notes: does not include generation output in the PJM portion of North Carolina.

The relative levels of the estimated operational cost savings for the different wholesale market reform options for South Carolina are supported by first principles: the JDA has a smaller footprint and lower functionality, and shows the lowest benefit; the EIM has a larger footprint (the same as the Southeast RTO case) and slightly improved functionality in how it optimizes real-time operations, which yields higher benefits; the estimated benefits for two RTO cases—with both day-ahead unit commitment and dispatch, real-time imbalance markets, and consolidated BA operations (which reduces and optimizes operating reserves)—are higher still. Appendix B presents these results and supporting study assumptions in more detail.

The finding that the RTO cases are most beneficial is robustly supported, but the finding of a contrast between the two RTO cases is subject to some observations and caveats. The overall analytical results show that joining PJM offers both higher investment cost savings and higher operational cost savings for South Carolina's utilities than being part of a Southeast RTO.

The lower projected savings for the Southeast RTO case does not reflect any difference in functionality between the two RTOs. Rather, the sources of the lower Southeast RTO savings relate to the findings that PJM offers both more peak-load diversity and more resource diversity. In contrast to PJM, the other potential members in the Southeast RTO have peak loads that are more similar to those of the Carolina utilities (which yields smaller investment cost savings) and a planned 2030 resource mix (e.g., substantial solar generation) that are also more similar to those of the Carolina utilities (which yields lower operating cost savings and off-system sales revenues).

POTENTIAL INVESTMENT COST SAVINGS FOR SOUTH CAROLINA

Joining an RTO also allows utilities to pool their demand across a greater regional footprint. Customers in different locations and states tend to draw peak demand with somewhat different time-of-day and time-of-year profiles, such that utilities within an RTO are able to share surplus generation with others when their demand is below peak demand, and draw on other utilities' surplus when their demand peaks. This diversity in load and resource mix across a larger regional system (one that ideally exceeds the size of challenging weather systems that affect both loads and resource availability) allows region-wide total capacity requirements to be reduced when compared to the case in which each utility manages its own supply and resource adequacy needs independently as in the Status Quo.

These diversity-driven benefits tend to be greatest in large regional systems that have high levels of diversity across the footprint in terms of load patterns, weather patterns, and renewable supply patterns (particularly solar), and resource types (which tend to be affected differently by weather). Moreover, the level of reserve generation capacity (the "resource adequacy requirement" or "planning reserve margin") that must be carried to meet reliability targets can be lower in a large power system because the probability of extreme conditions that simultaneously affect all portions of its footprint is lower, and the options available to address the reliability and grid resilience challenges associated with low-probability events are greater.

For South Carolina, we examined the scale of potential resource investment benefits that can be achieved by reductions in the size of capacity requirements for the different wholesale market reform options. The JDA and EIM scenarios do not offer such benefits, given that each separate utility will continue to utilize status-quo practices for meeting their individual installed capacity requirements and resource adequacy needs. Under the Southeast RTO and PJM RTO scenarios, we examine the scale of diversity benefits that can be achieved by examining 11 years of historical demand patterns (2011–2021) in the participating balancing areas within the respective market region, considering the extent to which the coincident peak (CP) load hours across the broader system declines as compared to the non-coincident peak (NCP) of each utility area considered separately. For more details see Appendix A and Appendix B.

Based on this load diversity analysis, we find that South Carolina capacity requirements could be expected to be reduced by 3.1% in the Southeast RTO case and by 6.6% in the PJM RTO case, as shown in Table 12. The PJM RTO option offers higher reductions in the installed capacity requirement due to greater peak-load diversity between the Carolina utilities and the PJM footprint (as compared to the lower peak-load diversity between Carolina and the rest of the Southeast). In both RTO cases, the Planning Reserve Margin is reduced compared to the Status Quo due to the ability to carry less capacity to meet the same reliability standards when operating across a larger footprint as mentioned above.

These installed capacity requirement reductions can be translated into investment cost savings using an approximate cost of capacity, converted to an annualized cost basis. As shown, the Southeast RTO scenario would offer approximately $120 million in annual investment-related cost savings to South Carolina's customers. If the Carolina utilities joined PJM, these investment cost savings are estimated to be approximately $200 million annually. Both of these RTO-related investment cost savings due to load diversity are likely to increase over time as the Carolina utilities add more solar generation to the footprint, which increases the value of geographically diversified regional loads and resource mix.

TABLE 12: POTENTIAL INVESTMENT COST SAVINGS FROM REDUCED CAPACITY REQUIREMENTS DUE TO LOAD DIVERSITY

Scenario achieves capacity investment savings?			No	Yes	Yes
Projected 2030 Peak Load of SC Utilities	(MW)	[1]	17,748	17,748	17,748
Load Reduction Relative to Status Quo	(%)	[2]	0%	3.1%	6.6%
2030 Regional Coincident Peak Load of SC Utilities	(MW)	[3]	n/a	17,194	16,571
Planning Reserve Margin	(%)	[4]	17.0%	14.7%	14.7%
Capacity Savings Relative to Status Quo	(MW)	[5]	0	1,043	1,759
Annualized Cost of Capacity	($/MW-Day)	[6]	n/a	$308	$308
Annualized Savings from Avoided Capacity	**($ mln/year)**	**[7]**	**$0**	**$117**	**$198**

Sources and Notes:
All dollar values expressed in 2022$.
[1]: Based on 2030 peak load forecast from South Carolina utility IRPs.
[2]: Percent reduction of SC peak load due to load diversity based on regional 4-CP and utility 4-NCP peak loads from 2011-2021 historical gross load data from FERC Form 714, as shown in Appendix A.
[3]: [1] × (1 − [2]).
[4]: For Status Quo/JDA/EIM: SC utilities' target reserve margin from IRPs.
For Southeast RTO/PJM RTO: RTO reserve margin based on PJM historical target reserve margins.
[5]: [2] × (1 + 17%) − [4] × (1 + 14.7%).
[6]: Inflation adjusted PJM 2023/2024 BRA Gross CONE.
[7]: [5] × [6] × 365.

Beyond the savings from peak-load diversity, additional investment cost savings likely will accrue from diversity of renewable generation profiles within larger geographic regions. To illustrate, consider a winter-peaking utility that invests in new solar plants. Winter peak hours occur during the early morning and late evening. If planned in isolation, the utility's solar resources provide no reliability value. The utility would therefore have to invest in alternate sources of supply to ensure resource adequacy. Consider, however, that the broader regional market peaked during daytime summer hours. If resource planning were conducted at this regional level, then the utility's solar resources would have significant resource adequacy value, and could provide that value to the utility by decreasing the capacity it would otherwise have to invest in or retain within the regional market.

The South Carolina utilities are all such winter planning systems, which means the majority of their resource adequacy risks occur during the winter without the benefit of solar generation.[113] As a result, the resource adequacy value of the 5,640 MW nameplate of solar generation in our

[113] See Duke Energy Carolinas, 2022 South Carolina Integrated Resource Plan Update, Accessed February 20, 2023; Dominion South Carolina, 2023 Integrated Resource Plan, January 30, 2023; Astrape Consulting, Reserve Margin and Effective Load Carrying Capacity (ELCC) Study, prepared for Santee Cooper, December 5, 2022.

2030 South Carolina case is very close to zero. By contrast, PJM remains a summer peaking system in which the resource adequacy value of solar is expected to remain above 20% for the next decade.[114] If the Carolinas were to join PJM, the resource adequacy risk would shift mostly to summer peak periods. However, without a more extensive evaluation using the effective load carrying capability (ELCC) method, it is difficult to know precisely the value of Carolina solar in a PJM participation context. Moreover, the ELCC value of solar in PJM is a function of both aggregate load shapes and the level of solar deployment, which means there is inherent uncertainty about the future resource adequacy value of solar resources. However, conservatively assuming a 10% ELCC value for Carolina solar resources in 2030 in the PJM participation context, the 5,640 MW of projected solar generation in our study would be worth 564 MW in resource adequacy terms, which (at the capacity values assumed in Table 25) would yield an additional annual investment cost savings of $63 million for South Carolina customers.

The Southeast RTO option may offer a similar value, but without the system-wide ELCC analysis that PJM has already performed for its system, it is difficult to know. However, because the Southeast is expected to develop a significant amount of solar resources and tends to have a heating and cooling demand profile more similar to that in South Carolina, the resource adequacy value of Carolina solar resources within a Southeast RTO will likely be lower than their value in PJM.[115]

We recommend that, prior to finalizing a decision to pursue an RTO, South Carolina policymakers conduct an ELCC study to assess the reliability value of solar in the broader RTO context relative to South Carolina alone.

Investment savings due to load diversity alone, however, explains only a portion of potential benefits and does not capture the cost savings from having access to a market with pooled capacity resources. These additional market benefits are discussed in Section III.E and Appendix B.

SUMMARY OF COST/BENEFIT ANALYSIS OF WHOLESALE MARKET REFORMS FOR SOUTH CAROLINA CONSUMERS

Combining benefits from operational savings, benefits from investment cost savings, and estimated costs to administer wholesale market reforms, we estimate that some of the wholesale market reforms offer significant benefits for South Carolina consumers through

[114] PJM, December 2022 Effective Load Carrying Capability (ELCC) Report, January 6, 2023.

[115] Georgia Power, Georgia Power's 2022 Integrated Resource Plan, Docket 44160, November 17, 2021.

market reform savings that significantly exceed their costs. As shown in Table 13, full RTO-based market reforms (or alternatives that include both day-ahead and real-time energy markets as well as a regional resource adequacy framework) offer significantly higher net benefits, ranging from $140 million to $360 million annually. On the other hand, both JDA and EIM options may offer benefits that only modestly exceed JDA and EIM administrative cost—although the simulations do not capture certain real-time market challenges (such as intra-hour balancing), which would mean the simulations understate these real-time market benefits.

TABLE 13: ESTIMATED 2030 BENEFIT AND COSTS OF WHOLESALE MARKET REFORMS FOR SOUTH CAROLINA (IN 2022$ MILLIONS/YEAR, RELATIVE TO STATUS QUO)

	Operational Savings [A]	Investment Cost Savings [B]	Administrative Costs [C]	Annual Net Benefit [D]
Carolinas JDA	$10–$13	N/A[116]	$9	**$1–$4**
Southeast EIM	$22–$27	N/A[116]	$18	**$4–$9**
Southeast RTO	$87–$106	$94–$117	$40	**$140–$183**
Join PJM RTO	$163–$200	$158–$198	$36	**$285–$362**

Notes:

[A] and [B]: Values are from Section II.G. The real-time market benefits, which represent all of the JDA and EIM benefits, will be understated because the market simulations do not fully capture real-time challenges, such as intra-hour load following.

[C]: Values are from Sections II.C, II.D, and II.E for JDA, EIM, and the two RTO reform scenarios, respectively.

[D]: [A] + [B] − [C].

116 Capacity investment benefits similar to those from RTO participation could be enabled through the creation of a region-wide resource adequacy framework, such as the new Western Resource Adequacy Program (WRAP), as noted earlier.

H. Recommendations for Wholesale Market Reforms

Based on these findings regarding wholesale market reforms, we recommend that South Carolina consider immediately initiating processes to:

- Join an existing RTO (i.e., PJM), coordinating with North Carolina policymakers (South Carolina would retain authority over the current vertically integrated utility model and resource planning framework, including any potential reforms); or
- Provided that neighboring states and utilities show interest, initiate multi-state efforts to create a new Southeast RTO market; or
- Pursue both an EIM and joint regional resource adequacy program without entering an RTO framework. This option could be achieved by joining with PJM in a non-RTO partnership (ideally together with North Carolina), or with other interested neighboring states and their utilities; and
- Authorize the PSC to review and approve each utility's regional integration plan subject to defined criteria and timelines. [117]

[117] As two examples of legislation in other states, Colorado Senate Bill 21-072 and Nevada Senate Bill 448 establish relevant authorities, timelines, and evaluation criteria for regional market integration. Both states offer relevant experience for South Carolina given their similar, vertically integrated utility models and reliance on integrated resource planning under state regulatory oversight. Source: General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, (2021), signed June 10, 2021.

III. Resource Planning and Competitive Investment Reforms

A. Overview of Potential Resource Investment Reforms

Currently in South Carolina, vertically integrated utilities are responsible to serve the supply needs of customers within their respective service territories, and hence are the entity conducting integrated planning to identify, build, own, or (in some cases) contract for energy supply resources, subject to PSC oversight and approval. The utilities' prudently incurred investment costs are then incorporated into the rate base and are recovered in customers' retail bills along with a return on investment.

Resource planning and completive supply investment reforms, as illustrated in Figure 15, would seek to achieve greater statewide coordination or a more competitive approach to selecting and building resources. A competitive approach could allow customers to benefit by allowing them to select the lowest-cost provider of new generation, batteries, demand response, or other supply resources, including from IPPs if they can offer wholesale power at a lower price than the utility. Competitive reforms would leverage competition to drive down capital costs, increase the value of existing capacity, expand low-cost demand response and energy efficiency options, guide cost-effective resource retirement decisions, and ultimately reduce customer costs. The reforms we examine range from incremental to foundational, and consider:

- **Introducing a statewide IRP across all South Carolina utilities**, under which utilities, the PSC, or other state agencies would conduct resource planning on a joint basis with the goal of informing policy, pooling resource adequacy needs for cost savings, or making improved investment choices on a statewide basis;
- **Expanding the role of competitive solicitations within utility IRPs,** so that IPPs, distributed resource aggregators, and other third-party resource developers would have increasing opportunities to propose resources within competitive resource solicitation processes. A state agency or independent evaluator would select the winning resources, with third-party developers being awarded a contract to develop a portion of needed supply resources if they can do so at a lower cost than the incumbent utility. South Carolina is already in the early stages of gaining experience with competitive solicitations based on provisions in the 2019

Energy Freedom Act, experience that can inform ongoing enhancements to improve effectiveness and transparency. Participation in an RTO can further improve the effectiveness of such a program;

- **Transitioning to partial or full reliance on competitive supply investments**, a model under which resource supply investments are attracted by competitive market prices, thus shifting future investment decisions and investment risks to resource owners (shifting away from integrated planning and regulated cost recovery). Full reliance on competitive supply investments can become a meaningful option for South Carolina in the event that the state begins participation in an RTO with a sufficiently robust investment model; and
- **Securitization of costs associated with retiring thermal assets**, which offers one option for managing the financial arrangements associated with utility-owned thermal assets that are no longer cost-effective to continue operating but whose undepreciated investment costs have not yet been recovered from customers through rates.

South Carolina can implement these reforms under state authorities without any cooperation or coordination with other states. However, for the state to have a meaningful path for full transition to competitive supply investments, it would first need to begin participation in a regional RTO through which the transparent signal of resource needs and associated prices can be expressed.

FIGURE 15: POTENTIAL ROLE OF COMPETITIVE SUPPLY INVESTMENT REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo: Vertically Integrated Utility	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Resource Planning & Competitive Investments	**Supply Investments** • IPPs: Can develop new resources (competing on price)			

Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

B. Status Quo with Utility Integrated Resource Planning

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

Generation investment decisions in South Carolina today are primarily undertaken by the vertically integrated utilities, as mediated through the Integrated Resource Planning (IRP) process. An IRP combines investments in generation, energy efficiency, and demand side management to meet changes in load over a 15-year forecast (accounting for generation retirements). An IRP compares a set of resource portfolios that each meet customer needs. These portfolios are compared using economic and financial analysis, reliability and risk evaluations, environmental assessment, and other considerations related to the public interest. Public comment is required for IRPs to ensure they consider stakeholder perspectives and are potentially refined in light of feedback.

South Carolina requires its electric utilities to prepare integrated resource plans at least every three years (with annual updates).[118] Following 2019's Act 62, IRPs from the investor-owned utilities are reviewed for approval by the Public Service Commission after an open comment process.[119] South Carolina law provides that "*The commission shall approve an electrical utility's [IRP]… if the Commission determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed.*" Through these IRP processes, utilities propose and the PSC approves plans to build or procure new generation resources, and retire older generation resources. The utilities subsequently receive approval to build generation through the CPCN process. Utilities can then allocate prudently incurred investment costs required to develop the selected resources to ratepayers, including recovering an approved rate of return on the capital invested.

Historically, the South Carolina IRPs have focused on self-build generation rather than considering contracts with IPPs or competitive solicitations, and have featured limited coordination among South Carolina utilities.[120] Going forward, based on reforms in the 2019 Energy Freedom Act, competitive solicitations may play a greater role (see Section III.D below).

ADVANTAGES OF STATUS QUO APPROACH

IRP is a central planning process for generation investment; in comparison to a decentralized model with many competing actors, IRP allows for coordination of all infrastructure investment across every generator in the fleet and every transmission facility in a utility's footprint. New generators can be built on the site of recently retired generators (saving on interconnection and other costs and reducing job displacement from retirement), and the transmission interactions

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[118] Specifically, the South Carolina Public Service Commission currently requires preparation of IRPs every three years that plan system reliability on a 15-year horizon. The IRP process as laid out in SC Act 62 includes: (1) forecasting future electric demand; (2) identifying goals and requirements of the process; (3) developing a set of resource portfolios to meet the demand and goals; (4) evaluating those portfolios across cost, fairness, and environmental dimensions; and (5) choosing a preferred plan. S.C. Code § 58-37-40; see also U.S. Environmental Protection Agency, "State Energy and Environment Guide to Action: Electricity Resource Planning and Procurement," 2022.

[119] The IRP of Santee Cooper must include additional specific elements: (a) an analysis of long-term power supply alternatives, with PSC evaluation of self-build generation and transmission options compared with various alternatives, including power purchase agreements, market purchases from an RTO, and joining an RTO; (b) a PSC analysis of any potential cost savings that might accrue to ratepayers from the retirement of remaining coal generation assets; and (c) evaluation of a resource portfolio that meets a net zero carbon emission goal by the year 2050.

[120] Duke prepares a combined IRP among its South Carolina and North Carolina utilities.

of one generator addition or retirement can be played off the deployment of another generator. These interactive effects can, if effectively deployed, lead to cost savings.

While the IRP process in South Carolina is focused primarily on electric reliability and financial concerns (costs and benefits, but also financial risks), it takes into account non-financial considerations, such as environmental impacts, as well. The IRP process can be used to help accomplish the state's broader social goals related to jobs, affordability, and the distribution of impacts on different communities.

DISADVANTAGES OF STATUS QUO APPROACH

Today's utility IRPs feature little regional coordination among utilities: each resource adequacy analysis (demonstrating that sufficient generation is planned for to meet reliability targets) is limited to the resources of that company (and in the case of Duke, across multiple states). This necessarily results in a higher quantity of needed generation, both because the installed reserve margin must be higher for the utility to handle operational risks on its own, and because regional diversity benefits are not enjoyed.

If focusing on self-build, historical IRPs have offered a more limited set of options for consideration compared to what could be considered in a fully competitive model with many potential resource providers identifying and proposing a wider array of projects. For example, a competitive solicitation-based approach could consider utility projects alongside IPP projects, third-party demand response aggregations, imports from outside the state, and a range of short- or long-term supply options. The utility self-build option may be the most cost-effective option in some cases, but not others. In at least some cases, an IPP building under a long-term Power Purchase Agreement (PPA) contract could have access to a lower-cost site, a more cost effective technology type such as cogeneration or demand response, or have more competitive construction terms. Different developers have different outlooks on the energy market and differing hedging strategies, which can impact their perceived risk or risk exposure, and potentially reduce their cost of capital. Such options are not possible to consider if the IRP processes do not regularly consider third-party supply options.

The current IRP approach does not have a mechanism through which the utilities in South Carolina and neighboring states can coordinate the timing and volume of capacity investments. A statewide IRP could be used to achieve some level of alignment or coordination. A regional capacity market would go further to create a relatively standardized and liquid exchange through which utilities could manage small surpluses and deficits, for example potentially deferring new plant builds because of a temporary availability of low-cost capacity from a neighboring utility.

Whether opportunities for capacity sharing were identified through a statewide IRP processes or via a fungible capacity market, customers from both utilities would benefit from such an exchange (the selling utility because capacity sales can offset the cost of their supply and the buying utility because the short-term purchase is less expensive than expediting new investment).

Under the current IRP model, customers face the risk of errors or lack of foresight in investment choices. For example, a resource investment that appeared prudent at one time can prove to be costly in retrospect if changes to fuel prices, environmental regulations, or other market conditions undermine the originally expected value proposition and the resource must retire early or stand idle much of the time. Customers would be required to pay for the cost recovery on such an asset as long as the costs were approved and prudently incurred, even if customers are not receiving the originally expected benefits. Finally, under cost of service regulation, utilities are able recover a regulated rate of return on the entire rate base, which provides a financial incentive to make larger capital investments that can be at odds with customers' interest to reduce investment costs while maintaining quality of service and resource adequacy.

C. Statewide Resource Planning Across All Utilities in South Carolina

DESCRIPTION AND RELEVANT CASE STUDIES

In South Carolina, each utility conducts a separate IRP process with no requirement for coordination across the utilities on the selected supply plans. Some other jurisdictions utilize a statewide IRP or similar process conducted or overseen by a government entity in order to achieve state policy goals along with the aims of the IRP in a coordinated manner. Depending on the underlying purpose of the mechanism in each jurisdiction, the process may include modeling to inform specific policy questions; IRP-like assessments to determine the scale of resource needs and preferred resource types on a region-wide basis; and/or competitive solicitations to procure some or all of the needed supply. California, New York, and Ontario all utilize distinct variations of an IRP or IRP-like processes that cross all utility areas within the relevant jurisdiction and that are suited to achieving their specific policy aims.[121] Their approaches involve:

[121] See general discussion of these processes in: California Public Utilities Commission, "Utility Scale Request for Offer (RFO),"2021; K. Spees, et al., Qualitative Analysis of Resource Adequacy Structures for New York, May 19, 2020; IESO, Planning and Forecasting Overview, accessed January 12, 2023.

- **California**: The California Public Utilities Commission (CPUC), in coordination with the California Energy Commission (CEC) and CAISO, oversees IRP processes. The IRP process has evolved extensively in the decades since statewide restructuring to meet a variety of policy goals, including to: achieve competition in the electricity sector; ensure resource adequacy needs and manage customers' financial exposure in the restructured environment; and meet state environmental policy goals, including updates in 2018 to meet the provisions of SB 350, the Clean Energy and Pollution Reduction Act.[122] SB 350 outlines emissions reductions targets and requires large utilities to submit IRPs that plan for resource needs and ensure greenhouse gas reductions and clean energy integration.[123] The CPUC, in coordination with CEC and CAISO, and considering commenter input, conducts modeling to identify a Reference System Plan of resources to meet forecasted demand, greenhouse gas, reliability, and RPS requirements. In the second phase of planning, each utility develops individual IRPs consistent with the Reference Plan. The CPUC aggregates these individual plans, assesses system reliability, and recommends a comprehensive Preferred System Plan.[124] In the first two-year iteration of the current process, the Commission approved a plan that calls for utility procurements for 12 GW of new, clean resources by 2030, and no new natural gas plants.[125] Once the procurement plans are approved, each utility conducts competitive solicitations under the oversight of the CPUC and an independent evaluator, contract with the winning resource developers, and pass the costs along to retail customers. This approach incorporates a substantial role for state agencies to define the needed resource mix in the context of state policy goals and with a focus on meeting statewide environmental mandates.
- **New York:** New York's power sector is structured to rely on competitive resource investments that for the most part have been attracted via the NYISO wholesale capacity and energy markets. More recently and going forward, resource investment needs in New York are primarily driven by the State's 100% by 2040 clean electricity requirements, with sub-goals for specific resource types including storage, offshore wind, and other renewables. To meet both reliability and environmental policy goals, New York relies on several state agencies and committees to conduct statewide resource planning and modeling, with primary roles for the

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[122] See California Public Utility Commission, Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP).

[123] California Senate Bill 350, De León, Clean Energy and Pollution Reduction Act of 2015, approved by Governor October 7, 2015.

[124] California Public Utilities Commission (CPUC), Order Instituting Rulemaking Implement Senate Bill 520 And Address Other Matters Related To Provider Of Last Resort, Rulemaking 21-03-011, March 25, 2021.

[125] M. Specht, "The Basics of Integrated Resource Planning in California," Union of Concerned Scientists, May 23, 2019.

New York State Energy Research and Development Authority (NYSERDA) to conduct or support modeling efforts, and the Department of Public Service (DPS) to approve programs and solicitations to meet identified needs and state legislative requirements, evaluating various alternatives in light of legislatively-defined criteria including cost, reliability, equity, and environmental goals.[126] In the case of large-scale incremental resource needs, the DPS approves the details of method of procurement and contract structure and directs NYSERDA to conduct competitive solicitations for the needed resources; NYSERDA selects the winning bidders (subject to DPS approval) and acts as the contractual counterparty; and the costs of supply under contract are then passed to customers of all utilities across the state.

- **Ontario**: Ontario's Independent Electricity System Operator (IESO) is a government agency that takes responsibility for both operating the wholesale electricity markets and for planning and procuring energy in a single-buyer model, relieving utilities completely of planning and procurement responsibility. The IESO models reliability, demand, and resource adequacy annually, and translates the planning needs into procurement requirements, while considering national and provincial policy mandates, costs, and risks. Depending on the timeline of any identified needs, the IESO employs a capacity auction for near-term peak demands; medium- and long-term competitive contract solicitations; and technology-specific Requests for Proposals (RFPs) to secure needed electricity supply. Under this "single buyer" procurement model, all supply resources are developed under contract with the IESO and associated procurement costs are allocated to customers of all utilities as a surcharge on customer bills (no individual contract is tied to a specific utility or its distribution system customers).

POTENTIAL ADVANTAGES

Potential advantages of a statewide IRP process could include:

- If conducted primarily as modeling or informational exercises, statewide assessments can inform policymakers, individual utilities, and the public about the possible implications of a potential policy decision or statewide resource strategy, for example in the context of assessing major environmental policies the consumer cost impacts of which may not yet be known.

[126] See New York Department of Public Service, Order on Implementation of the Climate Leadership and Community Protection Act, May 12, 2022.

- Coordination of planning activities across a larger planning footprint achieves a reduction in the aggregate requirement for resources due to load diversity and a potential small reduction in the installed reserve margin necessary to preserve target reliability.
- Coordinated planning could achieve a more efficient resource selection, timing of entry and retirement, siting, or self-consistent resource mix.
- Potential economies of scale in constructing larger and more efficient assets to serve statewide demand, a benefit that could arise primarily if individual utilities' assessments would tend to procure multiple smaller plants (individually lower cost but collectively a higher cost).
- If statewide IRP is followed by competitive solicitations to meet the defined needs, the benefits could include greater competition and potentially lower cost resource procurements (see more discussion in the following section on competitive IRP reforms).
- If statewide IRP is conducted in the context of full state restructuring (i.e., transition to primary reliance on a competitive investment model and retail choice as discussed further in Section III.E and Section IV respectively), then state-overseen IRP can fill the role of assessing and planning for policy goals that will not otherwise be addressed by a purely market-based construct (e.g., consideration of environmental policy, managing price volatility, employment impact assessments, and equity).

POTENTIAL DISADVANTAGES

Potential disadvantages of statewide IRP processes could include:

- The risk of uneconomic investments remains on the ratepayer for any approved investments.
- Mechanism to hold state planning agencies accountable for decisions is not as clear or well established as oversight of traditional utility cost recovery.
- State agencies may have less information and visibility into each utility's resources, customers, and operations than the utilities themselves.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

The role and benefits that could be associated with a statewide IRP would depend on whether and to what extent the state wishes to pursue other market reforms discussed in this paper to the resource planning and investment model and/or to introduce partial or full retail choice. We therefore suggest that:

- If South Carolina policymakers decide to rely mainly on the historical status quo approach of utility planning, investment, and retail provision, the role and relevance of statewide resource planning would be primarily to provide information and (depending on the design) yield some savings associated with pooling of resource adequacy across a relatively modest footprint. A principal value of statewide IRP would be for the PSC, ORS, and legislature to use regularized or ad hoc studies to offer independent assessments to inform specific policy choices, and/or enhance the PSC's ability to review and scrutinize the separate utilities' IRPs during approval processes.
- If South Carolina opts to incrementally expand the role of third-party resource suppliers and competitive solicitations to meet future needs (as discussed in the following Section III.D), then a statewide IRP process could take on a more substantial role in determining the contours of such a solicitation, including evaluating the desired statewide resource mix and defining the volume or type of supply to be procured by a state agency or the separate utilities.
- Finally, if South Carolina eventually pursues a restructured competitive supply investment model (as discussed in Section III.D below), then a periodic statewide IRP process could be used to identify and assess the need for contracts and resource investments to serve policy goals that will not otherwise be addressed by a purely market-based investment model.

To supplement or replace individual utility IRP processes with a statewide process, the legislature may need to authorize or direct state agencies (likely the PSC) to take on the defined resource planning roles. The legislature would also need to allocate responsibility to the PSC, ORS, separate utilities, or another entity for each element of the planning process: who models resource need, who solicits supply offers to meet statewide need, who approves the statewide solicitations, how an independent evaluator is relied upon, and who is the counterparty for the bids chosen.

We further note that the role of statewide planning may differ for customers of investor-owned utilities, versus customers of public power entities. For IOU customers, the outcomes of any future statewide planning process could be to direct the utilities to self-supply, solicit contracts, sign contracts selected by a state agency, or pass the costs of a state-agency-signed contracts to their customers. For public power customers, the outcomes of any statewide planning process could instead result in informational findings and the option (but not the requirement) to participate in any recommended self-supply or contract solicitation activities.

D. Expanding the Role of Competitive Solicitations in Utility IRPs

DESCRIPTION AND RELEVANT CASE STUDIES

With adoption of the 2019 Energy Freedom Act, South Carolina has authorized (but not required) the use of competitive solicitations for new renewable developments and for assessing the cost-effectiveness of major new generating facilities.[127] Under this new framework, the PSC has new authorities to require the use of competitive solicitations if deemed in the public interest, including the ability of the PSC to hire an unbiased independent evaluator and ensure that a competitive solicitation is conducted under PSC-approved processes. South Carolina is in the early stages of developing and implementing such processes, which are the subject of several ongoing dockets, as well as a soon-to-be-completed all-source competitive procurement in the Dominion utility area.[128] The outcomes of these dockets and early solicitations can help to inform and improve procurement and oversight processes; as can the consideration of best practices and lessons learned from other states' competitive solicitation processes.

In developing and refining solicitation processes, typical considerations include:[129]

- **Determination of the resource need and timing,** such as meeting either reliability requirements (i.e., winter or summer capacity need) while considering policy goals (e.g., by having renewable or battery storage requirements) or other system needs identified in an IRP process.
- **Timeframe and duration of procurements,** including consideration of whether short-term commitments can be considered alongside new resources that could be developed under long-term contracts.

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[127] Specifically, "*The commission is authorized to open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility's balancing authority area if the commission determines such action to be in the public interest.*" South Carolina Office of Regulatory Staff, Summary of the South Carolina Energy Freedom Act, September 2019.

[128] Public Service Commission of South Carolina, Docket No. 2021-93-E, Order No. 2022-27, January 11, 2022.

[129] See additional discussion of competitive solicitation experience and best practice, see: Dr. Fredrich Kahrl, 3rdRail Inc., All-Source Competitive Solicitations: State and Electric Utility Practices, March 2021.; J. Wilson et al., Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement, April 2020.; J. Wilson, Implementing All-Source Procurement in the Carolinas, February 26, 2021.; K. Spees, et al., The Brattle Group, Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint, November 2015.

- **Whether to use technology-specific procurements or consider all-source procurements.** Technology-specific procurements make it easier to compare different technologies on a like-to-like basis but all-resource procurements can typically produce better overall results by allowing consideration of more options, broadening competition, and allowing consideration of complementary resources.
- **Whether and how to stipulate standard contract terms and volumes**. Standardized contract forms enable the solicitation to more readily compare offer prices across different bidders, but may implicitly restrict competition of the specified contracts or product ratios (e.g., ratio of energy to capacity) in a way that is tied too closely to an assumed resource type. To more readily compare many alternative technologies, one option is to define a total procurement need across clearly defined products and allow bidders to self-select their proposed product mix.
- **Assessment processes and criteria.** These typically focus on total net resource cost to meet the defined adequacy need, and can utilize a modeling assessment to project total net cost of service depending on the portfolio of resources that would be selected from the procurement.
- **Role of an independent evaluator and other controls to ensure unbiased resource selection.** Best practice for supporting fair evaluation includes transparent rules and processes and an independent evaluator hired by a state agency that selects the winning resources. Particularly in solicitations where utilities are allowed to propose self-supply processes, the role of a state agency with independent evaluator support becomes critical to avoid the opportunity or perception that utility-proposed projects may be unfairly advantaged.

Some states and utilities are utilizing all-source competitive procurements as a tool to discover market prices, select a lower-cost resource portfolio, and attract innovative projects. Notable examples where this strategy has been implemented include:

- **Xcel Colorado:** Xcel administers a two-phase process that the Colorado Public Utilities Commission (COPUC) reviews. In Phase 1, the utility determines needs, resources, carbon costs, and provides scenarios to meet those needs instead of a portfolio of resources. Phase 2 includes an all-source RFP with bidding for intermittent, dispatchable resources and an independent evaluator. The utility may bid up to 50% of the defined need with self-supply projects. Selected bids are then included in system planning model analysis. A 2017 all-source procurement attracted 417 bids, with bid prices including $0.017/kWh for wind, $0.023/kWh for solar, and $0.03/kWh for solar-plus-storage (much lower than prevailing $0.126/kWh residential prices at the time).[130] The selected portfolio was estimated to save customers over $200 million compared to the utility's original preferred portfolio.[131]

- **Northern Indiana Public Service Company (NIPSCO):** NIPSCO conducted all-source RFPs to inform their IRP, attracting 90 bids in 2018 and 182 bids in 2021. Average bid prices from NIPSCO's 2018 All-Source Competitive Solicitation (ASCS) were on the lower end or below the low end of the range of prices from the prior 2016 IRP process, which did not utilize ASCS.[132] The result of the all-source procurement identified resources offering supply at prices at less than half of the cost to operate the utility's existing coal fleet.[133]
- **El Paso Electric (EPE):** EPE issues yearly All Source RFPs to obtain short term and/or long-term cost effective resources to meet capacity needs identified through initial resource planning studies. EPE evaluates proposals in two stages, first on levelized cost of electricity by type of resource and type of proposal, shortlists bids, and then asks for Best and Final offers to determine optimal winning bids. The process is then evaluated by an independent evaluator.[134]

POTENTIAL ADVANTAGES

The potential advantages of incrementally expanding the role of competitive solicitations into utility or statewide IRPs include:

- Increased competitive pressures and opportunity to identify lower-cost providers and sites.
- All-source solicitations create opportunity to further reduce costs by identifying an overall lower-cost resource mix (in addition to applying the competitive pressures on individual resource costs). All-source solicitations can attract innovation from new technologies that might not otherwise have been considered in the IRP, and allow complementary technologies (such as batteries and solar) to offer their separate or combined value in distinct offer structures.

130 Procurement, Xcel Energy Achieves Record-Low Procurement Costs, June 5, 2021.

131 Rocky Mountain Institute, How to Build Clean Energy Portfolios: A Practical Guide to Next-Generation Procurement Processes, 2020.

132 Dr. Fredrich Kahrl, 3rdRail Inc., All-Source Competitive Solicitations: State and Electric Utility Practices, March 2021.

133 Utility Dive, NIPSCO to replace coal with 2.3 GW of solar, storage in latest RFP, October 9, 2019.

134 El Paso Electric, 2021 All Source Request for Proposal for Electric Power Supply and Load Management Resources for Texas, December 3, 2021.

- Provides a "market test" and a visible competitive price against which regulators and the public can validate timing and cost of IRP-identified investment decisions, retirement decisions, and resource mix.
- Can increase transparency and stakeholder involvement. Publication of solicitation offer prices, volumes, and other statistics can inform other utilities, public power, and end-use consumers in the state about the availability, technologies, and potential price points that could inform their own separate bilateral agreements.
- If considering short-term contracts with existing resources or imports (alongside consideration of long-term contracts for new resources), this can sometimes identify low-cost options available for a temporary period, thus deferring the need to pay the full cost of new resources for a time.
- Regularized state processes following best practice and independent evaluations can spur and retain investor interest, such that they will be incentivized to develop a robust pipeline of projects for potential consideration.

POTENTIAL DISADVANTAGES

The potential disadvantages of expanding the role of competitive solicitations into utility or statewide IRPs include:

- Can introduce complexity into IRP processes, procurement processes require thoughtful design, oversight, and implementation to be successful.
- Complexity and protections required to ensure fair evaluation of utility self-supply versus third-party proposed projects; for example by assigning responsibility for managing the process and resource selection to a state agency or independent evaluator.
- Utilities have an incentive to pursue self-supply rather than engage in long-term contracts, given that: (a) self-supply creates opportunity to expand the rate base and associated shareholder returns; and (b) long-term contracts have the effect of imposing "imputed debt" costs on the utility, similar to impact of taking on debt.[135]
- Soliciting offers for a well-defined, standardized product or a single resource type simplifies selection to a simple evaluation of price, but removes the benefits of being able to assess a wider array of technologies with different value attributes.

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[135] See discussion of imputed debt methodology: Rhode Island Public Utility Commission, Information request AG-2-1, accessed February 15, 2023.

- Evaluating bids and assessing new technologies with highly divergent value propositions can be time consuming and may sometimes be less amenable to standardized assessment processes; new evaluation metrics are needed to compare renewables and storage with traditional resources or determine what portfolios of technologies to consider in a grouped fashion.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

South Carolina may benefit from expanding the role of competitive, all-source solicitations to meet defined needs within individual utility or any future statewide IRP processes. South Carolina is presently and will in the near future gain more experience with competitive renewable and all-source solicitations, experience that (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved by options such as:

- Requiring (rather than the current "allowing") future supply needs identified in IRP to be met through all-source competitive solicitations.
- Determination of whether utility self-supply projects would be allowed to compete alongside third-party suppliers and, if so, what mechanisms would be implemented to ensure that all bids are considered on an equal basis. For example, by placing primary responsibility for conducting solicitations with a state agency and with support from an independent evaluator.
- Determining whether state agencies or utilities will be the entity required to sign contracts with winning bidders. In the latter case, determining how to compensate utilities for the cost of contract management and effects of "imputed debt."
- Determination of whether and how electric cooperatives, municipally owned utilities, and other public power entities can participate in resource selection and receive a share of the selected supply, potentially on an opt-in basis.
- Establishing and refining regularized processes consistent with best practice, including transparent timelines, assessment criteria, and sufficient flexibility to consider a wide array of potential proposed projects.

E. Transition to Partial or Full Reliance on Competitive Supply Investments

DESCRIPTION AND RELEVANT CASE STUDIES

In the 1990s and early 2000s, many U.S. states and international jurisdictions restructured to transition from the vertically integrated utility model, with the goals of using competition to drive down costs and support sector innovation.[136] Full transition to a competitive investment model involves shifting all decision-making around future resource investments away from the utility IRP model, and instead relying on competitive "merchant" resource developers to build needed supply resources. Under the competitive investment model, private companies are incentivized to build new generation, demand response, or storage resources on the basis of a competitive market price, or else based on bilateral contracts voluntarily struck with customers or competitive retail providers.

PJM's capacity market results illustrate the advantages and disadvantages of transitioning to a competitive investment model, in particular the advantages of relying on competitive forces to attract a diverse set of resources and keep costs low.[137] While the PJM capacity market serves an important role in pooling resource adequacy in both vertically integrated and restructured regulatory frameworks, it plays a unique and critical role in influencing resource investment in the restructured context. Over the last decade of the PJM capacity market, prices have remained quite low (approximately 27% of the estimated cost of building of new generation) but the market has attracted approximately 176 GW of incremental low-cost supply from non-traditional resources including demand response, uprates to existing generators, net imports, and energy efficiency.[138] More recently as additional coal plant retirements have created the need for new supply, the capacity market has attracted approximately 35 GW of new generation, primarily gas combined-cycle plants (even though market prices have never risen to more than 60% of the

[136] See, for example, a detailed history of restructuring across the six New England states. Reishus Consulting, Electric Restructuring in New England—A Look Back, prepared for the New England States Committee on Electricity (NESCOE), December 2015.

[137] Several other options for attracting market-based investments for resource adequacy exist around the globe, but the capacity market model is the primary option utilized in the U.S. RTO/ISO markets. For a discussion of alternative structures, see J. Pfeifenberger, et al., A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs, September 2009.

[138] PJM, 2022/2023 RPM Base Residual Auction Results, accessed February 20, 2023.

estimated cost of new entry, CONE).[139] PJM's capacity market successfully achieves twin design objectives: accounting for pooled resource adequacy needs, and attracting new supply in a low cost environment. It accomplishes this without interfering in the IRPs of vertically integrated utilities. The PJM capacity market's success at attracting new entry on a competitive basis stands in contrast to other capacity market designs (such as MISO's) that lack certain design features to achieve these objectives. Therefore, South Carolina policymakers interested in a fully competitive resource investment model should seek an RTO capacity market that is designed to be flexible to facilitate different participation models (vertically integrated or restructured) while achieving these important design objectives.

The primary criticisms of the PJM capacity market have focused on the pace of changes to market rules as they are updated to reflect emerging reliability needs; administrative judgement and estimation errors with respect to procurement parameters (particularly with respect to peak load over-forecasting); and the lack of mechanisms within the market to reflect states' environmental policy goals.[140]

States representing approximately 57% of all U.S. energy demand rely on competitive supply investments to meet at least a portion of their resource adequacy needs.[141] These are the same states that have introduced some level of competition into the retail market, given the structural linkage between competitive supply investments and retail choice (i.e., for customers to exercise a meaningful level of choice in their power supply, they must be able to choose from among many potential sellers of power). At the conclusion of a full restructuring transition, segments of the electricity supply chain considered to be natural monopolies (transmission and distribution) are continued to be regulated by the state while the competitive portions of the electricity supply

[139] Note this is referencing the base PJM RTO clearing price, while locational capacity prices have risen beyond this level due to increased need in capacity constrained areas of PJM. See PJM, 2022/2023 RPM Base Residual Auction Results, accessed February 20, 2023.

[140] These concerns are among the reasons that most states and large utilities relying on vertically integrated IRP models in the PJM region have chosen to opt out of capacity market participation under the Fixed Resource Requirement Alternative (FRR), even while they fully participate in the RTO energy market and transmission planning processes. Other RTOs such as MISO and SPP also offer many of the same advantages of the PJM RTO in terms of energy market coordination and regional transmission planning, but do not (yet) offer capacity market that has proven to attract supply investments when needed. See PJM, Securing Resources Through the Fixed Resource Requirement, September 23, 2022.

[141] Energy Information Agency (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, accessed February 8, 2023.

chain (generation investment, generation operations, and retail supply) are provided by a mix of competitive companies.[142]

Transitioning from a vertically integrated model to a competitive investment model involves foundational restructuring of the electric sector. The primary elements of such state restructuring activities typically includes:

- **Separating the customer bill into distinct components representing each portion of the electricity value chain.** This step clarifies and distinguishes the portions of the customer bill that can be subject to competition (generation investments, energy generation costs), from those that will continue to be subject to traditional regulatory oversight (transmission, distribution, or other state-regulated programs or line items for non-bypassable charges).
- **Identifying a market-based model for attracting competitive supply investments when needed.** The most relevant option for South Carolina would be an RTO-operated regional capacity market, such as those operated by PJM, ISO-NE and NYISO. MISO's capacity market offers some of the same features of these others, but has not (yet) demonstrated capability to attract merchant supply investment when needed.
- **Addressing the ownership arrangements for existing generation supply developed under regulated cost recovery,** to achieve a structurally competitive generation supply segment. Distributing ownership of existing supply resources across multiple generating companies has the effect of ensuring that neither the incumbent utility nor others hold a monopoly share of supply resources, and subjects these players to competitive pressure. Options for addressing ownership arrangements include:
  - **Generation divestiture** is a common strategy used in restructuring states and requires incumbent utilities to sell some or all of their generation assets to competitive generation companies.[143] The advantage of divestiture is that it is the fastest path to full restructuring

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[142] For clarity, this discussion omits a substantial amount of complexity and variation in how these segments of industry can interact. For example, some level of competition can be introduced to transmission and distribution, even though they are predominantly regulated as natural monopoly systems. Further, many utilities even in restructured states retain a role in the generation segment through unregulated generation affiliates, by implementing state-directed contracting, implementing state policy programs, or other similar activities. Finally, even in states that rely partly or primarily on a restructured model with competitive investments, the states often exercise their authorities to influence the resource mix through utility-directed or agency-solicited contracts and investments.

[143] Used as a partial or full strategy in many states including California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, New York, Texas, as well as internationally. See discussion in J. Lazar, P. Chernick and W. Marcus, and M. LeBe (Ed.), Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project, January 2020 and Reishus Consulting, LLC, Electric Restructuring in New England—A Look Back, prepared for New England States Committee on Electricity (NESCOE), December 2015.

and subjecting all generators to full competitive pressures; the disadvantage is the risk that poorly executed or poorly timed divestitures could sell off assets at below their true value or forfeit long-run customer value that could have been realized.

- **Retaining utility or government ownership of selected assets,** particularly for assets that have a high (or uncertain) going-forward market value, whose investment costs are already or primarily paid off, or whose future operating/retirement decisions have material policy implications that may not be fully incentivized by market forces alone. For example, existing large hydroelectric and nuclear generation assets with low operating and going-forward costs could continue under utility or government ownership and operation as a means to ensure that full market value (market price minus low resource going-forward costs) can be returned to consumers over the long term.
- **Asset transfer to an unregulated utility affiliate** is an option that has been used occasionally in which a regulated utility would be allowed to continue to own some or all of the generation assets, but separate them into a different "merchant generation" company affiliate.[144] The state regulator would approve an estimated market value at which the new merchant generation affiliate company could compensate ratepayers for the generation assets. The merchant generation company would then be allowed to operate and collect market revenues associated with the assets for their remaining asset life. The merchant company would be required to be functionally separated from all regulated businesses sufficiently to separately track operating costs and prevent utility self-dealing.[145]

- **Recovering legacy utility investment costs.** At the time of asset divestiture or transfer, proceeds from the sale are returned to customers as an offset to rate base and customer bills. If the proceeds from asset divestiture exceed the remaining asset value in rate base (also referred to as "book value," or remaining undepreciated investment costs that the utility has not yet recovered from customers), then the additional value arises on the customer bill as a discount or credit on the bill for a determined period. If proceeds from divestiture are below remaining book value, the remaining stranded asset cost is passed to customers as a

[144] This option was utilized to some extent in Ohio, Pennsylvania, New Jersey, and Maryland. In these jurisdictions, the distribution utilities' merchant generation affiliates have remained some of the largest generation owners even two decades after restructuring. See J. Lazar, P. Chernick and W. Marcus, and M. LeBe (Ed.), Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project, January 2020.

[145] See a discussion of conditions that can give rise to utility self-dealing and options for mitigated potential abuses in M. Harunuzzaman, Ph.D. and K. Costello, State Commission Regulation of Self-Dealing Power Transactions, The National Regulatory Research Institute, NRRI 96-06, January 1996.

"competitive transition charge."[146] States have utilized a wide range of approaches to managing these transition charges, including by allowing securitization (as discussed in more detail in the following section) or amortizing costs over a pre-determined transition period.

POTENTIAL ADVANTAGES

The potential advantages of transitioning toward competitive supply investments include:

- Shift investment, siting, and construction risks from consumers to private companies.
- Use of competitive pressures and profit incentive to drive sector innovation, attract more suppliers, and reduce costs.
- Enhanced ability to attract low-cost resources from third-party suppliers, including demand response, uprates to existing assets, industrial cogeneration, imports, or other unique opportunities not typically available or visible to single utility.
- Full divestiture (rather than partial divesture or asset transfer to a merchant affiliate) offers the fastest pathway to a fully competitive generation segment.
- Partial divestiture can be used to segment generation assets between those that are attractive to divest versus retain under utility or government ownership.

POTENTIAL DISADVANTAGES

The potential disadvantages of transitioning toward competitive supply investments include:

- If transition is completed without an adequate market-based system for attracting competitive supply investment when needed (such as a well-functioning capacity market), then insufficient future supply investments could be made to meet reliability needs.
- Poorly executed or poorly timed asset divestiture poses risk that customers may recover less than the full long-term value of the assets in question.
- Use of asset transfer to a new merchant utility affiliate risks under-valuation of asset value (not subject to full competitive test of potential asset value) and may create future incentives for utility self-dealing or preferential access with the affiliated merchant generation company.

[146] For example, see Pennsylvania utilized such a competitive transition charge to keep utilities whole for stranded investments as of the time of sector restructuring. See 66 PA Cons Stat § 2808 (2016), For a comprehensive discussion of stranded costs in restructuring, see Congressional Budget Office, Electric Utilities: Deregulation and Stranded Costs, CBO Paper, October 1998.

- Under the full divestiture approach, a large portion of utilities' present scope of business and future opportunities for revenue and profits would be curtailed (though investors would be made whole for all investments made to date).
- Potential for cost shifting among customer classes, depending on how any stranded asset costs are allocated.

BENEFIT-COST ASSESSMENT OF TRANSITION TO PARTIAL OR FULL RELIANCE ON COMPETITIVE SUPPLY INVESTMENTS

To examine the potential scale of benefits that could be achieved from competitive investment reforms, we developed an indicative calculation of future resource investment costs under a range of scenarios and sensitivity assumptions. The primary assumption underlying this analysis is that the introduction of competitive investment reforms is implemented in a fashion that follows best practice for maximizing competition in a resource-neutral fashion, appropriately manages transition risks, and hence achieves the theoretical benefits. Due to this and as discussed above, we use the PJM capacity market as an example.

The additional cost savings that arise from having access to a market include: (a) the ability to sell net capacity surpluses into the market thus offsetting customer costs; (b) ability to access cheaper capacity due to market competition; (c) ability to attract new low-cost capacity resources such as demand response and uprates that may otherwise not be identified; and (d) the ability to right-size capacity holdings every year more easily through market purchases instead of new-builds.

The three scenarios we compare include:

- **Status Quo:** In this scenario, we assume that future supply investments continue to be made under the IRP model. The quantity of new resource investments that will be needed also is consistent with the most recent utility IRP peak load forecasts, load growth, and assumes that utilities will maintain reserve margins consistent with minimum reliability requirements in order to manage year-to-year supply-demand uncertainties (this range is consistent with historical resource planning levels).[147]
- **Incremental Participation:** In this scenario, we assume that utility IRP continues as under the Status Quo paired with an incremental participation in the capacity market. In this scenario

[147] See Duke Energy Carolinas South Carolina, 2022 Integrated Resource Plan Update, 2022; Duke Energy Progress, 2020 Integrated Resource Plan Modified, 2020; Dominion Energy South Carolina, Inc., 2023 Integrated Resource Plan, January 30, 2023; Santee Cooper, 2020 Integrated Resource Plan, December 23, 2020.

the total quantity of supply investments needed in the future is reduced due to the load diversity benefits of a regional RTO as explained in Section II.G above. In addition, the utilities are assumed to use the RTO capacity market to balance and "right size" supply needs. Supply excesses can be sold into the market at the market price and the associated revenues returned to customers as an offset to capacity investment costs.[148] Similarly, any supply deficits could be procured from the RTO market at the market price.

- **Full Participation:** In this scenario, we assume that future resources are developed fully under a competitive supply investment model and no new IRP-based, regulated-utility investments are made. In this scenario, capacity needs are procured and any capacity surplus are sold in the PJM capacity market at the market price.

To provide ranges for these three scenarios we developed a Reference Case, High Case, and Low Case, as shown in more detail in Appendix B. We compare the Incremental and Full Participation reform scenarios to the Status Quo and report net benefits. These two reform scenarios are the same in the initial years (2023–2029) because legacy investments have already been made regardless of how South Carolina decides to participate in the capacity market in the future and the scenarios diverge in the later years (2030 onward) once new build capacity is needed. The resulting range of benefits of participating in an RTO with a competitive regional capacity market are presented in Figure 16 below.

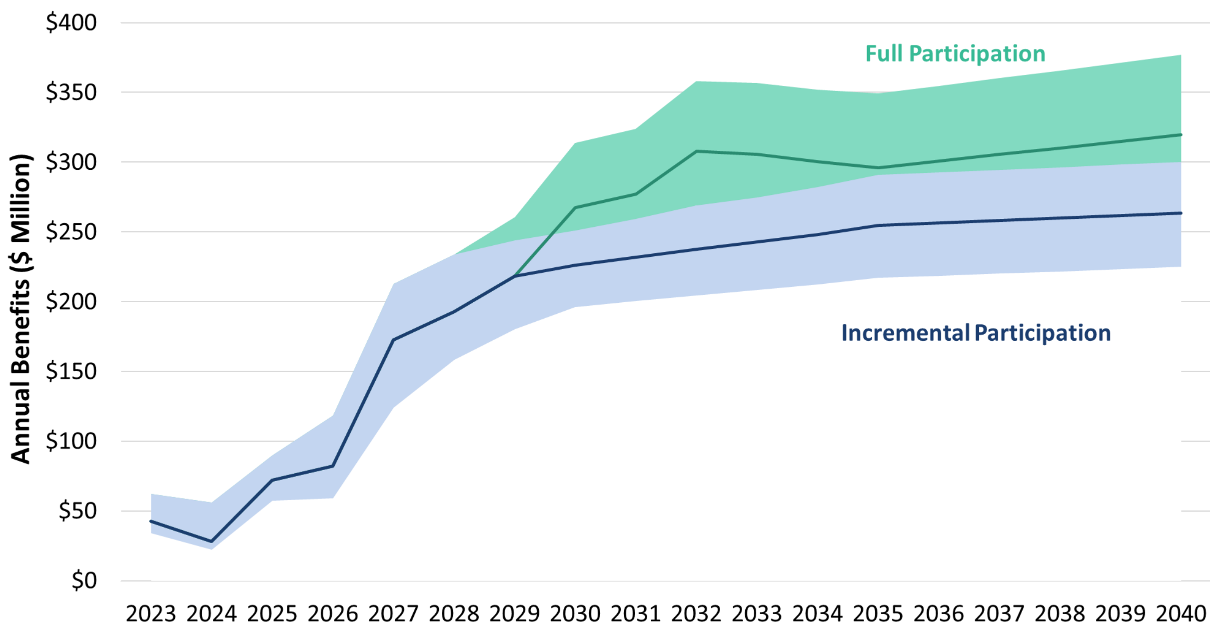
As illustrated in the figure, a portion of the benefits of participating in a regional capacity market would be achieved immediately upon integration and would be realized even if the state continues to rely fundamentally on utility IRP to drive future resource investments. These immediate savings on the order of $25–$120 million/year are those experienced in the first few years (2023–2025) upon joining with an RTO and arise from: (a) the reduction of associated capacity requirements that can be achieved within a pooled resource adequacy framework due to load diversity; and (b) from the ability to collect revenues from selling any surplus capacity to others at the regional market price. These benefits would be achieved immediately and would persist in a similar magnitude for all years into the future (subject to year-to-year variability).

In addition, South Carolina would be able to achieve future benefits if relying on the regional capacity market to attract future supply investments at a lower price than could be achieved through the IRP model. The scale of these benefits grows over time as the proportion of supply

[148] An illustrative range of low to high PJM capacity prices is used to consider both near-term prices that are relatively low and have already established in PJM's forward auctions, with prices rising to PJM's estimated cost of new entry or cost to build new resources over a timeframe of 2025–2040. See Appendix B for more details.

under regulated cost recovery declines with resource turnover, and the proportion of competitive supply investments increases to fill the capacity need. The greatest benefits will be achieved if many third-party suppliers can identify low-cost incremental supply opportunities that would not have been considered within the Status Quo. If substantial volumes of such opportunities exist, they will be developed even while capacity market prices remain low and customer savings will be greatest. If market-based purchases are only available at higher prices approaching or equal to those available under a utility IRP model, then the benefits of transition to a competitive investment model would be lower. Long-term savings are on the order of $150–$300 million/year for the Incremental Participation scenario and $150–$370 million/year for the Full Participation scenario.

FIGURE 16: INDICATIVE RANGE OF POTENTIAL BENEFITS FOR SOUTH CAROLINA FROM COMPETITIVE INVESTMENT REFORMS (REPORTED IN NOMINAL U.S. DOLLARS)



Sources/Notes: Reported in nominal U.S. dollars.

The scenarios we examine here offer indicative bookends to illustrate the scale of potential benefits, including the high end of benefits from a best practice implementation toward full reliance on a competitive investment model. Other more incremental reforms, such as introduction of competitive procurement to utility IRP, could be expected to achieve a portion of these potential benefits commensurate with the smaller scope and scale of competition achieved. For additional details, see Appendix B.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

If South Carolina determines that the policy of the state is to shift toward a competitive investment model, we recommend that this policy intention could be signaled today but that the implementation should be staged in a measured fashion to mitigate transition risks. The stages of implementation would involve:

- First, joining or creating an RTO market with a requirement that the market include a viable model for attracting competitive capacity supply investments when needed. Even if utility or state-overseen IRPs are used to secure some or most of all supply investments going forward, a viable market-based resource adequacy and investment model would be needed to attract the residual needs.
- Second, if South Carolina were to consider retail access, then establish a coordinated plan and timeframe for the introduction of partial or full retail competition that approximately aligns with the timeframe for transitioning to reliance on competitive supply investments.
- Third, if South Carolina were to consider unbundling and deregulating generation, then for each affected utility, develop a timeline and oversight plan for determining the timeframe and format for (partial) asset divestiture, considering that some assets may be attractive to retain under utility or state ownership for a longer period (e.g., recently-built assets with long outstanding asset lives, large nuclear or hydro facilities with low going-forward cost and high market value). We do not recommend considering transfer of regulated assets to unregulated merchant affiliate companies.
- Fourth, if South Carolina were to consider retail access with a deregulated generation sector, then update rates to separate all segments of the regulated and unregulated business segments, including a distinct line item for the recovery of legacy utility investment costs.

F. Securitization of Costs Related to Retiring Thermal Assets

DESCRIPTION AND RELEVANT CASE STUDIES

Vertically integrated utilities make retirement decisions, under commission oversight, for thermal assets based on a number of economic factors such as going forward costs; fuel and operation costs; capabilities and costs of competing technologies; policy decisions such as environmental regulations and state incentives; as well as the plant age and engineering estimates of remaining useful life. Thermal generation assets owned by a utility can become "impaired" or "stranded" if the plant is no longer expected to provide a net benefit going forward and there remains some undepreciated book value in the rate base that has not yet been recovered from customers. Assets can become impaired or stranded due to changes (or expected changes) in the economic, regulatory, or technological landscape where the utility operates. Many coal assets across the U.S., for example, presently face high going-forward maintenance and operating costs such that they are more costly to continue operating than it would be to retire them and develop or procure replacement supply from lower-cost new gas CC plants, renewables, or market purchases.[149] The public interest is best served by allowing such an impaired coal asset to retire and pursuing cleaner and lower cost replacement resources (even if customers must continue paying down the undepreciated book value after plant retirement). However, not all states have yet formalized processes regarding the regulatory treatment to ensure that impaired assets can be retired when it is economical to do so.

If thermal assets become stranded, there are several options for treating cost recovery of the undepreciated portion of these assets.[150] The first choice before regulators is whether to: (i) allow plants to continue to remain in the rate base and recover their undepreciated book value; (ii) allow utilities to recover undepreciated value outside of the rate base; or (iii) to disallow portions of cost recovery. As shown in Table 14, regulators in various U.S. states have decided to allow retired plants to remain in the rate base as an intangible "regulatory asset" (which may or may not continue to earn the utility's regulated rate of return) or to be allowed to earn the regulated rate of return but over a shorter depreciation schedule.[151] Regulators in some cases

[149] Existing coal generation has been under financial pressure since the shale gas revolution starting in around 2008, exacerbated by increasingly stringent environmental regulations and rapid cost reductions in wind and solar generation. In many cases, the going-forward costs for coal generators has exceeded the annualized costs for replacement generation from new-build alternatives, in which case the efficient solution is to retire the coal plant. Accordingly, between 2012 and 2021, an average of 9,450 MW of U.S. coal-fired capacity was retired each year and 23% of the current coal-fired capacity is planned to retire by the end of 2029.

[150] The term "depreciation" in this context refers to the reduction in the remaining unrecovered capital cost accounted for in the rate base of a regulated utility. This is distinct from the tax depreciation used for calculating taxable income.

[151] Regulatory assets are created when a regulator approves recoverable costs that would increase rates in one period to be implemented at a future time. A regulatory asset is an intangible asset in that the utility has an enforceable present right to increase an amount in the rate base to be charged to customers in future periods. Conversely, a regulatory liability arises when a utility has an enforceable present obligation to deduct an amount in the rate base to be charged to customers in future periods. In the case of early asset retirement, regulators often have allowed the remaining undepreciated value to be recovered as a regulatory asset; see International Financial Reporting Standards Foundation (IFRS) and International Accounting Standards Board (IASB), Regulatory Assets and Regulatory Liabilities, IFRS Standards Exposure Draft ED/2021/1, January 2021; K. Spees and M. O'Loughlin, Stranded Fossil Fuel Infrastructure: How Big Is the Stranded Asset Problem, and What Should We Do About It?, The Brattle Group, June 24, 2021.

have also disallowed cost recovery on portions of the undepreciated asset to the extent that the costs were deemed imprudent. For prudently-incurred costs, utilities and regulators may also examine "securitization" as an alternative financial tool to enable full cost recovery outside of the rate base.[152]

TABLE 14: RECENT EXAMPLES OF REGULATORY TREATMENT OF UNDEPRECIATED THERMAL ASSETS

Treatment	Description	Number of cases (2010-2020)
Rate Based		
Regulatory asset	Plant is retired and utility continues to receive return on and of investment; takes effect upon retirement	20
Accelerated depreciation	Plant's depreciation schedule is changed to match the period until retirement; put in place in anticipation of retirement	7
Not Rate Based		
Securitization	Recovery of stranded assets through ratepayer-backed bonds with low interest rates	3
Partial disallowance	Part of the undepreciated cost or return on that balance is removed	2

Source/Notes: Compiled by Dr. Metin Celebi, The Brattle Group; see K. Spees and M. O'Loughlin, Stranded Fossil Fuel Infrastructure: How Big Is the Stranded Asset Problem, and What Should We Do About It?, The Brattle Group, June 24, 2021.

Securitization is a well-established financial practice employed for a variety of uses in many industries, including several applications for electric utilities. Securitization for thermal generation retirements works by providing strong legal and regulatory assurances for cost recovery of the undepreciated value of a stranded asset in order to enable the utility to issue debt to refinance and recover that value, as depicted in Figure 17. This debt is typically issued as bonds through a Special Purpose Entity (SPE), owned by the parent utility. The bonds are secured by a guarantee (backed by state law and approved by the regulator) that ratepayers will fund repayments through a non-bypassable surcharge on customer bills, which is why they are also sometimes referred to as "ratepayer-backed bonds" or "RBBs." The SPE is considered "bankruptcy-remote" relative to the owning utility, meaning that its financial performance has little economic impact on the parent utility and the debt issued through the ratepayer-backed bonds are nonrecourse to the utility. That is, the issued debt does not draw on the utility's credit

[152] M. Celebi, et al., "Managing Coal Plant Retirements for an Orderly Transition to Decarbonization," The Brattle Group, accessed January 24, 2023.

and should not impact its credit rating.[153] The right to receive payments from the non-bypassable surcharge is sold by the utility to the SPE as an intangible asset, which the SPE then pledges as collateral for the issued bonds. These bonds are then sold to investors. In short, the SPE functions to receive payments from customers through the bill surcharge and to repay the bondholders.

The regulator, in addition to allowing the utility to create the customer bill surcharge to guarantee repayment of the bonds, also guarantees that the SPE will be able to repay bondholders in the future on both principal, interest, and any associated issuance costs by allowing the bill surcharge to be periodically adjusted through a “true-up” mechanism without further regulatory review. These guarantees are enabled and codified by state law. Through these various guarantees, securitization bonds are typically able to obtain an AAA credit rating (the highest rating possible and several grades higher than typical U.S. electric utility credit ratings) and therefore can be issued at very low interest rates.[154] This reduced interest rate minimizes the cost to customers of reimbursing the utility’s unrecovered stranded cost. Furthermore, securitization is a flexible mechanism that can be designed to alleviate sudden increases in rates, known as “rate shocks.”

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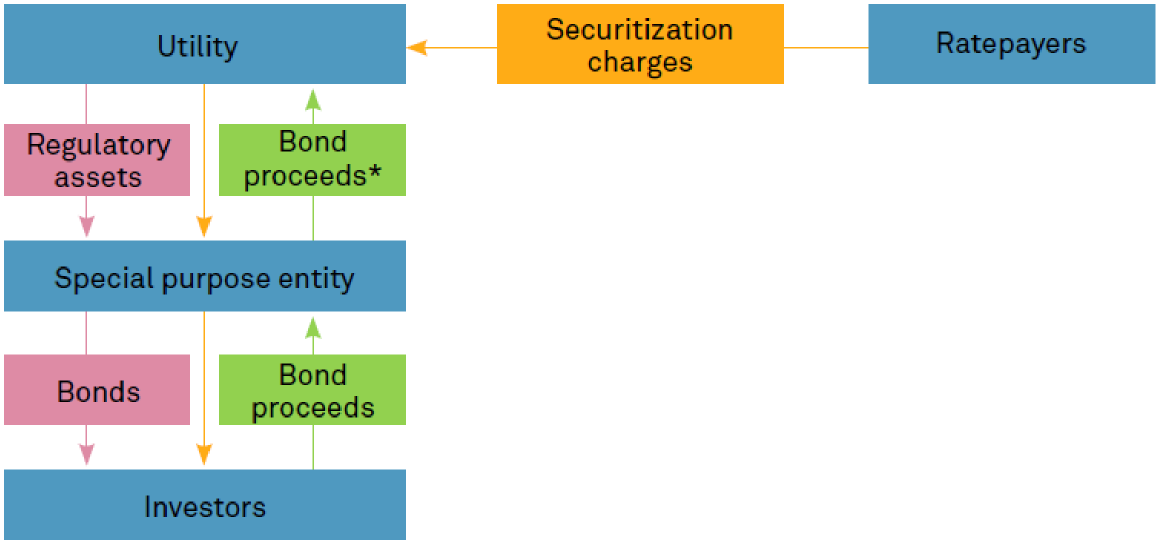
[153] This is true from the perspective of cash flow to the utility although rating agencies are split on the “on-credit” treatment of securitization; See also J.S. Fichera and R. Klein, Lowering Environmental and Capital Costs with Ratepayer-Backed Bonds, Natural Gas & Electricity Journal, Wiley Periodicals, February 2007.

[154] See J.S Fichera, Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update, National Regulatory Research Institute (NRRI) Insights, January, 2019 and Edison Electric Institute (EEI), 2021 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry, Credit Ratings, 2021.

FIGURE 17: SECURITIZATION FLOW DIAGRAM



Sources/Notes: S&P Global Market Intelligence, LLC, "A variety of stranded cost recovery abatement strategies emerging in US energy transition", Regulatory Research Associates Regulatory Focus, Topical Special Report, December 6, 2021.

Through securitization, customers stop paying the utility's cost of capital on the remaining asset, and instead begin paying for the asset through the bill surcharge at the lowest possible interest rate. Securitization also provides tax savings for the utility that can be further passed to customers through rates. When properly designed, securitization can lower customer bills compared to allowing the stranded asset to remain in the rate base and subject to the higher utility return.

Securitization has been implemented in many use cases in the electric sector, and increasingly is being considered in the context of thermal plant retirements. In 2016, Duke Energy Florida was approved to issue $1.3 billion in securitized bonds related to stranded costs from retiring the Crystal River nuclear plant.[155] Compared to full cost recovery at the approved utility rate of return, securitization was estimated to reduce customer costs by approximately $700 million over 20 years.[156] In 2020, the Michigan Public Service Commission approved Consumer Energy Michigan's application for securitization bonds of up to $678 million due to the closure of two coal plants that was estimated to lower the cost of making the utility whole by around $126

[155] U.S. Securities Exchange Commission (SEC), $1,294,290,000 Series A Senior Secured Bonds, Preliminary Prospectus, Dated June 15, 2016, Duke Energy Florida, LLC.

[156] North Carolina Energy Regulatory Process (NERP) Securitization Study Group, Securitization for Generation Asset Retirement, Study Group Work Products, December 18, 2020.

million.[157] Also in 2020, the New Mexico Public Regulation Commission approved securitization bonds of up to $360 million of unrecovered investments due to the abandonment of the San Juan coal plant units 1 and 4.[158] The Public Service Company of New Mexico (PNM) estimated the net bill impact of the securitization and replacement resources would be a savings of $5.93/month per residential customer using an average of 600 kWh per month in 2023, other estimates have quoted approximately $6.67/month in bill savings for an average customer.[159]

Securitization has also been used as a method to recover costs incurred during extenuating circumstances, such as to recover damages from storms and other extreme weather.[160] South Carolina has also enabled securitization for recovery of storm damages.[161] In total, eight states have securitized $6.2 billion in relation to storm damages.[162] Additionally, securitization has been used to fund conservation programs, green investments, environmental compliance measures, company reorganizations, reliability expenditures, impacts from the Covid-19 pandemic, and most notably, costs arising from the transition to enabling retail competition in the 1990's and early 2000's as shown in Figure 18.

[157] Michigan Public Service Commission (MPSC), Press Release, "MPSC OKs securitization bonds for Consumers Energy as utility prepares for 2023 retirement of coal-fired generating units," December 17, 2020.

[158] The Brattle Group, "Unanimous NMPRC Decision for PNM to Abandon San Juan Coal Plant Relies on Expert Testimony by Principal Frank Graves," April 13, 2020.

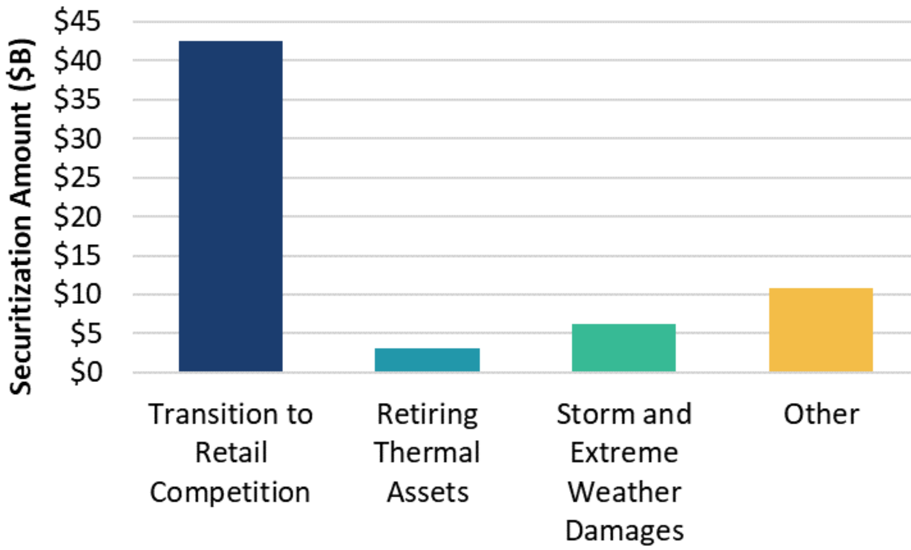
[159] Public Service Company of New Mexico (PNM), Consolidated Application for the Abandonment, Financing and Replacement of the San Juan Generating Station Pursuant to the Energy Transition Act, Before the New Mexico Public Regulation Commission, July 19, 2019; San Juan Citizen's Alliance, "San Juan Generating Station cleared for abandonment by PRC," April 1, 2020.

[160] North Carolina Energy Regulatory Process (NERP) Securitization Study Group, Securitization for Generation Asset Retirement, Study Group Work Products, December 18, 2020.

[161] South Carolina Act No. 227, Effective date June 17, 2022.

[162] These states are: Arkansas, Florida, Kansas, Louisiana, Mississippi, North Carolina, Oklahoma, and Texas; see S&P Global Market Intelligence, LLC, Overview of utility use of securitization in the U.S. by category, Regulatory Research Associates, data gathered as of June 25, 2021.

FIGURE 18: 2021 SECURITIZATION AMOUNTS IN THE U.S. BY USE CASE



Sources/Notes: Nominal U.S. dollars. S&P Global Market Intelligence, LLC, Overview of utility use of securitization in the U.S. by category, Regulatory Research Associates, data gathered as of June 25, 2021.

POTENTIAL ADVANTAGES

The potential advantages of considering securitization as an option for enabling thermal retirements include:

- Can facilitate retirement of stranded thermal assets and enable them to be replaced with lower-cost and cleaner resources.
- Reduces the cost for customers to make the utility whole for prudently-incurred costs.
- Allows utilities to raise new funds for redeployment into newer technology and lowers borrowing costs to enable greater balance sheet flexibility.

POTENTIAL DISADVANTAGES

The potential disadvantages of considering securitization as an option for enabling thermal retirements include:

- Estimates of stranded costs are variable and dependent on assumptions of future conditions; regulators could pre-commit to compensating an amount that exceeds utilities' actual costs with no ability to adjust once decided.
- Since ratepayer-backed bonds are typically exempt from state income tax, some of the cost burden of stranded costs is shifted from ratepayers onto taxpayers.

- Potential to increase borrowing costs for municipalities since securitized bonds (due to their income-tax free status and high credit rating) compete directly with municipal bonds.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

With the passage of Act No. 227 ("Act 227"), South Carolina has existing law allowing for securitization for storm damages recovery. Therefore, existing legislation could be adapted to explicitly enable securitization as one option for regulatory treatment of retiring thermal assets as well. If adopting such legislation, we recommend that it should authorize the PSC to enable plant retirements through securitization when deemed in the public interest. To address any potentially stranded asset costs, the PSC could be authorized to consider all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization. We note that the regulator needs to play an active role to ensure that the interests of ratepayers, taxpayers, utilities, members in the local economy impacted by the plant closure, and potential investors are all balanced to achieve the greatest benefits when considering securitization.

G. Recommendations for Supply Investment Reforms

Based on our assessment of potential supply investment reform options, we recommend that South Carolina policymakers consider the following options. We note that many of these reform options are complementary to each other (not mutually exclusive alternatives). We recommend that South Carolina:

- **Join an RTO that ensures resource adequacy (accounting and enforcement) over a larger, more diverse footprint**. This step would yield immediate cost savings by reducing reserve capacity requirements for South Carolina utilities, by enabling the utilities to more cost-effectively manage temporary surpluses and deficits in their resource plans, and by easing the logistics of major plant retirements. If South Carolina additionally wanted to create the option to transition to a model that is partly or fully reliant on competitive generation investments in the future, we recommend prioritizing consideration of an RTO with a track record of attracting competitive generation investments.
- **Authorize the PSC or other state agencies to consider or conduct statewide IRP processes,** if the PSC identifies a benefit to conducting such an exercise, either to achieve cross-utility coordination benefits, better inform policy choices on a statewide

basis, or provide statewide needs assessments for the purpose of competitive solicitations. The option for an agency-overseen statewide IRP could be utilized either on an ad hoc basis when a specific need is identified, or could be incorporated into regularized IRP processes.

- **Incrementally introduce and expand the role of competitive solicitations within utility and/or state IRP processes**. South Carolina is presently gaining more experience with competitive renewable and all-source solicitations, which (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved via options such as: (a) requiring (rather than "allowing" as is done currently) future supply needs identified in IRPs to be met through all-source competitive solicitations; (b) designing competitive solicitations that will consider utility self-build projects alongside IPP projects, authorizing state agencies to rely on an independent evaluator to conduct the process and recommend winning projects to the PSC for approval; (c) enabling cooperative and municipally owned utilities to participate in state agency or utility-specific procurements, allowing them the option (but not the obligation) to procure a share of selected resources; and (d) (after joining an RTO) considering the option for reliance on regional markets for providing a defined portion of IRP-identified supply needs.
- **Confirm or clarify regulatory policies related to the retirement of uneconomic aging resources** to ensure that utilities have the ability and incentive to retire aging generating assets when other lower-cost supply options become available. In determining the most beneficial outcomes for ratepayers, authorize the PSC to utilize all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization.
- **Consider additional competitive investment reforms in the future.** After gaining experience with RTO market participation, competitive IRP-based procurement processes, and retail market reforms (discussed below), reassess the question of competitive investment reforms to determine whether further transition to competitive investments is desired. If so, consider utilizing a graduated transition path that would rely increasingly on competitive generation investments over time as demand increases, existing resources retire, and existing contracts expire.

IV. Retail Market Reforms

A. Overview of Potential Retail Market Reforms

Currently in South Carolina, vertically integrated utilities are responsible to serve the supply needs of customers within their respective service territories. In the retail sector, this means that utilities own, operate, and maintain the distribution system, administer metering services, ensure procurement or production of power to serve customers, and ensure generated electricity is delivered to customers.

Retail market reforms focus on the question of whether and how customers can choose to procure power from alternative resources or providers of retail electricity as shown in Figure 19. Some resource choice can be achieved by offering advanced retail rate structures, however by enabling customers to select a retailer (a private company that procures power for customers) instead of limiting their supply choice to the incumbent utility), competitive retail markets empower customers to negotiate rates and service offerings through competition among retail suppliers.[163] A competitive retail market would allow customers to better pursue their own preferences with regards to: (i) rate structures (both level and stability); (ii) environmental goals; (iii) supply resource type or locally/community-sourced supply; (vi) communicating billing information and other items with the customer (e.g., traditional mail, app-based, email-based, direct device control); or (v) other innovative types of retail services (e.g., electric vehicle charging or vehicle-to-grid management, demand response programs, bundled electric and gas or other services, distributed solar/battery management, electric and non-electric smart home device management). The retail market reforms we examine in this study include:

- **Utility retail rate reforms to offer additional customer choices** that would authorize or require utilities to design more efficient or advanced retail rates structures.
- Enabling **partial retail choice** for large C&I customers, so that these customers have the ability to seek self-supply or contract with a third-party electricity supplier.

[163] Even if retail competition were introduced, the distribution utility's role in the retail sector as the distribution system planner and owner would continue. The costs of the distribution system would continue to be passed to the retail customer as a non-bypassable charge, even if an alternative retail provider takes over customer billing, customer service, and competes on price/rates relative to all competitively-set line items on the customer bill (that can include energy supply as sourced bilaterally or through RTO markets, investment costs associated with energy supply, and other retail services that may be provided).

- Enabling **full retail choice** including residential and small business customers, to offer the same benefits of competitive retail markets and alternative suppliers to small customers.
- Enabling **Community Choice Aggregation (CCA)** to allow communities (even those not served by a municipally owned utility) to select a third-party supplier of retail electric service.
- **Competitive reforms to enable distributed energy resources,** to create opportunities to incentivize and leverage third-party DR and DER providers.
- Establishing a **third party energy efficiency administrator** to regularize and expand energy efficiency (EE) programs that are cost-beneficial to customers but that have not been fully developed under existing structures.

South Carolina can implement these reforms under state authorities without any cooperation or coordination with other states. While not strictly necessary for most of these reforms, the benefits of retail market reforms are greatly enhanced when paired with a regional wholesale market.

FIGURE 19: POTENTIAL ROLE OF RETAIL MARKET REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo: **Vertically Integrated Utility**	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Retail Market Reforms				**Customer Deliveries** • Customers: Select retail provider to procure needed supply (compete on price, green, or other values)

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

B. Status Quo with Exclusive Utility Service for Retail Supply

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

Under the vertically integrated utility model, retail functions include owning, operating, and maintaining the distribution system, ensuring procurement or production of power to serve customers, providing metering services, and ensuring generated electricity is delivered to customers. Utilities plan for distribution system investments, and the PSC approves distribution system capital investments and operation plans for large utilities, and sets the retail rates large utilities use to recover these investment and operation costs. Retail rates therefore include distribution and retail service costs, which are bundled with generation and transmission costs (as discussed in prior sections). The IOUs in South Carolina (Duke and Dominion) as well as the state-owned utility (Santee Cooper) directly serve customers in their territories but also supply wholesale services to electric cooperatives and municipal utilities, who then serve retail customers.[164]

A central element of the status quo for the retail sector is that the various distribution utilities are granted the exclusive right to provide bundled service to customers within their respective territories. PSC oversight seeks to manage costs and ensure that rates charged to customers by large utilities are set at fair levels in alignment with prudently incurred utility costs. Customers dissatisfied with their rates or other aspects of utility service are not able to seek alternative sources of electricity supply.

ADVANTAGES OF STATUS QUO APPROACH

Advantages of the status quo include:

- Customers enjoy price stability as most investment costs are recovered over a long period
- Retail rates and utility investment choices subject to state oversight

DISADVANTAGES OF STATUS QUO APPROACH

Disadvantages of the status quo include:

- Investment and fuel price risks borne by customers under cost-of-service regulation
- Customers have limited retail service options and are unable to negotiate, switch providers, or pursue self-supply if unsatisfied with service or resource mix

C. Retail Rate Reforms to Offer Additional Customer Choices

DESCRIPTION AND RELEVANT CASE STUDIES

A wide array of innovative rate structures have been, and can be, used to increasingly improve the customer choices and value of electric service (even if other retail reform options are not implemented). We review here a subset of potential rate design reforms that generally seek to offer more economically efficient rates, activate demand response and DERs to provide grid services, enable more opportunities to select green supply, and improve utilities' incentives to

[164] For example, Central Electric Cooperative is a customer of Santee Cooper and Duke, and supplies its 20-member cooperatives with wholesale services. The individual member cooperatives then directly serve customers.

reduce costs. Some of these rate options are already under consideration or in use within South Carolina (we do not attempt to compare all South Carolina utilities' rates relative to these options for the purposes of this study.)[165]

Cost-causation is a fundamental principle underlying economically efficient and effective rate design, meaning that electricity pricing should reflect the economic cost of providing electricity to customers.[166] Cost-based rates should lead to improvements in equity and fairness in cost recovery by removing unintended subsidies embedded in the rate design. When designed well, cost-based retail rates contribute to reduced distribution costs in the long run by encouraging customers to use electricity more efficiently.[167]

Time-varying rates are a category of rates that seek to provide economically efficient price signals to customers, demand response providers, and DERs to behave and operate in ways that improve the overall cost effectiveness of the system and reduce total system costs. Customers and distributed resources reacting to such rates can change their consumption profiles or net production profiles in ways that reduce total system costs, as long as their retail rate offers an accurate incentive to do so. Several categories of time-varying rates include:

- **Time-of-use (TOU)** rates charge customers a higher price during an established peak period and a lower price during one or more off-peak periods.[168] While traditional TOU rates have been offered for decades, TOU rate design recently has experienced renewed interest as an element of net energy metering (NEM) reform, as well as a tool for encouraging off-peak charging of electric vehicles (EVs) or for incentivizing load shifting to hours with excess solar output. For example, some utilities and state regulators have begun to deploy TOU rates as the default rate option for residential customers.[169]
- **Critical peak pricing (CPP)** is a form of dynamic pricing, with a peak period price that can be implemented selectively on days with significant capacity constraints. CPP events can be called to reflect capacity constraints at the bulk system level, or to manage local distribution

[165] Many new retail rate structures have been enabled in the South Carolina Energy Freedom Act which has provisions for Net-Energy Metering, access to residential and community solar, "solar choice" TOU rates, among others. South Carolina Act No. 62, "SC Energy Freedom Act," effective date May 16, 2019.

[166] A. Faruqui, et al., Modernizing Distribution Rate Design, The Brattle Group, prepared for ATCO, March 13, 2020.

[167] A. Faruqui, et al., Modernizing Distribution Rate Design, The Brattle Group, prepared for ATCO, March 13, 2020.

[168] A. Faruqui, et al., A Survey of Residential Time-Of-Use (TOU) Rates, The Brattle Group, November 12, 2019.

[169] A. Faruqui and R. Hledik, Smart by Default, The Brattle Group, Fortnightly Magazine, August 2014.

system constraints.[170] Thus far, CPP rates largely have been implemented through participation-limited pilots, through interest in deploying them on a full-scale basis to encourage load flexibility is growing in some jurisdictions.[171]

- **Peak time rebates (PTR)** are similar to CPP rates in the sense that they include an event-based demand signal. However, unlike CPP, PTR provides customers with the incentive to reduce peak usage through a rebate payment for all kilowatt-hours of usage reduced below an estimate of their baseline usage during the event. Generally, utilities and regulators have been more willing to deploy PTR to customers on a default basis than CPP because PTR is a no-lose proposition for participants; meaning there is no risk that their bill will increase as a result of enrolling. However, a challenge of PTR implementation is estimating the customer's baseline usage and the risk of free-ridership.
- **Residential capacity/demand based retail rates** bill customers for their maximum demand over a billing cycle, often as measured over all hours of the cycle but sometimes only measured during hours of a peak coincident window (e.g., 2 pm to 6 pm).[172] While demand charges have been a common rate design feature for larger customers, they are much less common for residential customers. However, demand charges have recently emerged as an option for improving recovery of fixed costs from residential customers without the potentially regressive impacts of significantly increasing fixed charges.[173]

Green tariffs and green pricing programs have been implemented in states with vertically integrated utility models, where customer options for accessing renewable resources are expanding through "green tariff" and/or "green pricing" programs.[174] Green Tariffs/Pricing programs have emerged recently as an option offered by utilities to enable customers to procure up to 100% of their electricity from clean sources at a fixed or predictable price. With green tariffs, customers pay a premium to ensure that some or all of their electricity consumption is covered by carbon-free generation. That clean energy can come in the form of Renewable Energy Credit

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[170] A. Faruqui and R. Hledik, Time-Varying and Dynamic Rate Design, The Brattle Group, Regulatory Assistance Project, Global Power Best Practice Series, July 2012.

[171] A. Faruqui and S. Sergici, Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity, The Brattle Group, published in The Electricity Journal, Volume 30, Issue 10, December 2017, pp. 64–72.

[172] R. Hledik, Rediscovering Residential Demand Charges, published in The Electricity Journal, Volume 27, Issue 7, September 2014, pp. 82–96

[173] R. Hledik and A. Faruqui, Competing Perspectives on Demand Charges, The Brattle Group, published in Public Utilities Fortnightly, September 2016.

[174] National Renewable Energy Laboratory (NREL), Status and Trends in the Voluntary Market (2020 data), September 29, 2021.

(REC) purchases or funding a new utility renewables project, for example. In practice there are three kinds of Green Tariffs that have developed: Sleeved PPAs, Subscription Programs, and Market-based Rates (MBR).[175]

- **Sleeved PPAs** are so called because the customer negotiates with the utility to dedicate a new or existing renewable energy facility to meet all or a significant portion of the customer's load. The utility acts as an intermediary on behalf of the interested customer and signs a PPA with a renewable developer. The PPA is then "sleeved" through the utility to give customers access to the clean energy procured with the PPA, and customers are charged for the costs of the renewable power and development charges over and above the base utility rate. Contract length minimums are usually longer (two years or more) since the customer contracts a dedicated renewable resource for their consumption and typically has an input to project location and technology type.
- **Subscription programs** are another way customers can access clean energy. In this approach the utility either signs a PPA with a renewable developer or develops and owns the renewable project. The main difference is now the utility either works with the renewable developer or fully determines the resource type and location. The customer pays a fixed price for renewable energy and retail service, and also gets credited for any excess supply the renewable resource generates. Contract lengths are typically shorter and sold in MW blocks. Subscription pricing has also been implemented to contribute to a variety of environmental and policy goals, such as energy efficiency, demand response, or clean energy subscriptions.[176]
- **Market-based rates** work by having the utility allow customers to contract with a renewable developer within an ISO or RTO territory. The customer is then charged a fixed price for renewable energy based on the market rate and (if the customer has onsite DERs) can sell energy and RECs into the market. Contract lengths are typically one year or longer.

Green Tariffs have seen some success in attracting corporate buyers of clean energy. In 2016, Facebook announced its decision to open a new data center in New Mexico. This decision was made in part because the Public Service Company of New Mexico (PNM) created the state's first green tariff program to enable Facebook to supply 100% of its energy needs from renewable

[175] S. Sergici, Accelerating the Renewable Energy Transformation, The Brattle Group, presented to the EUCI Southeast Clean Power Summit, February 25, 2019.

[176] P. Fox Penner et al., FixedBill+ Making Rate Design Innovation Work for Consumers, Electricity Providers, and the Environment, The Brattle Group and Energy Impact Partners (EIP), Working Paper, June 2020.

generation.[177] The data center has since garnered capital investment of over $2.2 billion in the state.[178] In South Carolina, Duke Energy has recently had the Green Source Advantage program approved by the PSC, which consists of a total capacity of 200 MW of new renewable energy available to large customers.[179] Similarly, Dominion has proposed a Voluntary Renewable Energy Rider program for 135 MW for large customers.[180]

POTENTIAL ADVANTAGES

The potential advantages of pursuing options for new retail services and rate designs depend on the type of rate reforms in question and the underlying improvement they seek to achieve. Benefits generally include:

- Improved economic efficiency, with more efficient price signals embedded in the retail rate structure in line with economic principles of cost causation.
- Time-varying rates can provide customers with better incentives against which to manage consumption levels, consumption profiles, and activate DR/DER assets. Customers taking advantage of such rates can reduce their own bills at the same time as producing system-wide cost savings.
- Green tariffs and similar options can provide customers with opportunities to access clean energy resources in alignment with their own environmental and sustainability goals.

POTENTIAL DISADVANTAGES

Pursuing alternative retail services and rate design options has minimal disadvantages, as long as the new rates are reviewed and implemented with sufficient care to ensure that they enhance economic efficiency, improve customer choice, and follow the key principle of cost causation.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Many of these potential advances in rate design may already be possible to pursue under existing law (and some are already in use by several utilities). If South Carolina wished to expand the use

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[177] Sanem Sergici, Accelerating the Renewable Energy Transformation, The Brattle Group, presented to the EUCI Southeast Clean Power Summit, February 25, 2019.

[178] The Tech Capital, "Meta raises Facebook Los Lunas data centre investment to $2.2bn," November 1, 2022, accessed February 2, 2023.

[179] Duke Energy, "Green Source Advantage offers more renewable energy options for South Carolina customers," February 23, 2021

[180] Dominion Energy South Carolina, Inc., Rider to Retail Rates: Voluntary Renewable Energy ("VRE") Rider for Renewable Generation ("RG") Supply Agreements, July 26, 2021.

of potentially beneficial rate-making options, the legislature could explicitly authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices for South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, expanding green tariffs and related green energy options, and rate designs to enhance efficiency.

D. Partial or Full Retail Choice

DESCRIPTION AND RELEVANT CASE STUDIES

From the mid-1990s through the early 2000s, several states restructured their electric markets to allow for retail choice. "Retail choice" refers to enabling consumers to procure their electricity from a variety of competitive retailers that provide their customers with electricity service by purchasing electricity from the wholesale RTO market, through self-supply, or through bilateral contracts. While retailers purchase power on behalf of their customers, they deliver the power across transmission and distribution lines that continue to be owned and operated by the incumbent utility. Customers that do not choose to receive service from a third-party supplier will continue to be served under a rate-regulated option that may or may not be provided by the incumbent utility.

States that have implemented retail choice can be classified as either full or partial retail choice depending on whether the ability to procure electricity from competitive suppliers is limited to certain customer types (typically large C&I consumers) or enabled for all customers (including small businesses and residential consumers). Nearly all retail choice programs are voluntary and function on an opt-in basis. Customers under opt-in retail choice that do not choose to participate in the retail market are assigned a designated default service, sometimes called Standard Offer Service, Basic Generation Service, Provider of Last Resort (POLR), Price to Beat, or PUC Offer.[181] Standard offer service rates are developed under commission oversight for IOUs, and reflect a regulator-approved method for developing retail rates as a function of wholesale electricity prices, including utilizing a level of price hedging deemed appropriate by the regulator. A typical approach is to auction off the right to provide standard offer service in 2–3 year intervals, auctioning a slice-of-system in each auction and relative to the realized profile of the aggregate pool of customers being served. Potential providers of the retail service compete to offer the price hedge at the lowest cost (considering their own assessment of wholesale market risks and their own ability to self-supply or contract).

[181] F. Graves, et al., Retail Choice: Ripe for Reform?, The Brattle Group, July 2018.

A wholesale market (such as an RTO) is a highly valuable (though not strictly required) precondition for introducing effective retail choice. A wholesale market allows for a much clearer energy price signal and price to beat, enabling clarity in the unbundling of generation services from transmission/distribution services to enable product differentiation and extract meaningful benefits for retail customers.

Currently, 18 states and the District of Columbia have active, statewide residential retail choice programs (see Figure 20 below). Five of the 18 states—Georgia, Virginia, Michigan, California, and Oregon—have partial retail choice that is mostly available to large C&I customers in certain jurisdictions within the state. Typically, retail choice (and the subsequent retail markets) form in states that already have wholesale markets; however, there are notable exceptions such as Georgia, which has enabled partial retail choice for large C&I customers but is not part of an RTO. Of the states that have retail choice, between 10%–50% of residential and 65%–90% of C&I total eligible load exercised their right to switch to competitive retail providers in 2018.[182] Outside of Texas, Ohio has the highest number of residential retail choice customers, followed by Illinois and Massachusetts. In recent years, Massachusetts has seen steady growth in retail choice participation, while conditions in Ohio have caused participation to level off and in Illinois to decline.[183]

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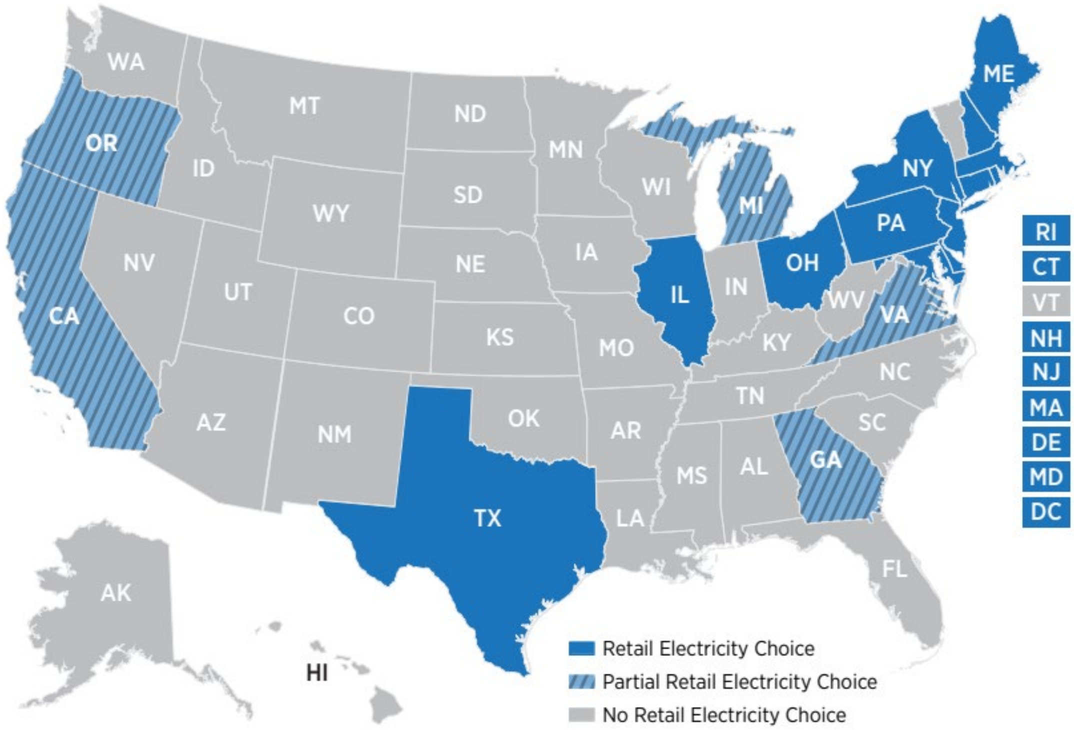
[182] S. Sergici, Status of Restructuring: Wholesale and Retail Markets, The Brattle Group, presented to the National Conference of State Legislatures, June 26, 2018.

[183] U.S. Energy Information Administration (EIA), Today in Energy: Electricity residential retail choice participation has declined since 2014 peak, November 8, 2018.

FIGURE 20: STATES WITH RETAIL ELECTRICITY CHOICE



Source/Notes: National Renewable Energy Laboratory (NREL), An Introduction to Retail Electricity Choice in the United States, August 2017, Figure 1.

The goals of restructuring for retail choice are to reduce average retail prices, enable greater access to renewable energy, integrate more flexible resources, and increase penetration of price-responsive demand.[184] Evidence from implementation of retail choice in other states has shown that in some places retail suppliers are innovating by bundling other services and products with electricity supply. Some innovations that have developed in retail markets are: (i) offering other eco-conscious products to green customers (100% renewable supply rates, energy audits, home protection, carbon offsets, demand response programs); (ii) non-traditional price structures (price risk management, flat monthly billing, free night usage, and various promotions and discounts); and (iii) bundled services (electricity plus gas service, home automation and security,

[184] See F. Graves, et al. Retail Choice: Ripe for Reform?, The Brattle Group, July 2018; T.L. Hogan, "Texas Electricity Prices Are Lower Due to Deregulation," American Institute for Economic Research (AIER), March 2, 2021; Grid Strategies, LLC, Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment, prepared for Wind Solar Alliance, March 2020; University of Texas Austin Energy Institute, The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, July 2021, p. 89; P.R. Hartley, et al., Electricity reform and retail pricing in Texas, Journal of Energy Economics, Volume 80, 2019, pp. 1–11.

energy plus internet services).[185] The greatest and most widely-agreed-on benefits of retail choice are associated with larger customer classes, who tend to be sophisticated power consumers that typically exercise their right to switch providers at high rates, are able to optimize their own consumption, participate fully in wholesale markets (e.g., as DR resources), shop around for retailers or full-service energy service providers, and engage in green power purchase agreements.[186]

The benefits of retail competition have lagged and been less clear for mass-market (residential and small businesses) consumers, who tend to have lower switching rates in most states. In some cases, the explanation of lower switching rates is that retail electricity markets are too confusing, have high switching costs, or that alternative suppliers cannot offer sufficiently lower rates to make a change worthwhile.[187] In other cases, the retail markets are not sufficiently open to enable meaningful retail rate competition and impose excess barriers to entry to alternative suppliers (e.g., lack of real-time access to smart meter data, lack of ability for third party providers to take over billing functions).

Texas is unique in that it enables full retail choice for all customers who must either choose a competitive supplier or they will be assigned one.[188] While Texas does have a Provider of Last Resort (POLR), it is expensive relative to competitive retailers and generally encourages participation in the retail market. Texas regulators have taken a relatively “light touch” to regulating retail markets, allowing competitive retailers to set rates in ways that match their own costs and attract interest from customers. For these reasons, switching rates are higher in Texas than other states with retail choice, with some competitive retailers offering a variety of innovative rate offerings and deals to attract customers.

Texas retail market also is served under a competitive wholesale market model served by the Electric Reliability Council of Texas (ERCOT), which is a single-state RTO and is the only RTO in the U.S. that is not interconnected with its neighboring regions. Unlike the other U.S. RTO/EIM markets, Texas does not have a capacity market or capacity mechanism and is set up to produce

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185 F. Graves, et al. Retail Choice: Ripe for Reform?, The Brattle Group, July 2018.

186 A.J. Ros, An Econometric Assessment of Electricity Demand in the United States Using Utility-specific Panel Data and the Impact of Retail Competition on Prices, Energy Journal, 2017, Volume 38, pp. 73–99.

187 J. Kahn-Lang, Competing for (In)attention: Price Discrimination in Residential Electricity Markets, University of California Berkeley, Haas Energy Institute, November 28, 2022; M.J. Morey and L.D. Kirsch, Retail Choice in Electricity: What have we learned in 20 years?, Christensen Associates Energy Consulting LLC, prepared for Electric Markets Research Foundation, February 11, 2016;

188 This applies to the majority of the state that is within the ERCOT territory.

higher levels of energy price volatility, a key element of an "energy-only" market design. The implication of this higher wholesale market price volatility (combined with relatively few hedging controls or a traditional standard offer service in the retail market) is that high market price volatility can be passed directly to customers.

Typically, Texas competitive retail rates have been very low compared to national averages and customers have enjoyed low rates, but extreme events occasionally occur (most notably the extreme high prices that occurred during Winter Storm Uri).[189] Competitive retailers that were not sufficiently hedged against these events ended up passing the extreme wholesale prices onto customers. Households that experienced these price spikes were all on wholesale-indexed plans that tied their retail rates directly to wholesale prices. When wholesale gas and electricity prices spiked due to the natural gas scarcity and emergency conditions, the prices of these indexed plans followed suit. Later analysis has shown that these affected customers represented less than 1% of retail customers in ERCOT (since the majority of retail customers in Texas have fixed-rate retail plans) and many of these customers ultimately will not be liable for paying these bills due to subsequent consumer protection efforts.[190]

POTENTIAL ADVANTAGES

The potential advantages of pursuing partial or full retail choice include:

- Retail choice increases the transparency of costs and prices.

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[189] The ERCOT territory in Texas experienced more disruption from Winter Storm Uri than neighboring states in SPP and MISO since it is electrically isolated from its neighbors, which meant ERCOT operators were unable to draw power from other regions in the U.S. that were not experiencing extreme cold conditions at the same time. Furthermore, the areas of Texas that are outside of ERCOT territory fared considerably better during the storm, demonstrating the benefits of greater interconnection. The Energy Institute at The University of Texas Austin and FERC/NERC report the main causes of the severity of Winter Storm Uri were due to the lack of winterization of gas plants, which caused reduced gas production, and not due to the market structure. ERCOT ultimately had to shed 20,000 MW of firm load at the worst point of the event compared to SPP and MISO operators, which had to shed a combined total of 3,418 MW of firm load at their respective worst points, despite facing similar levels of plant outages due to the extreme cold conditions. See Federal Energy Regulatory Commission (FERC) and North American Reliability Corporation (NERC), FERC–NERC Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States, November, 16, 2021; University of Texas Austin Energy Institute, The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, July 2021; and Texas Monthly, "El Paso Heeded the Warnings and Avoided a Winter Catastrophe," February 19, 2021.

[190] G. Sharfman and J. Merola, Beyond Texas Evaluating Customer Exposure to Energy Price Spikes: A Case Study of Winter Storm Uri, Interlometry, October 2021, pp. 24 and 25; Office of the Attorney General of Texas, Press Release "AG Paxton Ensures Forgiveness of $29 Million in Electric Bills for 24,000 Texans After Suing Griddy Energy, LLC," March 16, 2021.

- Retail markets are more efficient at passing through cost savings from wholesale markets to end consumers, which can lower average bills by incentivizing customers to manage their own consumption more efficiently.
- Retail competition is attractive for large C&I consumers, municipalities/coops, and communities to lower bills and accelerate energy policy goals.
- Opportunities are created for third-party DR/DER providers and aggregators to identify innovative products and services.
- State could be a more attractive location for future businesses, particularly large C&I customers that would take full advantage of available supply opportunities.

POTENTIAL DISADVANTAGES

The potential disadvantages of pursuing retail choice are mostly related to offering retail choice for small customers and include:

- Retail products can be confusing to small, less sophisticated buyers of electricity, potentially exposing them to higher market volatility and risk than under regulated rates.
- Difficult to fully facilitate competition in the residential and small business sector or extract benefits without also moving toward a competitive investment model in a coordinated fashion for the same customer classes.
- Additional regulation needed to protect residential consumers against excess price volatility, unfair or deceptive marketing practices, and ensure transparent communication of product offerings.
- Both partial and full retail access require mechanisms to equitably address legacy investment costs and avoid cost shifting.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Legislation would likely be required to enable retail choice but can be implemented without any coordination from neighboring regions. Retail choice could be rolled out in a staged fashion, beginning with first offering partial retail choice to large customers where the benefits are greatest. Rates can then be unbundled across different components of the bill, increasing the transparency of costs relative to rates available on the wholesale market. Once sufficient experience is gained with partial retail choice, South Carolina can assess experience to date and determine whether full retail restructuring is desired.

Participation in an RTO will greatly increase the ability to effectively implement any level of retail choice; particularly one that offers a sufficient structure for ensuring resource adequacy and reliability on behalf of switching customers. As discussed above (under competitive investment reforms), the introduction of any level of retail choice should be done in coordination with generation planning and investment reforms so that legacy investment costs can be recovered in an equitable fashion. This may mean that a "transition charge" or "exit fee" would be assessed to relevant customer classes over a relevant transition period.

E. Community Choice Aggregation

DESCRIPTION AND RELEVANT CASE STUDIES

Community Choice Aggregation (CCA) programs enable local governments (cities and municipalities) to procure power on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving transmission and distribution service and consolidated billing from their existing utility provider. By forming a CCA, local governments assume control of procuring energy and capacity, while utilities maintain ownership over the transmission and distribution systems. By aggregating demand, participants in a CCA can gain leverage to negotiate better electricity rates with competitive suppliers and exert more control over the types of generation resources that that supplies their electricity.

While most CCAs emphasize reducing the cost of electricity, some also focus on: (i) supplying their customers demand through "green electricity" by procuring supply from renewable energy sources oftentimes through Power Purchase Agreements (PPAs); (ii) reducing greenhouse gas emissions; (iii) establishing new revenue streams to support local energy programs; and/or (iv) creating local jobs. Most CCAs seek to accomplish several of these goals simultaneously. Almost all CCAs offer equal or lower prices than the incumbent supplier with some offering savings as high as 15–20 percent.[191] In recent years, CCAs have also been able to take advantage of the decreasing costs of renewables to offer lower rates. Since most utilities procure renewable energy using long-term contracts and in some cases may have locked in their rates when renewables were more expensive, CCAs may sometimes be able to negotiate with newer, cheaper renewable energy providers.

[191] E. O'Shaughnessy, et al., Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets, NREL, February 2019; Lean Energy, What is a CCA?, accessed January 11, 2023.

CCAs are currently authorized in 10 states including: Massachusetts (since 1997), Ohio (since 1999), Virginia (since 1999), California (since 2002), Rhode Island (since 2002), New Jersey (since 2003), Illinois (since 2009), New York (since 2014), New Hampshire (since 2019), and Maryland (since 2021).[192] The majority of these states (8 out of 10) follow the "opt-out" structure so that the CCA becomes the default electricity provider and customers must opt out in order to return to using an alternative competitive retail provider or standard offer service. The opt-out structure greatly increases program participation relative to a voluntary "opt in" structure, which requires consumers wanting to participate to complete an additional step. In 2020, approximately 4.7 million customers nationwide procured about 13 million MWh of voluntary green power through CCAs with the majority of these customers being in California (3.9 million customers).[193]

In cases where CCAs are enabled in regions with vertically integrated utility investment models, CCA legislation typically include provisions to prevent shifting legacy utility investment costs onto the customers that are not a part of the CCA and remain with the utility service. One common approach is to require CCAs to pay "exit-fees" to the existing utility to help cover a share of legacy investment costs, similar to those discussed above in the context of competitive retail supply.[194] In California this is implemented through the Power Charge Indifference Adjustment (PCIA), a charge that aims to ensure that both utility customers and those who have left the utility to join a CCA pay for the above market costs for electric generation resources that were procured by the utility on their behalf. "Above market" refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Along with the costs, the CCA receives its residual share of capacity credit and renewable energy credits over the transition period.

POTENTIAL ADVANTAGES

The potential advantages of community choice aggregation include:

- More control for communities to negotiate and lower their energy rates.
- Enables communities to more rapidly achieve green energy policy goals.

[192] United States Environmental Protection Agency (EPA), Community Choice Aggregation, Last Updated on November 21, 2022.

[193] National Renewable Energy Laboratory (NREL), Status and Trends in the Voluntary Market (2020 data), September 29, 2021, slide 19.

[194] Absent an exit fee or similar structure, the introduction of CCAs could risk inequitable cost shifting. By losing customers to the CCA, the incumbent utility must bear the costs of legacy investments, but now must do so over a smaller customer base. This dynamic drives a cross subsidy where the rates for the remaining utility customers rise as fewer customers must still cover past investments, while the CCA customers are able to reap the benefits of lower prices by procuring their supply from lower cost resources.

- Can spur local job creation, clean energy innovation, and investment for CCAs that opt to align these local goals with their power supply purchase agreements.

POTENTIAL DISADVANTAGES

The potential disadvantages of community choice aggregation include:

- Need to equitably address legacy investment costs and avoid cost shifting.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Similar to the introduction of partial or full retail choice, the ability to effectively implement CCAs would be greatly enhanced by participation in a regional RTO or EIM market, particularly one with an effective mechanism for ensuring reliability and resource adequacy on behalf of CCAs and switching customers.

To enable Community Choice Aggregation, the South Carolina legislature would have to enact a law allowing for CCAs to form, designate which entities (counties, cities, towns, villages, etc.) could form a CCA, and would need to distinguish within that enabling legislation whether the opt-out or opt-in approach would be taken, among other provisions.[195] Additionally, the PSC would have to act to create a cost-recovery mechanism to be imposed on any CCA to prevent a shifting of costs onto the remaining customers of incumbent utilities.

F. Competitive Reforms to Enable Distributed Energy Resources

DESCRIPTION AND RELEVANT CASE STUDIES

The emergence of distributed energy technologies, electrified transport, smart homes, and behind-the-meter storage and generation will change the way customers interact with the distribution system. New consumer types, sometimes called "prosumers" not only draw power from the grid but can additionally provide generation to the grid, imparting a new bi-directional usage of the distribution system. Distributed Energy Resources (DERs) are small electricity resources that are distributed throughout the distribution system that may be uncontrollable or

[195] For a list of all CCA-enabling state legislation see Lean Energy, "CCA by State," accessed January 11, 2023.

controlled by DER aggregator companies.[196] The growing DER environment is distinct from the traditional approach of large power plants operated in a centralized fashion with unidirectional power flow. Examples of DERs can include resources such as Demand Response (DR) which can be customer or device curtailments; electric vehicles that can be controlled to charge at preferred times (or even discharge into the grid); heating ventilating and air conditioning (HVAC) building control devices; distributed behind-the-meter battery storage; or distributed rooftop solar. The number, variety, and quantity of DERs is rapidly increasing, as well as the available technologies and companies seeking to capture these resources' potential to offer valuable services to end use customers and the grid as a whole.

The distribution system consists of medium-voltage lines (usually on wooden poles) designed to carry several megawatts (up to tens of megawatts) of power from the high-voltage transmission grid to end users in homes and businesses. The transmission system, by contrast, uses tall (usually steel) pylons to move many hundreds or thousands of megawatts across an interstate grid. As generation technologies have become more modular, and as control and communications have dramatically decreased in cost, the opportunities to connect smaller DERs to consumer facilities (or directly to the utility distribution system) have expanded. At the same time, the distribution system, and the ability of DERs to support it, is of growing interest for several reasons:

- The growth of electric vehicles (and, in some states, electric heat) increases the strain on the distribution system;
- Net metering policies promote growing deployment of rooftop and small solar installations at customer facilities; and
- Greater reliance on electricity yields growing interest in microgrids and other technologies that can provide backup power and improve grid resilience.

DERs, when operated against the right incentive structure, offer a significant opportunity to efficiently and cost effectively meet customer preferences while lowering system costs. On the other hand, DERs facing an ineffective incentive structure (for example, one designed for inelastic customers) can introduce challenges to the system such as by increasing net load uncertainties.

[196] In the RTO environment, the participation of DER in wholesale markets (through an aggregator) has been mediated through FERC Order 2222, which sets minimum standards for reasonable access to wholesale markets by DER. Most of the high-level Order 2222 tariff rules for the RTOs have already been filed, and are planned for implementation later this decade or early in the next. These involve various software changes at the RTO level. The distribution utilities are making complementary plans to interface with the RTO to take a role in the dispatch of DER aggregations and to secure visibility into aggregate DER output and schedules. See Federal Energy Regulatory Commission, [172 FERC ¶ 61,247, Docket No. Rm18-9-000, Order No. 2222](), issued September 17, 2020.

For example, distributed (solar) generation, storage, and EV resources that can be aggregated to be controllable will not be activated to operate the most beneficial way for the grid if there are no incentives to do so. The opportunities to better activate such resources include creating enhanced utility rates (as discussed above), joining RTO markets and enabling DERs to fully participate in providing RTO-defined system services such as capacity and ancillary services, opening retail markets sufficiently to enable DERs to operate with unique and innovative retail structures, and enabling DERs to offer their supply into all-source procurements. South Carolina has also taken through the Energy Freedom Act

Because they can provide benefits to consumers, to the utility's local distribution system, as well as to the bulk grid, the upfront costs of DERs can be more than offset by the combination of such benefits. For example, some customer-sited batteries in RTO territories reach a net profit by combining several stacked services such as capacity and frequency regulation sold to the RTO, while providing emergency backup service and customer bill management through peak shaving to the end user.[197] Similar concepts are being applied to solar projects, solar-battery hybrids, gas engines, controlled electric vehicle charging, thermostat aggregations, and other DERs.

Retailers, regulators, and utilities are rapidly exploring options for encouraging electric vehicle (EV) adoption and incentivizing efficient charging such as encouraging overnight EV charging.[198] Many rate designs are EV-specific TOU rates that are being offered as an option for home charging.[199] Utilities and competitive retailers also have experimented with a variety of ways to temporarily limit the impacts of existing rate designs on developers of high-speed public charging stations, to allow that industry to continue to develop as the EV market matures.[200] Methods to encourage electric heating adoption are also gaining traction. While some utilities and retailers have offered discounts for customers with electric heating for decades (through seasonal declining block rates or a reduced average rates) designs that minimize bills for customers with heat pumps while still remaining consistent with the overall rate design principle of cost-

[197] U.S Energy Information Agency (EIA), Battery Storage in the United States: An Update on Market Trends, August 2021.

[198] R. Hledik, et al., Residential Electric Vehicle Time-Varying Rates That Work: Attributes That Increase Enrollment, prepared for the Smart Electric Power Alliance (SEPA), November 2019.

[199] Direct Testimony of Sanem I. Sergici on behalf of New Hampshire Department of Energy, in the matter of: Public Service Company of New Hampshire D/B/A Eversource Energy, Electric Vehicle Make-ready and Demand Charge Alternative Proposals, Docket no. DE 21-078, February 25, 2022.

[200] R. Hledik and J. Weiss, Increasing Electric Vehicle Fast Charging Deployment: Electricity Rate Design and Site Host Options, The Brattle Group, prepared for Edison Electric Institute, January 2019.

causation are increasingly being considered.[201] Load flexibility is being encouraged by retailers and utilities by offering increasingly sophisticated tariffs for large customers with flexible loads.[202] In some cases, these approaches are developed as a tailored offer for a single very large customer. Examples of such customers include data mining, pulp mills, electric vehicle fleets, and customers with large backup generators or behind-the-meter batteries.[203] In addition to rate designs, customers can be provided with tariff-based incentives to participate in demand response and load flexibility programs.[204] Payments to service provides for these programs often come in the form of rebates, bill credits, or rate discounts. Such programs are quickly evolving from conventional "peak clipping" programs to advanced load flexibility programs that provide a broader range of services to the grid (e.g., daily load shifting, ancillary services, geo-targeted demand reductions).[205]

DERs can be activated effectively through access to wholesale RTO markets (directly for large customers, or indirectly through retailers and aggregators for smaller customers). In RTOs, more services are available as market based products, which can be provided by any supplier (supply or demand side) that have the technical capabilities to do so. For example, market operators are exploring ways to enable electric vehicles to provide grid services, which has given rise to the Vehicle-to-Grid (V2G), or the more general Vehicle-to-Everything (V2X), concepts.[206] Access to these markets are often used to support DER business cases, in some cases making up half or more of the overall value of DER deployment.[207] Examples of such markets include ancillary services like frequency regulation and spinning reserves, the wholesale energy market featuring real-time prices, and capacity markets to signal the regional value of adding peak supply or

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[201] S. Sergici, et al., Heat Pump-Friendly Cost-Based Rate Designs, The Brattle Group, prepared for Energy Systems Integration Group (ESIG), January 2023.

[202] R. Hledik, et al., Distribution System Pricing with Distributed Energy Resources, prepared for Lawrence Berkeley National Laboratory (LBNL), May 2016.

[203] A. Faruqui and R. Hledik, An Assessment of Nova Scotia Power's Proposed Extra Large Industrial Active Demand Control Tariff, September 26, 2019

[204] The Brattle Group, A National Roadmap for Grid-Interactive Efficient Buildings, prepared with Lawrence Berkeley National Laboratory for the United States Department of Energy, May 17, 2021.

[205] R. Hledik, et al., The National Potential for Load Flexibility: Value and Market Potential Through 2030, The Brattle Group, June 2019.

[206] A.W. Thompson and Y. Perez, Vehicle-to-Everything (V2X) energy services, value streams, and regulatory policy implications, Energy Policy, Volume 137, February 4, 2020.

[207] See Hledik, et al., Stacked Benefits: Comprehensively Valuing Battery Storage in California, The Brattle Group, Prepared for Eos Energy Storage, September 2017; Fitzgerald, et al., The Economics Of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver The Most Services And Value To Customers And The Grid, Rocky Mountain Institute, September 2015; Value Stacking in Minster: A Rural Village Leverages Solar, Storage and 4 Revenue Streams, Smart Electric Power Alliance, November 2016.

removing peak demand. Other grid resiliency products such as black-start capabilities and emergency back-up generation exist and new services are also developing to benefit distribution systems, such as distribution build-out deferral, local capacity, reactive power support, and voltage regulation, though markets for these services are in the nascent stages of development and are typically settled by out-of-market mechanisms.[208]

POTENTIAL ADVANTAGES OF REFORMS TO ENABLE DERS

Potential disadvantages of reforms to enable DERs include:

- Deployment of DER is more targeted to use cases and geographic areas where the benefits to the total electric system (including customer-side, distribution, and transmission) exceed the costs, enhancing efficiency for all users.
- Customer preferences are enhanced without imposing costs on other customers.
- Electric services (like electric transport and heat) can be expanded with reduced increases in distribution system cost and enhance resiliency from on-site generation.

POTENTIAL DISADVANTAGES OF REFORMS TO ENABLE DER

Potential disadvantages of reforms to enable DERs include:

- Implementation challenges and care to ensure a wide variety of DERs are fully enabled to provide their potential services.
- Some types of DER programs require investment costs for controls and dispatchability (though if developed by third-party aggregators, the associated costs can be borne by the private companies rather than customers).

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

The opportunities to better activate cost-effective DERs include through enhanced utility rates (as discussed above), joining RTO markets and enabling DERs to fully participate in providing RTO-defined system services such as capacity and ancillary services, opening retail markets sufficiently to enable DERs to operate against unique and innovative retail structures, and enabling DERs to offer their services into all-source procurements. Pursuing one or more of these avenues may require third-party DER providers and aggregators to be explicitly enabled in both law and regulation within the respective reform areas.

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[208] A.W. Thompson and Y. Perez, Vehicle-to-Everything (V2X) energy services, value streams, and regulatory policy implications, Energy Policy, Volume 137, February 4, 2020.

G. Third-Party Energy Efficiency Administrator

DESCRIPTION AND RELEVANT CASE STUDIES

Energy Efficiency (EE) programs are designed to reduce the energy used by electric appliances such as heaters, air conditioning, other home appliances, manufacturing, electronics, etc. EE programs can include rebates for home weatherization, heating electrification, and more efficient lighting, air conditioning, or refrigerators. EE programs can save costs for customers, increase grid reliability, and result in health benefits.[209] Energy efficiency programs can be especially beneficial for low to moderate-income households. Such households tend to have disproportionately high energy bill burdens and are more likely to live in older housing with less insulation and (in some regions) more expensive heating fuel.[210] Energy efficiency improvements can therefore result in significantly lower bills for some of these customers.[211]

In most regions, energy efficiency programs are run and administered by utilities. However, utility cost recovery mechanisms (such as recovery of fixed costs through rates that are based on purchase volumes) can provide a disincentive to the utility for any reduction in sales. While such tensions are generally workable, and can yield successful EE programs, utilities, regulators, and other stakeholders sometimes view them as a problem that warrants alternative solutions.[212]

One solution would mandate the creation of a third-party entity (typically a state agency or non-profit) to deliver energy efficiency services. Third-party entities are typically established by the state and are funded by a ratepayer surcharge. The third-party EE provider acts as a separate organization that designs and administers EE programs, funding allocations, and reviews measurement and verification of program effectiveness.[213] The programs and the third-party EE administrator may also be subject to state commission oversight.

Jurisdictions that have third-party energy efficiency administrators in the U.S. include New York, Vermont, and Wisconsin.[214] In New York, the New York State Energy Research and Development

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209 International Energy Agency, Capturing the Multiple Benefits of Energy Efficiency, 2014.

210 American Council for Energy-Efficient Economy (ACEEE), "Low-Income Energy Efficiency Programs," January 19, 2023.

211 Environmental Protection Agency (EPA), Efficiency Vermont Case Study, accessed January 18, 2023.

212 California Public Utilities Commission (CPUC), Energy Efficiency Policy Manual. April 2020.

213 Environmental Protection Agency (EPA), "Local Utilities and Other Energy Efficiency Program Sponsors," accessed January 25, 2023.

214 We note there are also third-party EE administrators in Canada in Ontario and New Brunswick.

Authority (NYSERDA) runs energy efficiency focused programs such as "Pay for Performance."[215] Pay for Performance allows third parties that bundle efficiency to bid for energy saving contracts. Vermont has Efficiency Vermont, an energy efficiency utility which is a non-profit organization overseen by the Vermont Public Utility Commission. Efficiency Vermont is funded by a surcharge on customer bills and offers a wide variety of energy efficiency programs, including educational programs, rebates for ventilation equipment, and efficient light bulb programs.[216] Wisconsin has "Focus on Energy," a statewide energy efficiency program funded by ratepayers through utilities.[217] Utilities recover the costs of funding the program through a rate surcharge. Focus on Energy delivered >$1 billion in economic benefits between 2010–2017 with $4.36 in benefits for every $1 invested in energy efficiency in 2017.[218]

POTENTIAL ADVANTAGES

Potential advantages of introducing a third-party energy efficiency administrator include:

- Singular focus on EE could mean more scope for innovative and effective EE programs.
- Overcomes potential misaligned incentives with utility administration.
- May activate a larger number and variety of EE providers.
- Possible efficiencies with one entity for the whole state and reduced work for utilities.

POTENTIAL DISADVANTAGES

Potential disadvantages of introducing a third-party energy efficiency administrator include:

- Implementation costs and time.
- May not be necessary in situations where utility programs are already achieving high success, eliminating effective utility programs would lose established infrastructure, experience, and customer relations that already exist within the utility.
- Requires sufficiently long funding commitment for institution-building.

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[215] NYSERDA and National Grid, Pay-for-Performance Initiative, September 2019.

[216] U.S. Department of Energy (DOE), "Energy Efficiency Policies and Programs," accessed January 19, 2023.

[217] Midwest Energy Efficiency Alliance, "Midwest Energy Efficiency Alliance," accessed January 20, 2023.

[218] Midwest Energy Efficiency Alliance, Energy Efficiency, accessed January 20, 2023.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

In South Carolina, Energy Efficiency programs are currently administered by utilities. Costs for energy efficiency programs are passed through to ratepayers or amortized over time to retain a share of savings. To establish a third-party energy administrator, legislation would have to be passed. The scope of the third-party EE administrator could be expansive for the entire state and cover all EE programs, or could be subject to PSC oversight such that some programs could be offered on a statewide basis while others are targeted in some utility areas if minimum EE targets are not already achieved through existing utility programs. The PSC would regulate compensation for the independent administrator through a surcharge on all bills in South Carolina.

H. Recommendations for Retail Market Reforms

Based on these analyses of retail reforms summarized above, we recommend that South Carolina consider the following options:

- **Pursue a path toward greater regional coordination via an EIM or RTO wholesale market**, as to support enabling additional retail rate choices to retail customers. Entering an RTO will immediately increase competitive forces by empowering cooperative and municipal utilities in South Carolina to consider a greater variety of self-supply and contractual options for securing their energy supply.
- **Authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices** to South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, green tariffs and related green energy options, and other rate designs to enhance efficiency.
- **Introduce partial retail choice for large C&I customers**, enabling businesses that are large, sophisticated energy consumers to negotiate rates, self-supply with clean energy, participate in RTO markets as demand-side resources, and optimize their own consumption.
- **Introduce a path for Community Choice Aggregation**, enabling local communities to pursue environmental goals and negotiate rates.
- **Defer consideration of retail choice for residential and small business customers** until after other reforms are implemented. Revisit the option to expand retail choice to all consumers after gaining experience with wholesale market participation, partial retail choice, and the other market reforms discussed above.
- **Enable distributed energy resources and demand response** from third-party providers to compete in all-source supply solicitation, both within competitive IRP-based all-source procurement processes and within RTO markets.
- **Authorize the PSC to appoint a third-party EE administrator** to support energy efficiency program development in utility territories where substantial cost-effective EE opportunities exists to reduce customer electricity bills but that have not been fully pursued under existing structures.

List of Acronyms

ACEEE	American Council for Energy-Efficient Economy
ASCS	All-Source Competitive Solicitation
BA	NERC Balancing Authority
BAA	NERC Balancing Authority Area
C&I	Commercial & Industrial
CAISO	California Independent System Operator
CEC	California Energy Commission
CCA	Community Choice Aggregation
COPUC	Colorado Public Utilities Commission
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CP	Coincident Peak
CSU	Colorado Springs Utilities
CTCA	Carolinas Transmission Coordination Agreement
DA	Day Ahead
DCA	Department of Consumer Affairs
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Demand Response
DSO	Distribution System Operator
ECAR	East Central Area Reliability Council
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EIM	Energy Imbalance Market
EIPC	Eastern Interconnection Planning Collaborative
EIS	Energy Information System
EPA	Environmental Protection Agency
EPE	El Paso Electric
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission

FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
G&T	Generation and Transmission
IESO	Independent Electricity System Operator (of Ontario)
IOU	Investor Owned Utility
ISO	Independent System Operator
IPP	Independent Power Producer
IRM	Installed Reserve Margin
IRP	Integrated Resource Plan
JDA	Joint Dispatch Agreement
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LMP	Locational Marginal Price
LTSG	Long Term Study Group
MAIN	Mid-American Interpool Network
MAPP	Midcontinent Area Power Pool
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
NCP	Non-Coincident Peak
NEM	Net Energy Metering
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NERP	North Carolina Energy Regulatory Process
NESCOE	New England States Committee on Electricity
NIPSCO	Northern Indiana Public Service Company
NREL	National Renewable Energy Laboratory
NRRI	National Regulatory Research Institute
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations & Maintenance
ORS	Office of Regulatory Staff
PJM	PJM Interconnection
PMPA	Piedmont Municipal Power Association
PNM	Public Service Company of New Mexico
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSCO	Public Service Company of Colorado

PSO	Power System Optimizer
PSC	Public Service Commission
PTR	Peak Time Rebates
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act of 1978
QF	Qualifying Facility
RA	Resource Adequacy
RC	NERC Reliability Coordinator
RFP	Request for Proposal
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
Santee Cooper	South Carolina Public Service Authority
SEC	Securities Exchange Commission
SEEM	Southeast Energy Exchange Market
SERC	Southeastern Electric Reliability Council
SOCO	Southern Company
SPE	Special Purpose Entity
SPP	Southwest Power Pool
TOP	NERC Transmission Operator
TOU	Time-of-Use
TVA	Tennessee Valley Authority
VACAR	The group of four companies consisting of Duke Energy Carolinas, Duke Energy Progress, South Carolina Public Service Authority, and Dominion South Carolina
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WRAP	Western Resource Adequacy Program

Appendix A: Load Diversity Analysis

South Carolina + PJM	Duke Energy Progress Combined	Duke Energy Carolinas	PJM	Santee Cooper	Dominion Energy	Regional Total	South Carolina Total	South Carolina Savings %
South Carolina Share of Load	10%	29%	0%	100%	100%			
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
A. Original 1-NCP Peak								
2011	13,315	19,644	158,043	5,676	4,885	201,563	17,507	
2012	13,193	19,473	154,339	5,387	4,761	197,153	17,033	
2013	12,523	18,239	157,509	5,029	4,574	197,874	16,068	
2014	14,215	20,799	141,678	5,673	4,853	187,218	17,892	
2015	15,569	21,101	143,633	5,869	4,970	191,142	18,426	
2016	13,298	20,671	152,177	4,794	4,807	195,747	16,840	
2017	14,534	20,120	145,637	4,989	4,701	189,981	16,894	
2018	15,519	21,620	150,670	5,203	4,756	197,768	17,690	
2019	13,669	20,597	151,570	4,558	4,714	195,108	16,526	
2020	13,233	20,398	144,588	4,467	4,586	187,272	16,207	
2021	13,046	20,310	148,770	4,634	4,573	191,333	16,317	
Average	**13,829**	**20,270**	**149,874**	**5,116**	**4,744**	**193,833**	**17,036**	
B. PJM-South Carolina 1-CP Peak								
2011	13,154	19,305	158,043	5,129	4,720	200,351	16,682	
2012	12,574	18,382	154,339	4,733	3,988	194,016	15,232	
2013	11,954	17,829	157,509	4,638	4,025	195,955	14,954	
2014	14,215	20,246	137,998	5,673	4,853	182,985	17,734	
2015	12,491	19,884	143,065	4,941	4,646	185,027	16,520	
2016	13,079	20,236	150,826	4,541	4,618	193,300	16,251	
2017	12,640	19,878	145,325	4,298	4,200	186,341	15,444	
2018	12,405	19,597	150,670	4,081	4,116	190,869	15,039	
2019	12,563	20,359	151,570	4,290	4,372	193,154	15,738	
2020	13,207	20,087	144,588	4,074	4,175	186,131	15,311	
2021	13,046	20,147	148,216	4,379	4,520	190,308	15,963	
Average	**12,848**	**19,632**	**149,286**	**4,616**	**4,385**	**190,767**	**15,897**	
C. Savings (A - B)								
2011	161	339	0	547	165	1,212	825	4.7%
2012	619	1,091	0	654	773	3,137	1,801	10.6%
2013	569	410	0	391	549	1,919	1,114	6.9%
2014	0	553	3,680	0	0	4,233	158	0.9%
2015	3,078	1,217	569	928	324	6,116	1,906	10.3%
2016	219	435	1,351	253	189	2,447	588	3.5%
2017	1,894	242	312	691	501	3,640	1,449	8.6%
2018	3,114	2,023	0	1,122	640	6,899	2,650	15.0%
2019	1,106	238	0	268	342	1,954	788	4.8%
2020	26	311	0	393	411	1,141	896	5.5%
2021	0	163	555	255	53	1,026	355	2.2%
Average	**981**	**638**	**588**	**500**	**359**	**3,066**	**1,139**	**6.6%**

Notes/Sources: FERC Form 714.

SERTO	PowerSouth Energy Cooperative	Associated Electric Cooperative, Inc.	Duke Energy Progress Combined	Duke Energy Carolinas	Louisville Gas and Electric Company and Kentucky Utilities Company	South Carolina Public Service Authority	Dominion Energy South Carolina, Inc.	Southern Company Services, Inc.	Tennessee Valley Authority	Regional Total	South Carolina Total	South Carolina Savings %
SC Share of Load	0%	0%	10%	29%	0%	100%	100%	0%	0%			
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)			
A. Original 1-CP Peak												
2011	2,081	4,376	13,263	19,515	7,046	5,415	4,855	41,149	30,815	128,514	17,174	
2012	1,872	4,301	13,072	19,276	7,153	5,304	4,689	41,074	30,796	127,536	16,809	
2013	1,742	3,953	12,406	18,120	6,691	4,928	4,467	38,149	28,131	118,586	15,814	
2014	2,361	4,639	14,098	20,088	7,272	5,500	4,638	43,538	32,793	134,927	17,289	
2015	2,117	4,412	14,160	20,364	6,936	5,439	4,810	43,311	31,602	133,152	17,485	
2016	1,887	4,281	13,160	20,345	6,685	4,749	4,749	42,343	29,552	127,751	16,630	
2017	1,976	4,400	13,409	19,946	6,582	4,735	4,662	41,587	29,658	126,953	16,438	
2018	2,340	5,070	15,112	20,821	6,831	5,072	4,710	42,694	31,400	134,049	17,243	
2019	1,938	4,845	13,065	20,440	6,744	4,496	4,679	42,806	29,404	128,417	16,325	
2020	1,978	4,486	13,149	20,161	6,495	4,420	4,569	41,363	28,783	125,404	16,067	
2021	2,087	5,736	12,901	20,295	6,659	4,520	4,554	44,558	30,268	131,577	16,165	
Average	2,035	4,591	13,436	19,943	6,827	4,961	4,671	42,052	30,291	128,806	16,676	
B. SERTO 1-CP Peak												
2011	1,839	4,005	13,072	18,856	6,550	5,318	4,749	40,600	30,075	125,062	16,762	
2012	1,791	3,998	12,707	18,832	7,057	5,068	4,529	40,970	30,677	125,627	16,249	
2013	1,602	3,568	11,813	17,690	6,637	4,601	4,172	37,433	27,856	115,369	15,010	
2014	2,288	4,111	14,079	20,088	6,863	5,435	4,530	43,285	32,109	132,786	17,114	
2015	2,057	4,018	14,090	20,283	6,810	5,411	4,772	42,336	31,023	130,798	17,389	
2016	1,686	3,445	12,844	20,101	6,489	4,602	4,623	41,836	29,043	124,669	16,256	
2017	1,698	4,139	12,466	19,739	6,534	4,250	4,235	40,916	29,249	123,225	15,374	
2018	2,250	4,403	14,545	20,490	6,658	4,968	4,633	41,876	30,618	130,441	16,911	
2019	1,793	3,905	12,373	19,792	6,246	4,220	4,421	42,310	29,246	124,304	15,535	
2020	1,822	3,759	12,986	20,030	6,180	4,253	4,344	40,728	28,260	122,362	15,621	
2021	1,897	4,521	12,290	20,044	6,295	4,244	4,365	44,451	30,039	128,144	15,567	
Average	1,884	3,988	13,024	19,631	6,574	4,761	4,488	41,522	29,836	125,708	16,163	
C. Savings (MW) (A - B)												
2011	242	371	191	659	496	98	106	548	740	3,451	411	2.4%
2012	82	303	365	444	96	236	161	104	119	1,910	560	3.3%
2013	141	385	593	430	54	327	295	717	276	3,217	803	5.1%
2014	74	529	19	0	410	65	108	253	684	2,140	175	1.0%
2015	61	394	71	82	126	28	38	976	579	2,354	96	0.5%
2016	201	836	316	245	197	147	126	506	509	3,082	374	2.3%
2017	278	261	943	206	49	485	427	672	409	3,728	1,064	6.5%
2018	90	667	567	331	173	104	78	818	782	3,608	332	1.9%
2019	146	940	692	649	499	277	258	496	158	4,113	789	4.8%
2020	157	727	163	132	315	166	226	635	523	3,043	446	2.8%
2021	190	1,215	611	252	364	276	189	108	230	3,434	598	3.7%
Average	**151**	**603**	**412**	**312**	**252**	**201**	**183**	**530**	**455**	**3,098**	**514**	**3.1%**

Notes/Sources: FERC Form 714.

Appendix B: Investment Savings from Partial or Full Reliance on Competitive Supply

High Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	167	0	414	553	1,522	1,698	1,997	2,806	3,017	3,827	4,004	4,157	4,441	4,619	4,799	4,981	5,164	5,348
IRP Planned Capacity	MW	[5]	20,842	20,813	20,936	21,074	21,210	21,386	21,441	21,565	21,777	21,977	22,154	22,307	22,590	22,769	22,949	23,131	23,314	23,498
Incremental Capacity Cost	($/MW-Day)	[6]	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320
Net Cost of Incremental Capacity	($ Mln)	[7]	$19	$0	$48	$65	$178	$198	$233	$328	$352	$447	$468	$486	$519	$540	$561	$582	$603	$625
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	249	1,047	1,240	2,034	2,196	2,335	2,595	2,759	2,923	3,090	3,257	3,426
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,693	19,807	20,000	20,183	20,345	20,485	20,745	20,909	21,073	21,240	21,407	21,576
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)
Incremental Capacity Cost	($/MW-Day)	[14]	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320
PJM Market Price	($/MW-Day)	[15]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$29	$122	$145	$238	$256	$273	$303	$322	$341	$361	$380	$400
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$42	$54	$35	$36	$40	$46	$52	$58	$64	$70	$75	$75	$75	$75	$75	$75
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(42)	(54)	(35)	(36)	(11)	77	93	180	193	203	228	247	266	285	305	325
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$62**	**$28**	**$90**	**$118**	**$213**	**$234**	**$244**	**$251**	**$259**	**$267**	**$275**	**$282**	**$291**	**$293**	**$295**	**$296**	**$298**	**$300**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	14	28	89	111	133	169	185	200	216	232	248
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$62**	**$28**	**$90**	**$118**	**$213**	**$234**	**$261**	**$314**	**$324**	**$358**	**$357**	**$352**	**$349**	**$355**	**$360**	**$366**	**$371**	**$377**

Sources and Notes:

All values expressed in nominal U.S. dollars.

[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.

[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.

[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.

[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.

[5]: [3] + [4].

[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.

[7]: [4] x [6] x 365.

[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.

[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.

[12]: [10] + [11].

[13]: [9] - [12].

[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

Low Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be equal to the incremental capacity cost. 2036 onward: incremental capacity cost.

[16]: [11] x [14]x 365.

[17]: -[13] x [15] x 365.

[18]: [16] - [17].

[19]: [7] - [18].

[23]: [21] - [22].

[25]: [23] x [24] x 365.

[26]: [7] - [25].

Reference Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	0	0	269	253	1,222	1,398	1,697	2,506	2,717	3,527	3,704	3,857	4,141	4,319	4,499	4,681	4,864	5,048
IRP Planned Capacity	MW	[5]	20,675	20,572	20,791	20,774	20,910	21,086	21,141	21,265	21,477	21,677	21,854	22,007	22,290	22,469	22,649	22,831	23,014	23,198
Incremental Capacity Cost	($/MW-Day)	[6]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Capacity	($ Mln)	[7]	$0	$0	$30	$28	$137	$157	$191	$282	$305	$397	$416	$434	$465	$486	$506	$526	$547	$568
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	0	747	940	1,734	1,896	2,035	2,295	2,459	2,623	2,790	2,957	3,126
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	19,507	19,700	19,883	20,045	20,185	20,445	20,609	20,773	20,940	21,107	21,276
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Incremental Capacity Cost	($/MW-Day)	[14]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
PJM Market Price	($/MW-Day)	[15]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$0	$84	$106	$195	$213	$229	$258	$276	$295	$314	$332	$351
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$42	$54	$35	$36	$27	$29	$32	$36	$40	$43	$47	$47	$47	$47	$47	$47
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	55	73	159	173	185	211	229	248	266	285	304
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$43**	**$28**	**$72**	**$82**	**$172**	**$193**	**$218**	**$226**	**$232**	**$238**	**$243**	**$248**	**$255**	**$256**	**$258**	**$260**	**$262**	**$263**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	14	28	89	111	133	169	185	200	216	232	248
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$43**	**$28**	**$72**	**$82**	**$172**	**$193**	**$218**	**$268**	**$277**	**$308**	**$306**	**$300**	**$296**	**$301**	**$305**	**$310**	**$315**	**$320**

Sources and Notes:

All values expressed in nominal U.S. dollars.

[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.

[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.

[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.

[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.

[5]: [3] + [4].

[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.

[7]: [4] x [6] x 365.

[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.

[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.

[12]: [10] + [11].

[13]: [9] - [12].

[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

Low Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be equal to the incremental capacity cost. 2036 onward: incremental capacity cost.

[16]: [11] x [14]x 365.

[17]: -[13] x [15] x 365.

[18]: [16] - [17].

[19]: [7] - [18].

[23]: [21] - [22].

[25]: [23] x [24] x 365.

[26]: [7] - [25].

Low Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	0	0	269	124	1,022	1,198	1,497	2,306	2,517	3,327	3,504	3,657	3,941	4,119	4,299	4,481	4,664	4,848
IRP Planned Capacity	MW	[5]	20,675	20,572	20,791	20,645	20,710	20,886	20,941	21,065	21,277	21,477	21,654	21,807	22,090	22,269	22,449	22,631	22,814	22,998
Incremental Capacity Cost	($/MW-Day)	[6]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Capacity	($ Mln)	[7]	$0	$0	$30	$14	$115	$135	$168	$259	$283	$374	$394	$411	$443	$463	$483	$504	$524	$545
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	0	547	740	1,534	1,696	1,835	2,095	2,259	2,423	2,590	2,757	2,926
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	19,307	19,500	19,683	19,845	19,985	20,245	20,409	20,573	20,740	20,907	21,076
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Incremental Capacity Cost	($/MW-Day)	[14]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
PJM Market Price	($/MW-Day)	[15]	$50	$34	$59	$84	$109	$134	$159	$184	$208	$233	$258	$283	$308	$308	$308	$308	$308	$308
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$0	$61	$83	$172	$191	$206	$236	$254	$272	$291	$310	$329
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$45	$60	$40	$41	$32	$20	$23	$26	$28	$31	$34	$34	$34	$34	$34	$34
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(45)	(60)	(40)	(41)	(32)	41	60	147	162	175	202	220	239	257	276	295
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$43**	**$28**	**$75**	**$74**	**$155**	**$176**	**$200**	**$218**	**$223**	**$227**	**$232**	**$236**	**$241**	**$243**	**$245**	**$246**	**$248**	**$250**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$59	$84	$109	$134	$159	$184	$208	$233	$258	$283	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(45)	(60)	(40)	(41)	(32)	17	33	105	132	159	202	220	239	257	276	295
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$43**	**$28**	**$75**	**$74**	**$155**	**$176**	**$200**	**$243**	**$249**	**$269**	**$262**	**$252**	**$241**	**$243**	**$245**	**$246**	**$248**	**$250**

Sources and Notes:
All values expressed in nominal U.S. dollars.

[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.
[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.
[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.
[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.
[5]: [3] + [4].
[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.
[7]: [4] x [6] x 365.
[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.
[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.
[12]: [10] + [11].
[13]: [9] - [12].
[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

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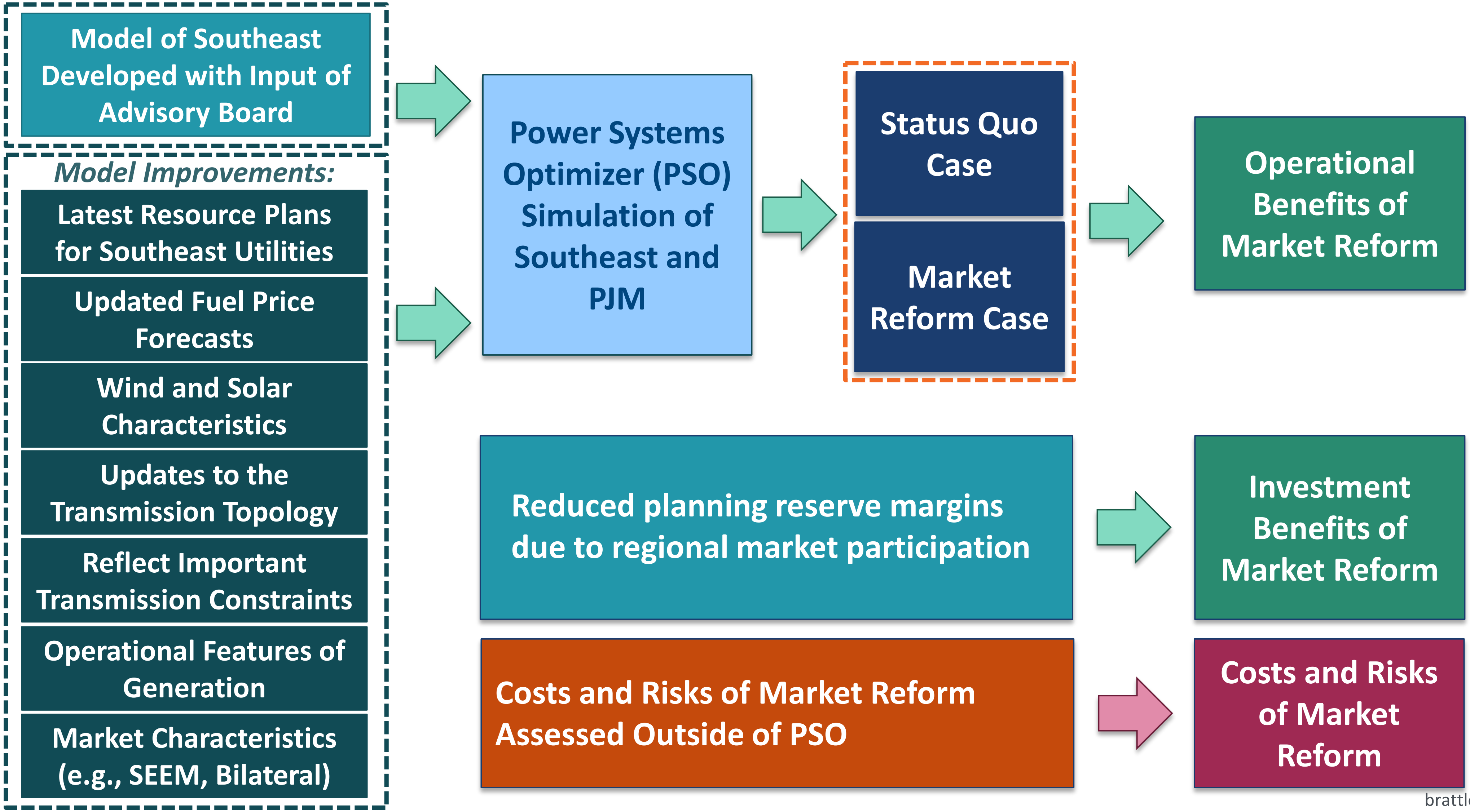
[17]: -[13] x [15] x 365.
[18]: [16] - [17].
[19]: [7] - [18].
[23]: [21] - [22].
[25]: [23] x [24] x 365.
[26]: [7] - [25].

APPENDIX C: Operational Simulation of Regional Wholesale Market Options for South Carolina

The Brattle Group
April 2023

Contents

Study Framework and Benefits Calculation



Simulated Market Reform Options

We simulated four different market reform scenarios representing part of the spectrum of possible market reform options.

Market Reform Options

- **Joint Dispatch Agreement in the Carolinas**
- **Energy Imbalance Market in the Southeast**
- **Southeast RTO (w/ Vertically Integrated Utility)**
- **Carolinas in PJM RTO (w/ Vertically Integrated Utility**

The analysis started with an assessment of the Status Quo, including the SEEM

- We modeled the entire Southeast, incorporating Advisory Board members' data
- The SEEM footprint reflected all announced membership as of February 1, 2023
- The EIM and Southeast RTO footprints cover the existing SEEM footprint

Simulated one 2030 scenario for each reform option and compared it against the Status Quo

- 2030 was chosen as a single proxy year to represent average savings over the next two decades

Overview of Modeling Approach

Simulations of the Carolinas within the broader Southeast + PJM region to assess operational benefits of market reforms

Utilized Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the Southeast
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Used a pre-populated model of the Southeast region provided by Enelytix
- Updated modeling assumptions to reflect the most recent utility resource plans and forecasts of system conditions and costs
- Hourly granularity due to limited data availability, but model can be enhanced for sub-hourly analysis

ENELYTIX® powered by PSO

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs because it can simulate multiple stages of system operator decision making

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions like the Southeast.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.

Simulating Several Wholesale Market Cycles

PSO simulates sequential decision cycles representing operational decisions at different points in time and with varying information about system conditions. Subsequent cycles realize uncertain outcomes, such as forced generation outages

- Market structures (e.g. bilateral, SEEM, EIM, RTO) are differentiated in our model via the following assumptions:
  - Wheeling fees and hurdle rates between utilities
  - Transmission availability for market transactions
  - Pooled (or not pooled) unit commitment and dispatch decisions
  - Reserve requirements

Day-Ahead Cycle	SEEM Cycle	Real-Time Cycle
Unit Commitment and Bilateral Trading	**SEEM Trading**	**Real-Time Dispatch**
– In non-RTO cases, resources committed and dispatched on utility-specific basis; DA bilateral trades occur – In RTO, unit commitment and dispatch optimized across footprint	– Bilateral SEEM trades take place subject to available transmission on defined contract paths between BAs	– Dispatch adjustments on utility-specific basis in non-RTO cases – In RTO, EIM, and JDA, dispatch optimization subject to physical transmission constraints

Simulating Several Wholesale Market Cycles (cont'd)

The model setup for the South Carolina wholesale market simulation effort contains four cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. The four cycles (three time frames) simulated in this model are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various PJM sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **SEEM Cycle:** the model simulates SEEM market activity through one-hour optimization horizons. Utilities are assumed to offer unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits, into the market. We limit SEEM trading volumes based on input about expected participation from the Carolina utilities. No fast-start unit commitment is allowed in the SEEM market due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulated the operation of the real-time imbalance markets, such as through EIM and RTO transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment).

These cycles will take on different assumptions, depending on market structure. In a bilateral (Status Quo) setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In the RTO and EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch. In the RTO setting, there would be no hurdle rates between market participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis. In the EIM Case, the day-ahead cycles continue to operate like the bilateral case, while the real-time cycle operates like the RTO cases.

Operational Benefit Metrics: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is the sum of production costs and purchased power less off-system sales revenue:

- **(+) Production costs** (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities
- **(+) Cost of bilateral and market purchases** valued at the BAA's load-weighted energy price
- **(−) Revenues from bilateral and market sales** valued at the BAA's generation-weighted energy price

The APC is calculated for the Status Quo Case (including SEEM) and for each of the four market reform cases to determine the reduction in APC due to market reform

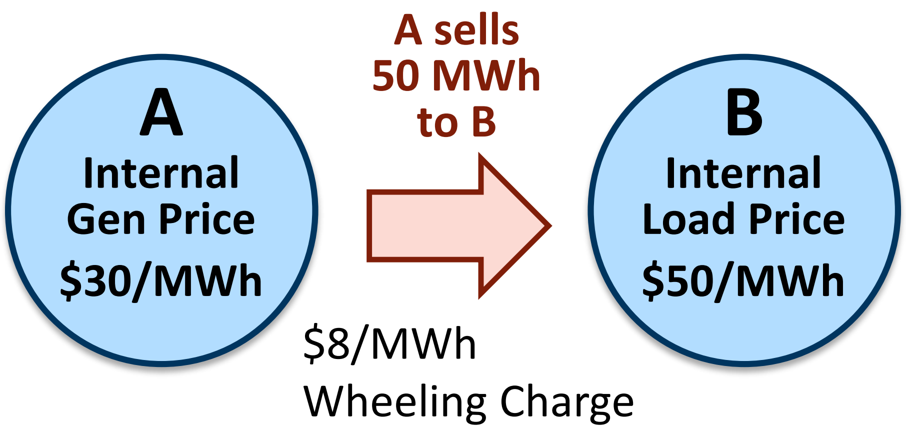
- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

Operational Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms.

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/RTO)

EXAMPLE:



The APC metric only uses internal prices for purchase cost and sales revenues, which does not capture part of the value:

- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

Modeling Steps

Step 1 – Benchmarked and Calibrated the Model

- Simulated the Southeast using 2020 inputs to verify system dynamics
- Ensured that SEEM member entities and PJM were correctly represented
- Adjusted model based on stakeholder input

Step 2 – Created 2030 Status Quo Case

- Modeled SEEM market
- Sought input from the Advisory Board
- Updated inputs to forecasted 2030 values

Step 3 – Simulated Market Reform Options

- Modeled four individual market reform options
- Compared benefit metrics against status quo case

Simulated Market Reform Benefits Are Conservative

The following factors ensure that modeled benefits associated with market reform are conservative:

- **Forecast uncertainty.** The simulations do not account for day-ahead forecast error of renewable generation and load. We apply the same hourly load and renewable generation in the day-ahead unit commitment and dispatch optimization, as in the real-time cycle. Therefore, our simulations of the real-time balancing cycle do not capture the benefit regional wholesale markets provide by optimizing dispatch to manage more challenging real-time conditions due to forecasting uncertainty.
- **Hourly modeling.** The modeling simulates hourly granularity of real-time market conditions (without uncertainty). This will understate the additional intra-hour, real-time benefits of a JDA, EIM, and RTO and result in understated estimates of EIM and RTO benefits relative to the Status Quo.
- **Natural gas price volatility.** The model uses natural gas fuel price forecasts provided by the Advisory Board utility members. Forecasts apply average daily price volatility and average geographic differences in prices, which does not capture periods of extreme volatility and large regional fluctuations in gas prices, such as those experienced during severe winter weather. Modeling natural gas price volatility in line with these events would increase the operational benefits of all regional market options studied by creating larger gains from trading power across the regional footprint.
- **Normalized weather conditions.** We do not model heat waves, cold snaps, or other weather events and uniquely challenging market conditions. Historical experience has shown that such events significantly increase production costs and regional trading values. Improved market integration would help to cope with such events at a lower cost, resulting in increased benefits that are not captured in our simulations.
- **Transmission outages.** The model does not include transmission outages, which understates the efficiency gains achieved in a regional market. The optimization performed in a wholesale market can lower the cost of re-dispatching the system during transmission outages by drawing on resources from across the footprint.

Simulated Market Reform Benefits Are Conservative (cont'd)

- **2030 transmission upgrades.** Our analysis assumes that only the existing transmission assets, or planned assets expected to be online by 2030, are available. Therefore, the net benefits reported are what is feasible given that transmission infrastructure. If South Carolina utilities build new transmission infrastructure that increases the ability to trade across the market footprint, with the approval of the South Carolina PSC, the benefits of joining EIM or a regional market would increase.
- **Status Quo market efficiency.** The simulations assume each Balancing Area fully optimizes its resources based on a security-constrained optimal unit commitment and dispatch. In addition, simulated SEEM transactions in our 2030 Status Quo Case are almost five times higher than the observed historical transactions in SEEM since its launch (comparing the current SEEM footprint, excluding Florida utilities, with the same footprint in the model). Our 2030 representation of the Status Quo, including SEEM, thus appears to be significantly more efficient than the actual market. This means that the incremental benefits from the other market reform options studied (the JDA, EIM, and two RTO options) would be greater than estimated.

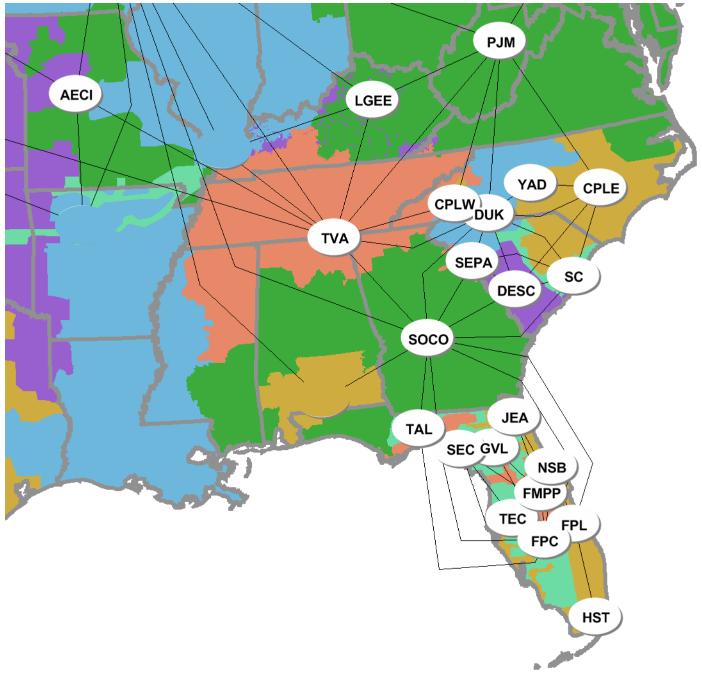
Modeling Assumptions

Model Footprint

We modeled a large portion of the Eastern Interconnect, including South Carolina and the rest of VACAR, SERC, FRCC, and PJM, to represent the SEEM market and relevant neighboring trading partners

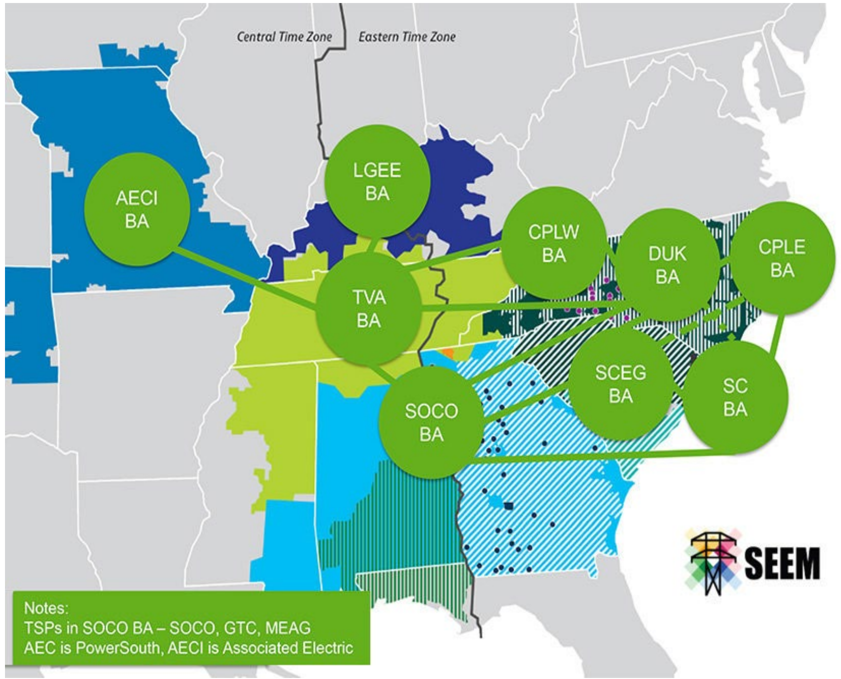
- We included all current SEEM members, including the Florida utilities currently in the process of joining
- We aggregated balancing footprints and trading barriers for each modeled case
- Trading with external areas (e.g. NYISO, MISO, and SPP) is modeled as fixed interchanges matching 2020 hourly transactions

Model Footprint



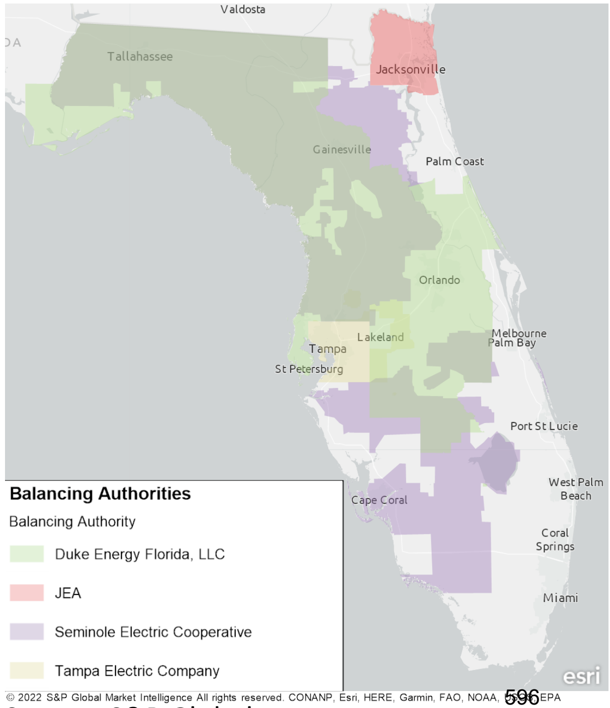
Source: NERC, “NERC Balancing Authority Areas”, October, 2019.

Initial SEEM Footprint



Source: Southeast Energy Exchange Market.

Additional Florida SEEM Participants



596

Source: S&P Global.

Demand Assumptions

We relied on Advisory Board member utility input, FERC-714 data, and utility IRPs for peak and total demand assumptions

- PJM demand forecasts are based on PJM's 2021 zonal load forecasts (source)
- South Carolina utilities are modeled as the planning areas reported in FERC-714, including municipal and co-op utilities' loads in the projections for Duke and Santee Cooper. Duke is represented as a single balancing authority area, reflecting plans to unify Duke Energy Carolinas and Duke Energy Progress subject to regulatory approval

Load shapes are based on historical hourly demand profiles from the FERC-714 filings, with scaling to 2030 peak and total energy values

2030 Demand Assumptions

Utility	Total Load (GWh)	Peak Load (GW)
Duke Energy Progress and Duke Energy Carolinas (in both North and South Carolina)	171,490	35.8
Santee Cooper	28,697	5.6
Dominion South Carolina	25,078	4.8
PJM (without South Carolina, without Duke in North Carolina)	820,584	158.8
Southeast for purposes of modeling SEEM, EIM, and Southeastern RTO cases (without South Carolina, without Duke in North Carolina)	559,710	100.6

Capacity Mix

2030 capacity mixes are based on integrated resource plans, Advisory Board member utility data for the Carolinas, and other public sources, such as the EIA and trade press

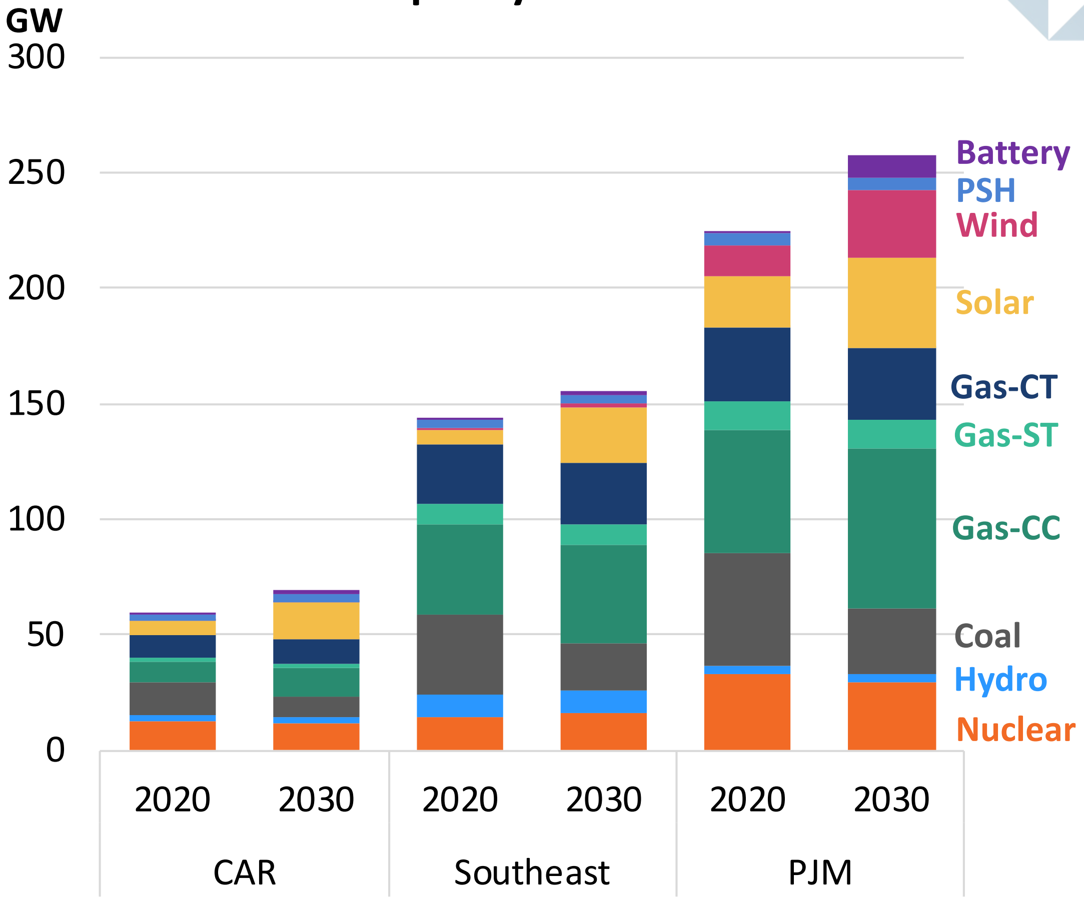
2030 capacity mixes reflect increasing renewables deployment and coal retirements

- PJM resource mix assumes member-states meet 2030 RPS targets
- Renewables output profiles are based on data from NREL (day-ahead forecasting uncertainty was not implemented)
- Seasonal hydro output variation reflects an average year, based on input from stakeholders

There is uncertainty about the Winyah coal plant's replacement

- Based on conversations with Santee Cooper and Central Electric Co-Op, we assume that these two entities will procure replacement capacity separately
- We model the Winyah replacement as two combined cycle gas plants with capacities equal to Santee Cooper's and Central Electric' ownership stakes in Winyah

Modeled Capacity Mix 2020 vs. 2030



Notes: Carolinas includes all of Duke, Dominion SC, and Santee Cooper. Southeast includes all non-Carolinas SEEM members. "PJM" represents the current footprint, not including the Carolinas.

2030 Capacity Updates

The evolution of the Southeast and PJM resource mix is marked by coal being replaced with renewables and storage

- Tables indicate changes from 2022-2030

Modeled Capacity Changes By Area

Area	Retirements			Additions		
	Coal	Gas	Nuclear	Solar	Wind	Storage
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
Duke	3,498	-	793	6,223	600	2,052
DESC	684	-	-	398	-	122
SC	1,150	-	-	1,474	-	-
SOCO	6,673	-	-	5,201	-	1,051
TVA	4,814	-	-	5,129	-	-
Rest of SERC	1,013	208	-	1,298	-	240
FRCC	1,059	-	-	16,157	-	3,516
PJM	12,821	-	1,268	13,366	15,210	9,171

Carolinas Thermal Capacity Changes

Plant	Area	Type	Capacity (MW)
Retirements			
Winyah	SC	Coal	1,150
Wateree Units 2 & 3	DESC	Coal	684
Marshall Units 1 & 2	DESC	Coal	760
Mayo Unit 1	Duke	Coal	713
Roxboro Units 1 & 2	Duke	Coal	1,053
James Rogers Unit 5	Duke	Coal	546
G.G. Allen Units 1 & 5	Duke	Coal	426
H. B. Robinson Unit 2	Duke	Nuclear	793
Additions			
TBD	SC	CC	1,119
TBD	Duke	CC	2,906
TBD	Duke	CT	1,105

Note: Santee Cooper new CC capacity represents the replacement for Winyah plant, and is modeled as two separate units owned by Santee Cooper and Central Electric Cooperative.

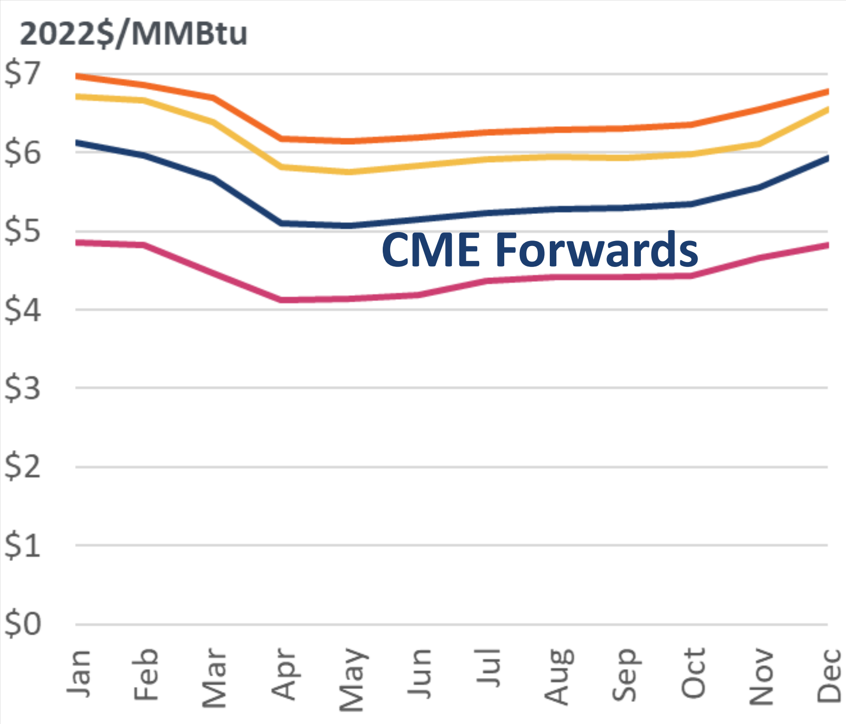
Natural Gas Prices

We used Henry Hub options quotes for 2030 from the Chicago Mercantile Exchange Group in the model

- These projections are in the middle of forecasts provided by advisory board member utilities (yellow, orange, and pink lines)
- Variation in Henry Hub price projections arises from recent gas market volatility due to the war in Ukraine and the European energy crisis

We also model unit-specific delivery adders based on data provided by advisory board member utilities and daily gas price volatility based on 2020 actual gas prices sourced from S&P Global

2030 Henry Hub Price Projections



Source: CME Group Henry Hub Natural Gas Option Quotes as of Oct 28, 2022

2030 Capacity Weighted Average Gas Price

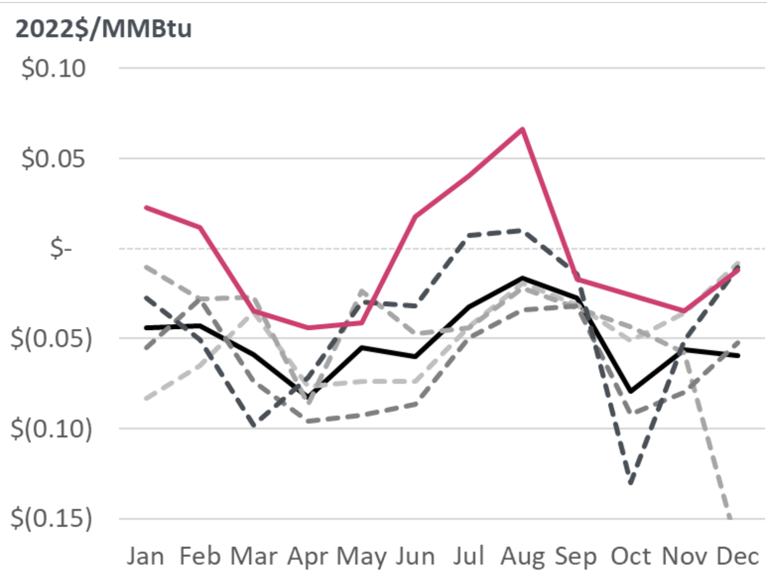
Area	$/MMBtu
Duke	$4.19
Dominion SC	$4.42
Santee Cooper	$4.06
Southern Company	$4.05
Tennessee Valley Authority	$3.99
Associated Electric Coop.	$4.07
Lousiville Gas & Electric	$3.55
Power South Cooperative	$4.60
FL-SEEM Members	$4.30
Rest of Florida	$4.23
PJM	$3.78

Natural Gas Prices (continued)

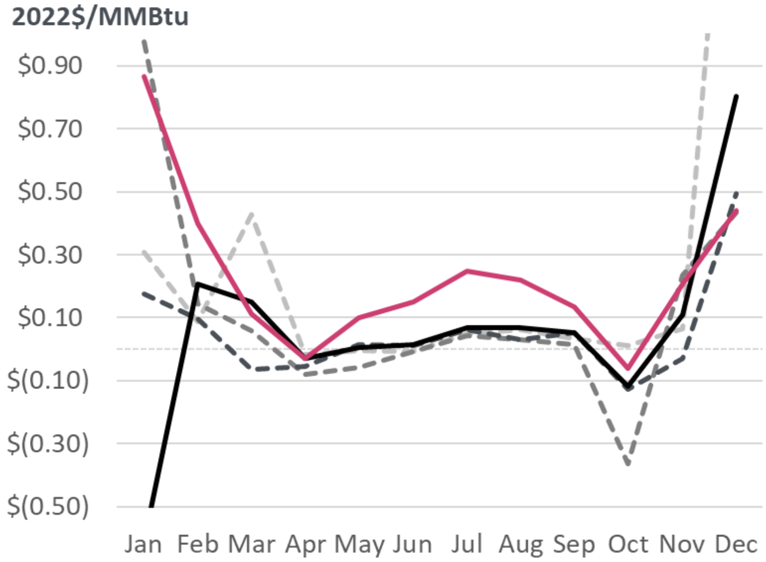
We assumed basis differentials with Henry Hub based on Advisory Board member utility input

- If multiple stakeholder basis differential forecasts were available for a given gas price hub, we chose the forecast most similar to historical basis differentials, assuming that the recent gas price volatility would subside by 2030
- If only one stakeholder forecast was available, we adjusted it to match the average 2017-2020 basis differential
- The charts below compare historical basis differentials (grayscale) to the chosen stakeholder-provided data (pink)

Transco Z4 Basis Differentials



Transco Z5 Basis Differentials



Note: Historical basis differentials sourced from S&P Global.

Legend: 2017 | 2018 | 2019 | 2020 | Historical Average | Stakeholder Data

Other Fuel Prices

Fuel oil prices are based on historical spot prices as of March 18, 2021, projected to 2030 using EIA AEO 2021 trends

Uranium prices are based on stakeholder-provided data

Plant-level coal prices are based on S&P Global power plant operations database, with 2030 projections using EIA AEO trajectories

- Annual price of coal delivered ($/ton) divided by average heat content (Btu/lbs)
- 2020 benchmarking runs apply a downward coal price adjustment for Duke, Santee Cooper, and Southern Company, per stakeholder input

All fuel prices, as well as other price inputs like startup costs and O&M prices were converted to 2022$ using a 2% inflation factor

2030 Capacity Weighted Average Coal Price

Area	$/MMBtu
Duke	$3.34
Dominion SC	$4.22
Santee Cooper	$3.58
Southern Company	$3.34
Tennessee Valley Authority	$2.83
Associated Electric Coop.	$3.01
Lousiville Gas & Electric	$2.49
Power South Cooperative	$3.90
FL-SEEM Members	$3.90
Rest of Florida	$3.60
PJM	$2.97

Note: Prices shown in 2022$.

Operating Reserve Assumptions

VACAR-South reserve sharing group's reserve requirement allocations were modeled as individually held by each member utility, based on Advisory Board utility member feedback

- If these distinctions were not already present, we split total reserve requirements into regulation, spinning, and non-spinning reserves for consistency with other market areas
  - Adding a separate regulation requirement was intended to model future flexibility needs as more solar is deployed

We assumed generic regulation, spinning, and non-spinning reserve requirements, consistent with industry experience, for utilities outside of the Carolinas where no stakeholder or public data were available

PJM operating reserve requirements are based on current PJM market guidelines, with a nested reserve area structure representing deliverability constraints into the Mid-Atlantic Dominion (MAD) sub-zone

- Spinning reserves are held to cover the largest contingency, plus a 190 MW extended requirement
  - Source: David Kimmel. PJM Synchronized Reserve Overview. 2021
  - The largest contingency does not change in the Carolinas-in-PJM case, and the MW spinning reserve requirements remain the same. However, each load serving entity purchases less spinning capacity from the market due to increased total load
- We assume a regulation requirement equal to 1% of hourly demand to represent minute-to-minute system adjustments in the hourly market model. This percentage target does not change with the Carolinas joining PJM

Southeast RTO reserve requirements are assumed to match to PJM requirements (i.e. based on largest contingency) to avoid introducing modeling artefacts

Operating Reserve Assumptions By Market Structure

Some market reforms allow participants to hold or purchase fewer operating reserves

- We modeled the EIM as an energy-only market (no optimized reserve procurement)
  - Assumed EIM participation reduces BAs' load following reserve procurement due to regional diversity in load and renewables. Lower load following needs are based on reductions in real-time hour-to-hour net load variability in the market

RTOs have optimized operating reserve procurement

- Individual utilities purchase reserves from the market, based on their share of total market footprint demand
  - Blue entries at right denote market-based reserve procurement
  - Blue PJM block indicates that PJM (without Carolinas) is 78% of the expanded PJM + Carolinas market demand, and therefore procures only 78% of the requirement of the total combined RTO

Operating Reserve Requirement Inputs

BA	Reserve Type	2030 SQ/JDA Individual Rqts % of Peak Load	EIM Individual Rqts % of Peak Load	SERTO Procured From Mkt % of Peak Load	PJM Procured From Mkt % of Peak Load
Duke	*Regulation* *Load Following* *10-Min Synchronized**	0.9% 1.4% 1.5%	1.0% 1.3% 1.5%	1.0% - 0.9%	1.0% - 0.8%
Dominion	*Regulation* *Load Following* *10-Min Synchronized**	1.0% 1.4% 0.9%	1.0% 0.2% 0.9%	1.0% - 1.0%	1.0% - 0.8%
Santee Cooper	*Regulation* *Load Following*** *10-Min Synchronized**	1.0% 6.4% 2.2%	1.0% 6.0% 2.2%	1.0% - 0.9%	1.0% - 0.8%
SERC/ FRCC	*Regulation* *10-Min Synchronized*	1.0% 2.0%	1.0% 1.9%	1.0% 0.7%	1.0% 1.9%
PJM (No CAR)	*Regulation* *10-Min Synchronized*	1.0% 190 MW + Largest Contingency	1.0% 190 MW + Largest Contingency	1.0% 190 MW + Largest Contingency	1.0% 78% of [190 MW + Largest Contingency]

** VACAR reserve sharing group allocations are assumed to be equal parts synchronized and non-synchronized requirements.*
*** Santee Cooper holds "Load Following" reserves during solar production hours only.*
Notes:
Blue entries denote market reserve procurement.
Non-spin and supplementary reserve requirements not shown, but are never limiting in the model.

Transmission Topology And Contract Path Transfer Limits

The dataset used in this model represents the physical transmission topology according to the 2018 Multiregional Modeling Working Group (MMWG) peak 2020 summer power flow case

- All network resources and generation is mapped to bus bars, which in turn are mapped to BAs

We implemented 2030 transmission upgrades according to best-available data from Advisory Board member utilities

Major interfaces and contingency constraints are included in the model, based on endogenous contingency analysis

- High-voltage transmission elements are monitored for violations in the model

In addition to physical transmission limits, we modeled typical available transfer capability (ATC) limits for non-firm, point-to-point transactions for available BA-to-BA contract paths in the region

- Carolina utilities' transfer limits are based on Advisory Board input
- Other utilities' limits are based on 90th percentile of 2019-2021 net transfer data from the EIA-930 filing
- Trading with areas external to the simulated region (e.g., MISO, SPP, NYISO) is modeled on fixed schedules, based on 2020 hourly net interchange reported in EIA-930 filing

Trading Frictions

Transactions are charged OATT rates, trading margins, and administrative fees

- Non-firm transmission service rates are based on the most recent data from OASIS
  - We assume PJM charges a discounted $0.67/MWh rate for non-firm point-to-point transmission service to its border. Source: PJM Manual 27, revision 96 (12/21/2022), Section 6.1.2
  - SEEM transactions use available non-firm transmission capacity and do not incur OATT charges
  - JDA transactions likewise do not incur OATT charges
- SEEM administrative charges are based on SEEM cost-recovery mechanism
  - 75% of $2.8 million/year operating costs recovered through per-MWh charges (source: SEEM Agreement), levelized over 1.3 GWh average hourly trading volume reported in Guidehouse's SEEM cost-benefit analysis

Trading Friction Assumptions

OATT Rates	On-Peak 2022$/MWh	Off-Peak 2022$/MWh
DUKE	$3.86	$1.84
SCEG	$14.17	$6.75
SC	$8.09	$3.84
SOCO	$10.17	$4.84
TVA	$6.06	$2.89
AECI	$3.00	$2.00
LGEE	$2.00	$2.00
PS	$4.00	$4.00
PJM	$0.67	$0.67
DEF	$11.73	$5.58
SEC	$6.12	$2.91
TECO	$6.39	$3.04
JEA	$3.84	$3.84
CPL	$3.86	$1.84

Other Trading Frictions Trade Type	Admin Fee 2022$/MWh	Margin 2022$/MWh
DA Bilateral (Non-RTO)	$ 1.00	$ 1.50
DA Bilateral (With RTO)	$ 1.00	$ 1.50
RT Bilateral (Non-RTO)	$ 1.00	$ 2.50
RT Bilateral (With RTO)	$ 1.00	$ 1.00
RTO-Internal	$ -	$ -
SEEM	$ 0.18	$ 0.91
JDA	$ 0.50	$ -

Note: Margins are per-participant (i.e. a trade would include a $3/MWh total trading margin friction component.

Market Reform Assumptions

Cycle	Status Quo	Carolinas JDA	EIM	Southeast RTO	Carolinas in PJM
Commitment					
DA	Utility-Specific	Utility-Specific	Utility-Specific	Pooled	Pooled
SEEM	Hold DA Commitment	Hold DA Commitment	-	-	-
RT	Utility-Specific Fast Start Commitment	Utility-Specific Fast Start Commitment	Pooled Fast Start Commitment	Pooled Fast Start Commitment	Pooled Fast Start Commitment
BA to BA Hurdles					
DA	OATT rate + $4 ED/$8 UC	OATT rate + $4 ED/$8 UC	OATT rate + $4 ED/$8 UC	No Hurdle	No Hurdle
SEEM	$2 hurdle	$2 hurdle	-	-	-
RT	OATT rate + $6 Non-RTO/$3 RTO Trades	$0.50 hurdle	No Hurdle	No Hurdle	No Hurdle
Transmission Capability					
DA	Based on Historical Usage	Based on Historical Usage	Based on Historical Usage	Physical Limits Only	Physical Limits Only
SEEM	Historical - DA trades	Historical - DA trades	-	-	-
RT	Historical - DA - SEEM	Historical - DA - SEEM	Physical Limits - DA Trades	Physical Limits Only	Physical Limits Only
Reserves					
	Utility-specific (w/ sharing groups)	Utility-specific (w/ sharing groups)	Utility-specific (w/ sharing groups, spin diversity benefit)	Market-wide sharing	Market-wide sharing
Look-Ahead (Hours)					
DA	48	48	48	48	48
SEEM	2	2	-	-	-
RT	2	2	2	2	2

2020 Benchmarking

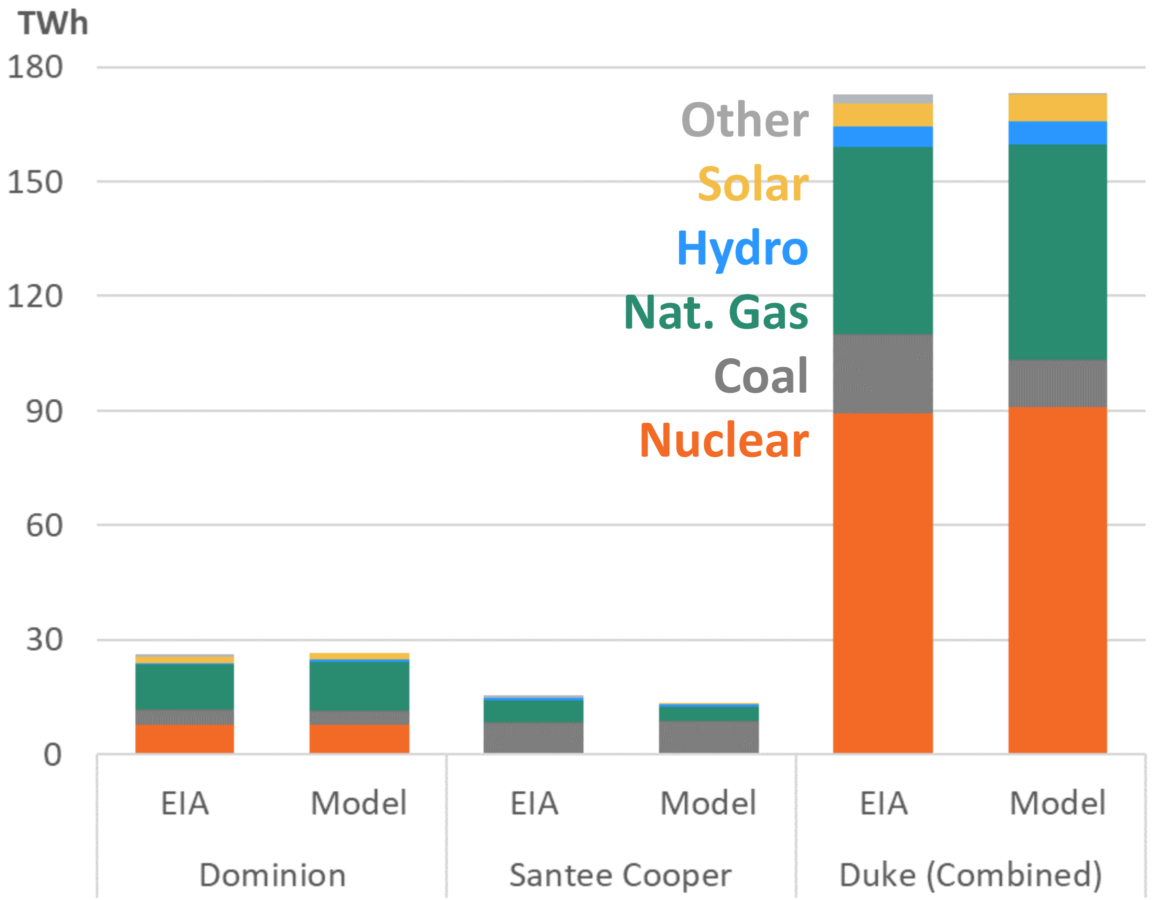
(Draft results as presented during December 19, 2022 Stakeholder meeting)

Carolina Generation Output by Resource Type

We benchmarked modeled generation against 2020 EIA Form 923 data

- Differences in total generation are due to trading
  - Santee Cooper imports slightly more
  - Duke exports slightly less
- SOCO coal is slightly cheaper and displaces Duke coal in the benchmark simulations (compared to actual generation)

Simulated 2020 Generation vs. Historical

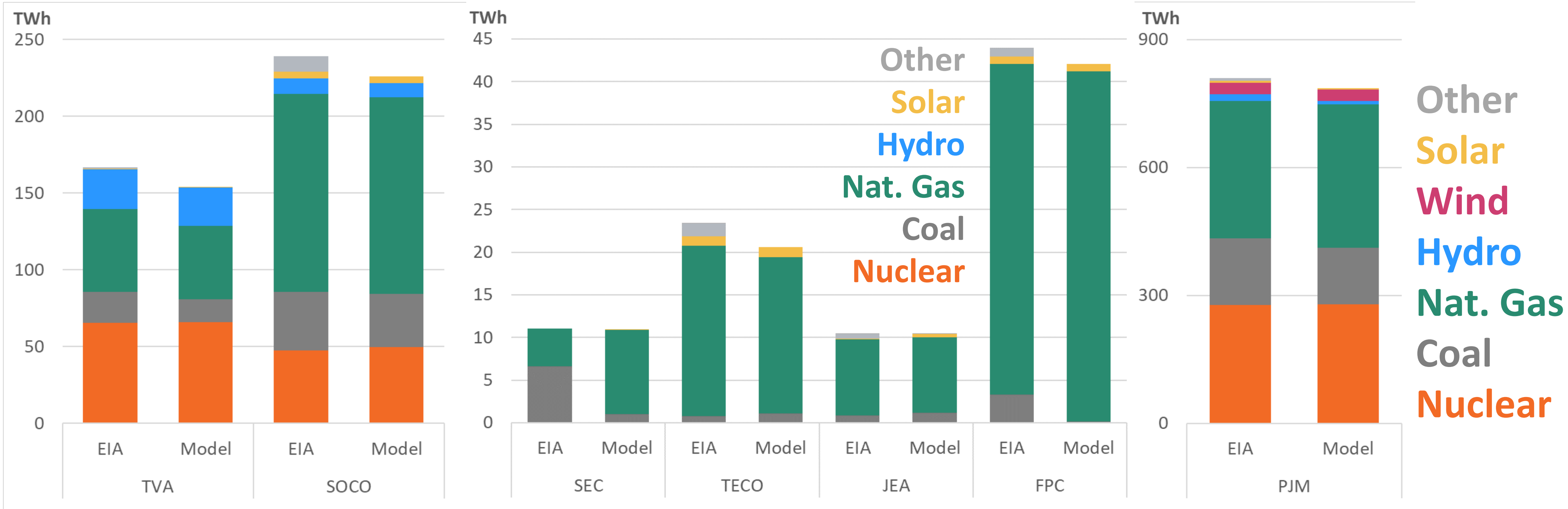


Note: Santee Cooper's stake in V. C. Summer nuclear plant is not represented out in this figure.

SERC and PJM Generation Output by Resource Type

Simulated generation output matches historical values well, with differences due to trading (including with regions outside the simulated footprint, such as MISO and SPP)

Modeled 2020 Generation Mix vs. Historical



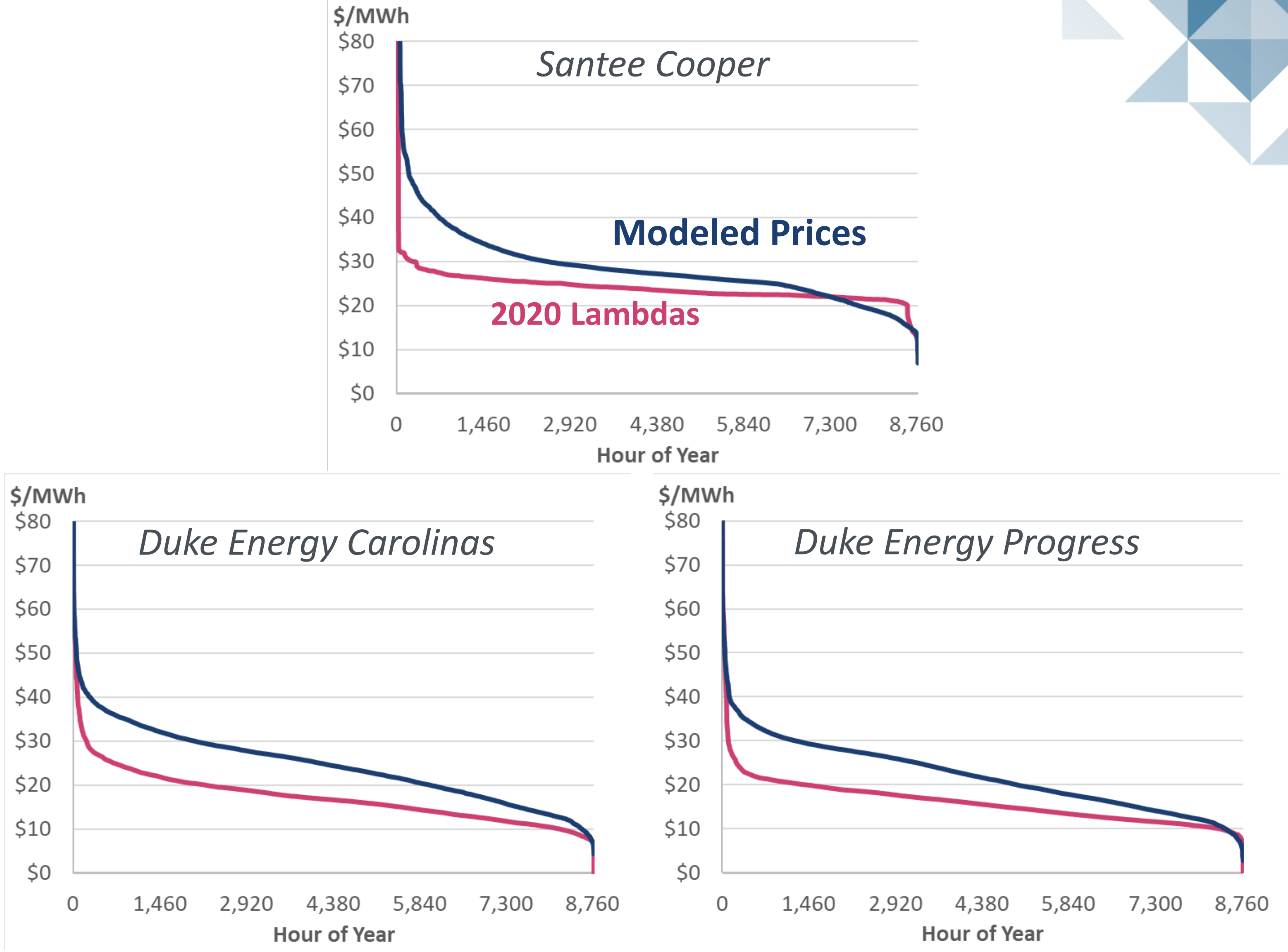
Carolina Energy Prices

We benchmarked modeled day-ahead load-weighted average LMPs against system lambdas from FERC 714 filings

Santee Cooper modeled prices are higher than 2020 lambdas because the utility's import constraints (modeled consistent with Advisory Panel input) forces it to rely on its own, higher-cost generation

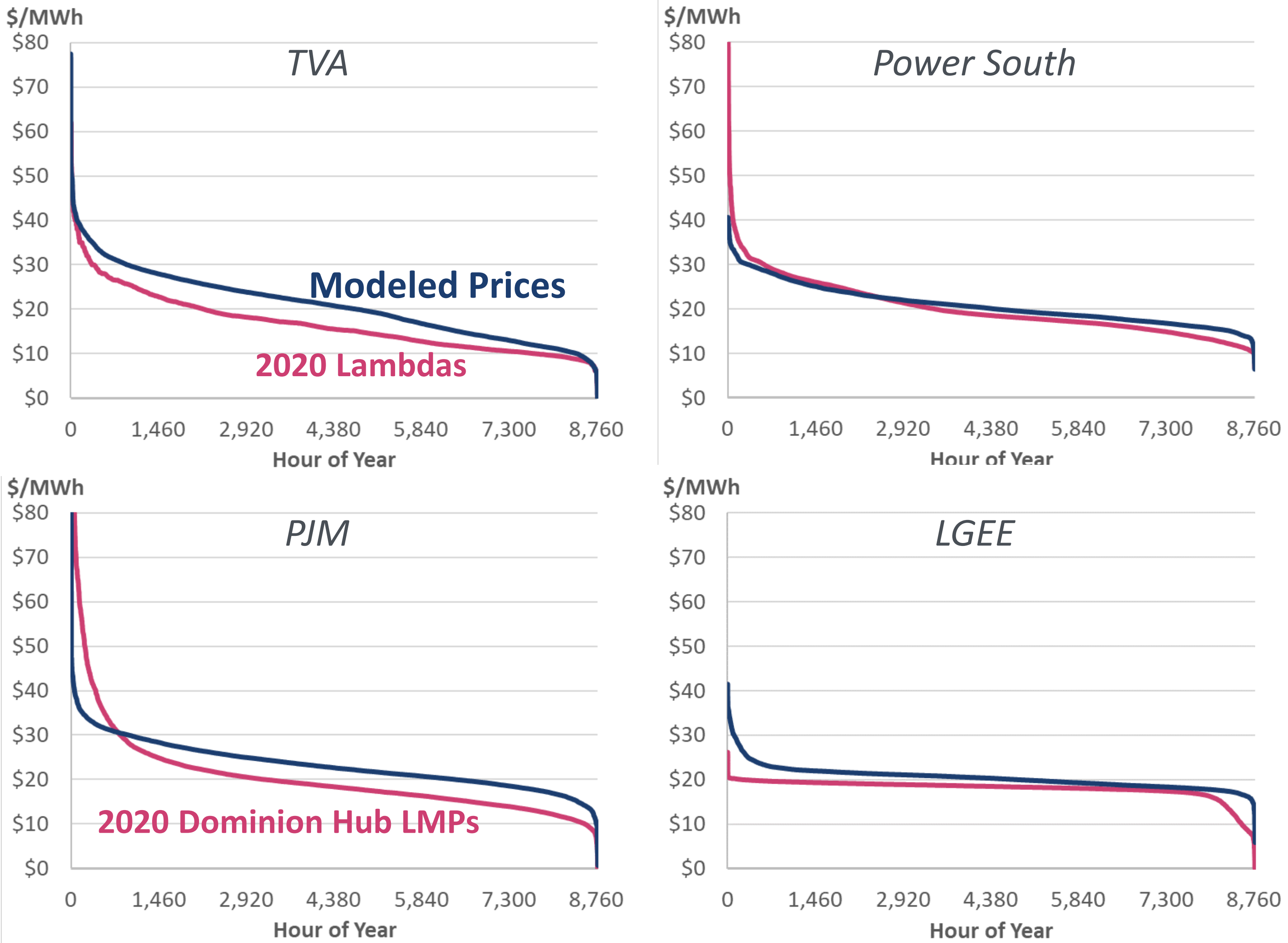
Some of the differences will be due to LMPs that (contrary to system lambdas) will reflect market interactions with neighboring systems

Modeled Prices vs. 2020 Lambdas



Energy Prices: SERC SEEM Members

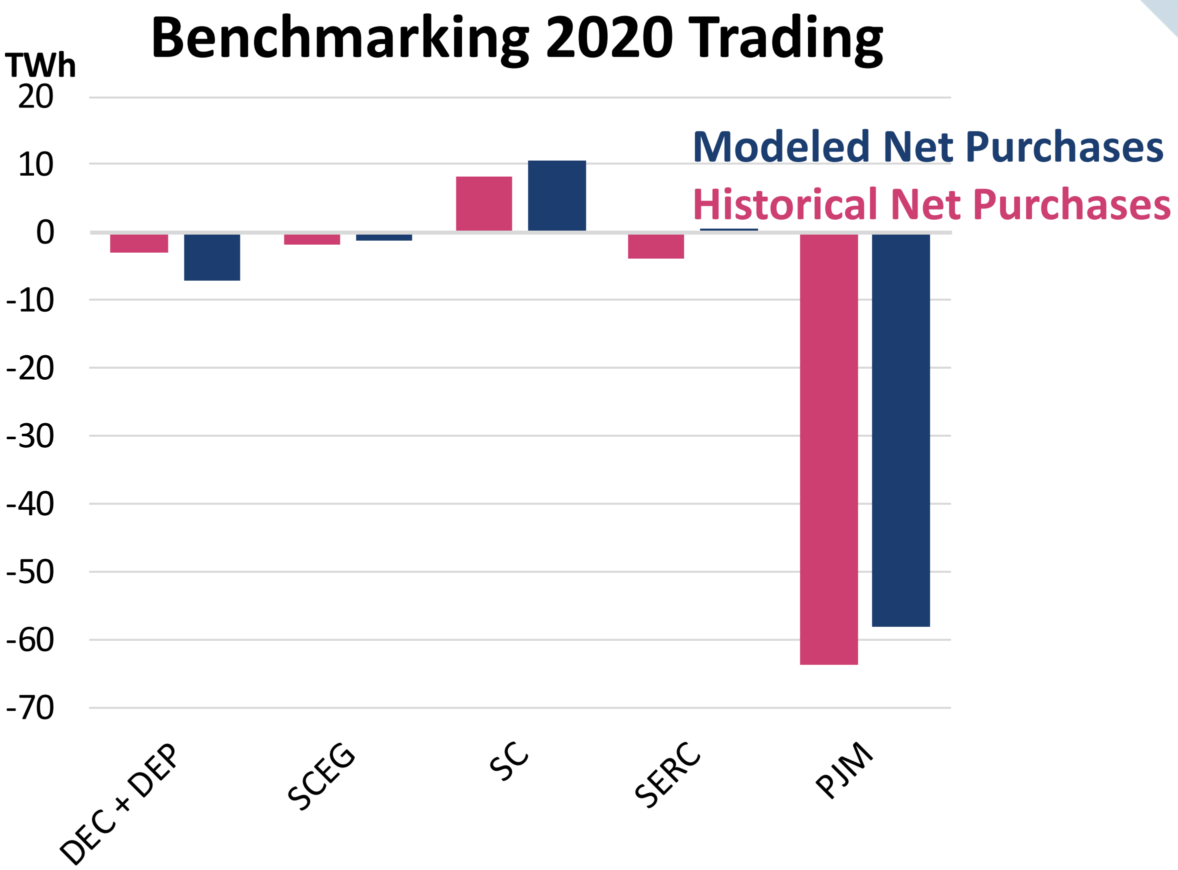
Modeled Prices vs. 2020 Lambdas



Simulated vs. Actual 2020 Trading

We benchmark modeled 2020 day-ahead trading against historical data

- Duke's modeled trades match historical values closely
- Santee Cooper imports more than historical
- TVA/SOCO discrepancies include effects from trades with MISO (not in the model footprint)
- PJM export volumes match historical well



Notes:
Positive values represent net imports, negative values are net exports.
Historical data represent total loads from EIA-930 filings minus total generation reported in EIA-923 filings.

Model Improvements Since 12/19 Stakeholder Meeting

We updated the benchmarking case with feedback received after the stakeholder meeting on 12/19/2022

- Duke and Santee Cooper provided confidential 2020 fuel price data which were not reflected in public data. These inputs lowered the cost of generation for both utilities
- Santee Cooper indicated that they had recallable (discounted) transmission rights with Southern Company in 2020. Implementing these lower fees shifted Santee Cooper trading activity to rely more on Southern for imports

Beyond stakeholder-specific input updates, we also made several improvements for the 2020 back-casting and the 2030 forward-looking study simulations:

- Adjusted generation startup costs to omit long-term maintenance costs that were included as “cycling” costs
- Refined the representation of network topology
- Finalized the generation resource mapping
- Refined modelling of hydro resources
- Updated outages schedules for some units based on public data

2030 Market Simulation Results

2030 Generation Results – Total for Carolina Utilities

By 2030, almost two-thirds of South Carolina generation will come from very low marginal cost resources like nuclear and renewables

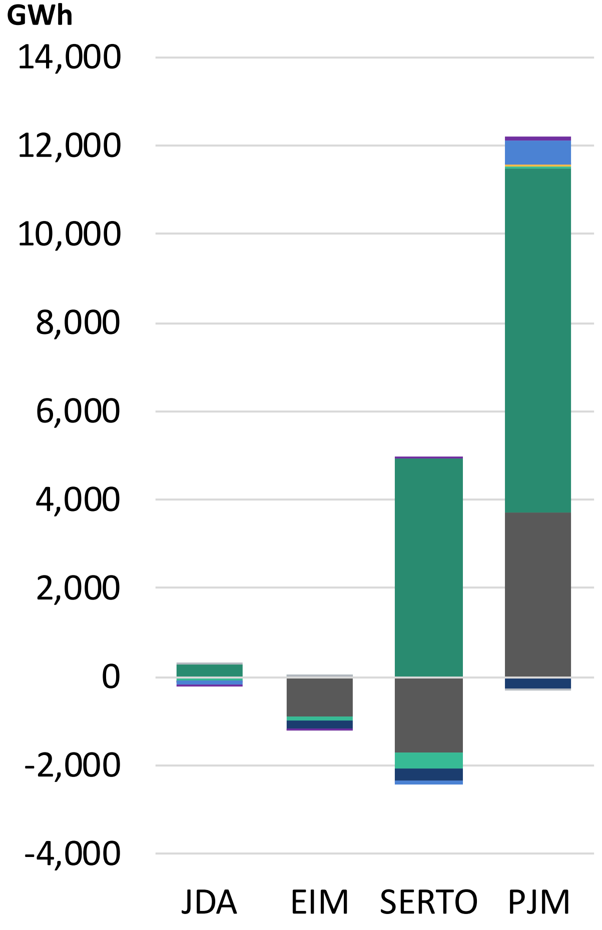
- Average cost of production will be around $15/MWh

The South Carolina utilities see minimal solar curtailments across market cases

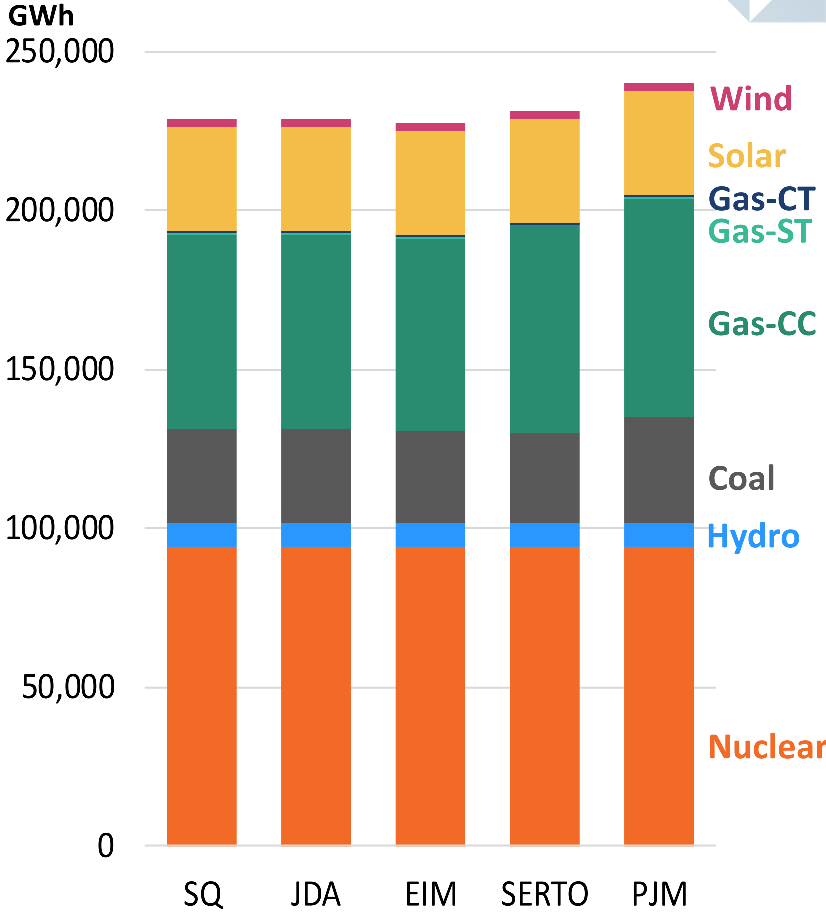
Market integration increases South Carolina thermal generation because it is cost-competitive with neighboring regions, especially PJM

- South Carolina coal is less competitive than gas resources in the Southeast
- Both coal and gas are cost-competitive in PJM
- Reduced pumped hydro storage activity (shows up as positive generation difference) in PJM because larger resource and load diversity reduce need for storage

Change in Carolina Generation by Case



Total North and South Carolina Generation

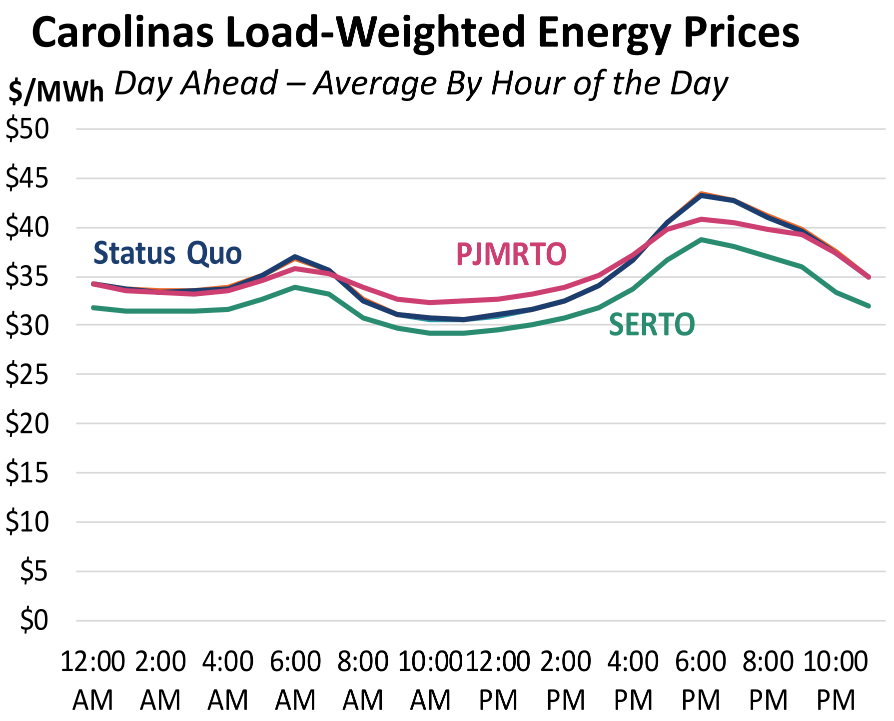


Note: Storage losses are minimal and are not shown.

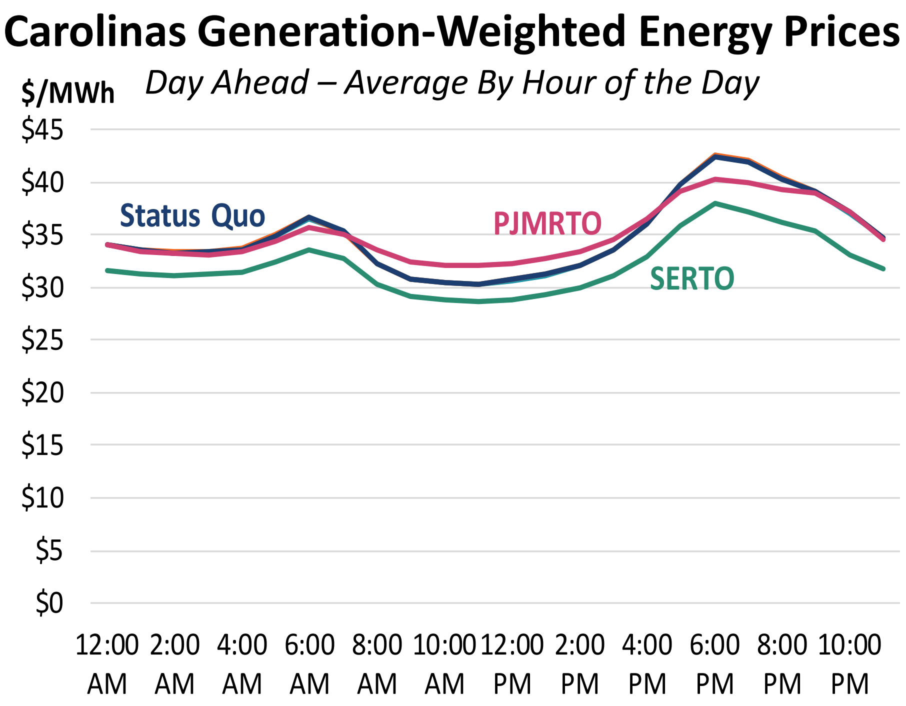
Simulated 2030 Wholesale Energy Market Prices

Average energy prices drop in the Southeast RTO for the Carolinas, but increase in the PJM RTO case

- The SERTO market allows the Carolinas to access inexpensive generation from other Southeast members, decreasing prices
- In the PJM market case, South Carolinas' energy prices equalize with the rest of the PJM market, remaining roughly similar, on average, as their status quo levels



Notes: Includes all of Duke, Santee Cooper, and Dominion SC



Notes: Includes all of Duke, Santee Cooper, and Dominion SC

2030 Trading Volumes – Total of Carolina Utilities

Increasing market integration allows greater trading, thanks to optimized dispatch and lower hurdle rates

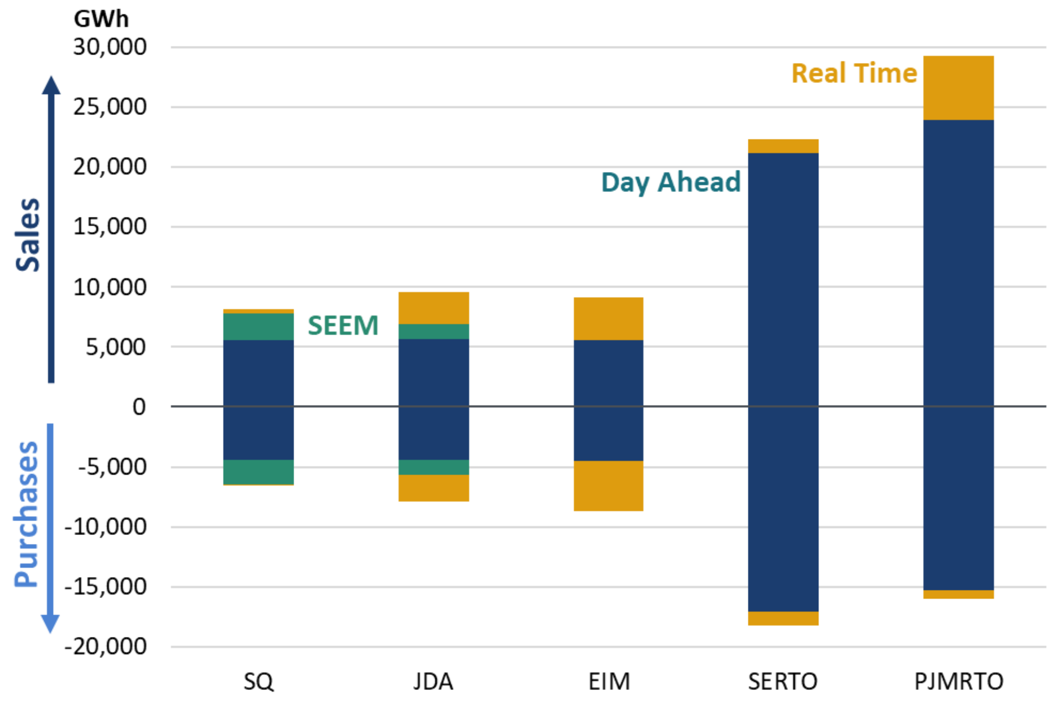
- SEEM trading accounts for just over 1% of total SEEM footprint demand in the Status Quo case, with minimal incremental transactions in real-time
- The Carolina utilities increase real-time trading volume under the JDA, and more so in the EIM

Joint commitment and day-ahead dispatch in the RTO cases enable significantly higher day-ahead trading than bilateral markets and utility-specific commitment

- Minor incremental real-time trading occurs to recover from forced generation outages
- Modeling forecast uncertainty would increase RTO real-time trading

South Carolina trades more in PJM than the SERTO because its generation is more cost-competitive in PJM

Carolina Utilities' Gross Trading by Case



SEEM Trading

Simulated SEEM trading volumes significantly exceed historically-observed SEEM trading volumes

- Simulated trading volumes are more than ten times larger than historically observed activity
- Actual volumes may grow through 2030 as members become comfortable with the platform

We calculate modeled SEEM trading volumes based on gross changes in balancing authority generation across the SEEM footprint between the day-ahead and SEEM optimization cycles

- For example, if Utility A generation in the SEEM optimization is 100 MWh lower than its generation in the day-ahead optimization, we count that utility as having purchased 100 MWh in the SEEM

Modeled vs. Historical SEEM Trading Volume

(Current SEEM members only, without new Florida joiners)

	Historical (2022-2023) *GWh*	Modeled (2030) *GWh*
November	23	474
December	40	508
January	47	588
February	36	420
March	38	435
Annual (Projected)	**481**	**5,818**

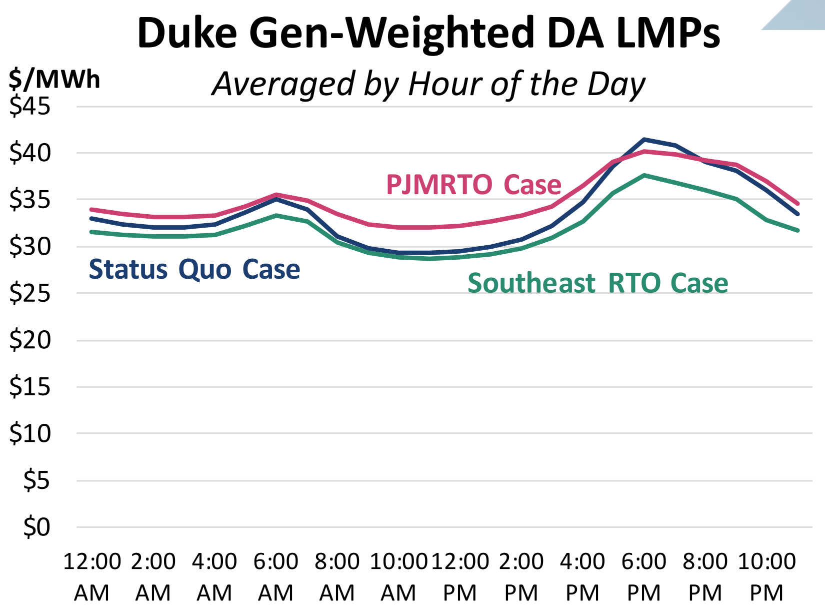
Additional Discussion of Duke Results

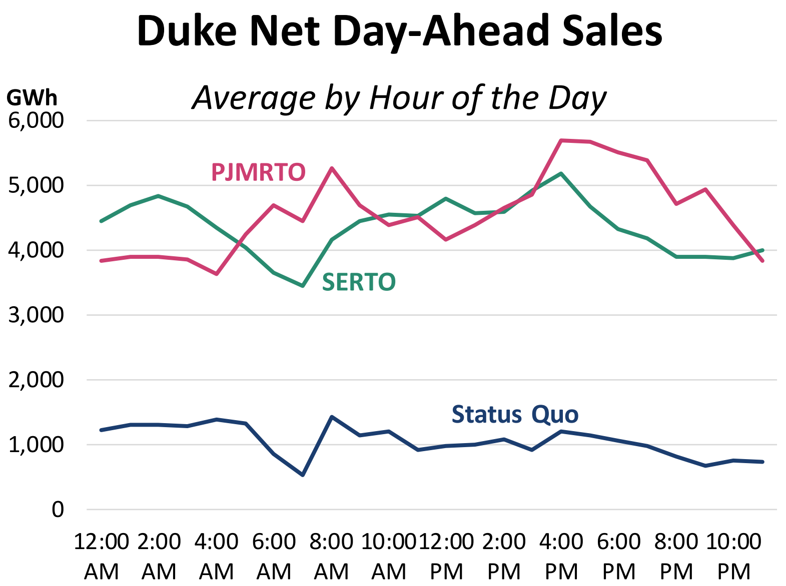
Our modeling shows Duke with a 2% increase in production costs in the SERTO case

- Prices vary among Southeastern BAs in the status quo
- Duke is a net exporter in the 2030 status quo case (and historically), with large profits on low-cost exports
- Without trading hurdles, Duke exports more in the RTO
- Duke earns lower profits on its exports because, due to significant solar and low-cost natural gas generation in the region, energy prices are equalized across the Southeast in SERTO (and lower than in the Status Quo and PJM cases)

Our modeling shows Duke as benefitting in the PJM case

- PJM energy prices are higher than Southeast prices
- Duke earns more in PJM market because its generation is cost-competitive, especially during high-priced evening hours
  - Evening trading is higher in PJM than the status quo thanks to the absence of trading frictions
- In PJM, Duke additionally profits by selling power to the Southeast, taking advantage of a lower export hurdle rate in PJM





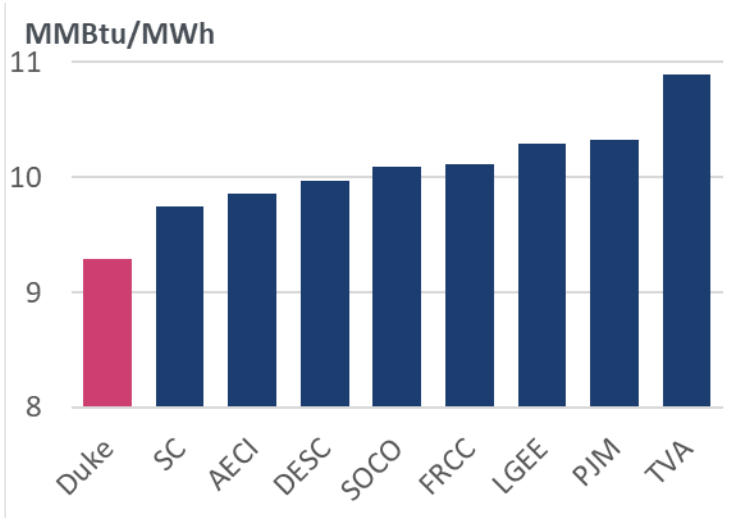
Duke Heat Rates and Coal Generation

Duke's increased exports stem from its coal and gas CC facilities, which are some of the most efficient plants in the region

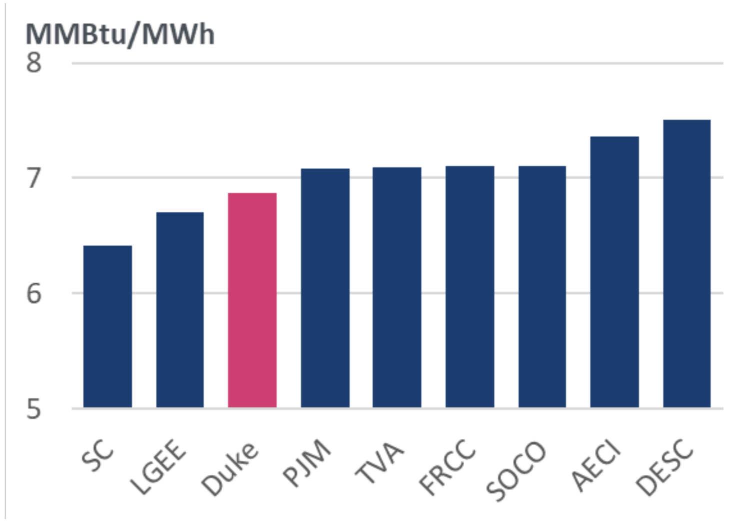
- Modeled heat rates are based on stakeholder and public data

Increases in Duke coal and gas generation enable decreases of coal generation in other balancing areas

Capacity-Weighted Average Coal Heat Rates



Capacity-Weighted Average Gas CC Heat Rates



Simulated 2030 Annual Coal Generation By Market Reform Case

	Annual Coal Generation					Increase (Decrease) Relative to SQ			
	SQ *TWh*	JDA *TWh*	EIM *TWh*	SERTO *TWh*	PJMRTO *TWh*	JDA *TWh*	EIM *TWh*	SERTO *TWh*	PJMRTO *TWh*
Duke	17.7	17.7	17.5	20.6	24.4	0.0	(0.1)	2.9	6.7
SC	6.7	6.8	6.7	3.5	3.3	0.0	0.0	(3.2)	(3.4)
DESC	4.7	4.7	4.7	3.7	3.6	0.0	(0.0)	(1.0)	(1.1)
Rest of SERC	72.2	72.4	72.2	76.4	71.8	0.2	(0.0)	4.1	(0.4)
FRCC	7.1	7.2	7.2	3.8	7.2	0.1	0.1	(3.4)	0.1
PJM	121.3	121.8	121.6	114.7	118.8	0.5	0.3	(6.5)	(2.5)
Total	**230**	**231**	**230**	**223**	**229**	**0.8**	**0.2**	**(7.1)**	**(0.7)**

Emissions Impacts of Market Reforms

More efficient generation under market-based optimal unit commitment and dispatch causes a redistribution of generation among market participants, reducing overall emissions

- Increases of more efficient Duke generation in the SERTO and PJMRTO cases increases emissions from Duke generation facilities, but reduces the dispatch of and emissions from less efficient generators in the regional footprint

Overall, market reforms result in lower emissions within the market footprint

Emissions by Market Reform Case

Area	Annual Emissions					Increase (Decrease) Relative to SQ			
	Base	**JDA**	**EIM**	**SERTO**	**PJM**	**JDA-SQ**	**EIM-SQ**	**SERTO-SQ**	**PJM-SQ**
	M Tons CO2	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*
Duke	34.4	34.6	34.3	40.5	43.2	0.2	(0.1)	6.2	8.9
SC	11.5	11.3	10.9	8.5	7.9	(0.2)	(0.6)	(3.0)	(3.6)
DESC	9.3	9.2	8.9	5.3	6.9	(0.0)	(0.4)	(4.0)	(2.4)
Rest of SERC	153.6	153.8	154.2	162.0	152.5	0.2	0.6	8.4	(1.1)
FRCC	85.8	85.9	86.9	78.4	85.8	0.1	1.0	(7.4)	(0.0)
PJM	286.4	286.6	286.2	278.6	279.0	0.2	(0.1)	(7.8)	(7.4)

Notes: FRCC includes both SEEM and non-SEEM entities. PJM includes the present-day PJM footprint, without the Carolinas.

Overall 2030 Benefits

Evaluated Benefit Metrics:

- **"Adjusted Production Cost" (APC):** The operating costs of all units + purchase costs (at load LMP) – sales revenues (at gen LMP)
- **Wheeling Revenues:** The losses in transmission wheeling revenues associated with some market options
- **Market Settlements and Bilateral Trading Gains:** The change in value of trading gains from market and non-market transmission
  - In bilateral transactions, the difference between importer load LMP and exporter generation LMP, less trading frictions, is the "value of the trade" and is allocated equally to both parties
  - In market transactions, BA-internal congestion value is assumed to be refunded to load-serving entities

Total 2030 Generation Operating Cost Savings of Different Wholesale Market Options

(Relative to Status Quo)

Entity	JDA	EIM	SERTO	PJMRTO
Duke (SC portions)	$ 1	$ 2	$ (9)	$ 44
Dominion SC	$ 7	$ 6	$ 64	$ 74
Santee Cooper	$ 3	$ 16	$ 42	$ 64
South Carolina	**$ 12**	**$ 24**	**$ 96**	**$ 181**
Total Regional Market	$ 15	$ 99	$ 228	$ 322

Source/Notes:
[1]: Operational cost savings include changes in "adjusted production costs" (fuel and variable generation costs and market purchase costs net of off-system sales revenues), transmission "wheeling" revenues, and gains from bilateral trades and market-based congestion revenues (in EIM and RTO cases), both for transaction within regional footprints and external to them.
[2]: The Duke row shows only South Carolina benefits (21% of total company benefits, allocated based on load share). Duke's costs increase slightly in the Southeast RTO case in large part due to the company realizing lower wholesale market prices on its off-system sales in a Southeast RTO, as discussed further below and in Appendix B.
[3]: Total regional market benefits based on the regional market footprint analyzed in the case.
Update load share and table numbers.

Overall Benefits (Detailed)

		Market Reform Results					Delta Above (Below) Status Quo (Negative is Benefit)							
Cost Component	Unit	2030 SQ	JDA	EIM	SERTO	PJM RTO	JDA		EIM		SERTO		PJM RTO	
SC Adjusted	**Mln $**	**$1,809**	**$1,803**	**$1,797**	**$1,700**	**$1,616**	**$ 5.72**	**0.3%**	**$ 12.46**	**0.7%**	**$ 108.85**	**6.0%**	**$ 192.52**	**10.6%**
Total Production Cost														
Duke	Mln $	$ 2,341	$ 2,352	$ 2,339	$ 2,757	$ 2,807	$ (10.96)	-0.5%	$ 1.67	0.1%	$ (416)	-18%	$ (467)	-20%
Dominion	Mln $	$ 525	$ 523	$ 507	$ 245	$ 369	$ 1.86	0.4%	$ 18	3.4%	$ 280	53%	$ 155	30%
Santee Cooper	Mln $	$ 626	$ 620	$ 602	$ 505	$ 463	$ 5.86	0.9%	$ 24	3.8%	$ 122	19%	$ 163	26%
Revenue and Quantity of Sales (Purchases)														
Duke	Mln $	$ 156	$ 208	$ 196	$ 610	$ 905	$ 52	33%	$ 40	26%	$ 454	292%	$ 749	481%
Duke	GWh	(171)	(7)	(6)	(19)	(25)	165	-96%	152	-89%	171	-100%	336	-196%
Dominion	Mln $	$ (97)	$ (125)	$ (140)	$ (338)	$ (205)	$ (27)	28%	$ (42)	43%	$ (240)	247%	$ (107)	110%
Dominion	GWh	(25)	3.2	3.7	10	6.2	28	-113%	36	-142%	25	-100%	53	-213%
Santee Cooper	Mln $	$ (68)	$ (78)	$ (90)	$ (155)	$ (173)	$ (10)	14%	$ (87)	128%	$ 68	-100%	$ 58	-86%
Santee Cooper	GWh	(29)	1.7	2.2	4.7	5.4	30	-106%	31	-108%	33	-116%	34	-119%
Total Adjusted Production Cost														
Duke	Mln $	$ 2,142	$ 2,144	$ 2,143	$ 2,147	$ 1,903	$ (2.3)	-0.1%	$ (1.7)	-0.1%	$ (5)	-0.3%	$ 239	11.2%
Dominion	Mln $	$ 648	$ 648	$ 646	$ 583	$ 574	$ 0.7	0.1%	$ 2.0	0.3%	$ 66	10%	$ 74	11.5%
Santee Cooper	Mln $	$ 704	$ 698	$ 693	$ 659	$ 637	$ 5.5	0.8%	$ 11	1.5%	$ 44	6.3%	$ 67	9.5%
Gains from Trade														
Duke	Mln $	$ 27	$ 32	$ 34	$ 4.3	$ 9	$ (5.3)	-19.9%	$ (7.3)	-27.1%	$ 23	84%	$ 17	65.3%
Dominion	Mln $	$ 5.9	$ 13	$ 10	$ -	$ 0.4	$ (6.8)	-115%	$ (4.3)	-73.3%	$ 6	100%	$ 5	92.7%
Santee Cooper	Mln $	$ 9	$ 6.9	$ 15	$ -	$ 1.6	$ 2.2	24.4%	$ (5.4)	-58.9%	$ 9	100%	$ 8	82.4%
Wheeling Revenues														
Duke	Mln $	$ 21	$ 22	$ 24	$ 17	$ 1.3	$ (0.75)	-3.5%	$ (3.0)	-14.1%	$ 4.8	23%	$ 20	93.7%
Dominion	Mln $	$ 0.1	$ 0.0	$ 0.0	$ -	$ 0.1	$ 0.01	13.3%	$ 0.01	11.4%	$ 0.06	100%	$ (0.06)	-99.7%
Santee Cooper	Mln $	$ 0.7	$ 0.7	$ 0.7	$ -	$ 0.4	$ 0.02	3.4%	$ 0.01	1.9%	$ 0.71	100%	$ 0.29	41.0%

How to Read "Adjusted Production Cost" Tables

The tables on the following slides compare production/trading volumes and average/total costs across scenarios

- **Panel 1** shows the total production and transaction volumes across each case and market type
- **Panel 2** shows the average cost of production, and the average cost of sales and purchases across all hours when a utility trades
- **Panel 3** shows the total cost or revenue credited to the utility or footprint
- Total production cost savings are the sum of utility costs and revenues. Costs are production cost and purchase costs (rows 1, 2, 3, 4, and 5). Revenues are rows 6, 7, 8, and 9. **Row 10, the total of adjusted production cost =[1] + [3 - 5] – [7 - 9]**

Example: Adjusted Production Cost for the Carolina Utilities – Southeast RTO Results

		Panel 1: Volumes			Panel 2: Prices			Panel 3: Dollars			
		GWh			$/MWh			Total ($1000s/Year)			Green = (+) in benefit Red = (-) in benefit
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference	
Production	[1]	226,876	229,417	2,542	$15.39	$15.29	-$0.10	3,491,679	3,506,761	$15,082	(Cost Increase)
Purchases	[2]										
Bilateral/Day-Ahead Market	[3]	4,450	17,041	12,591	$43.77	$32.71	-$11.06	194,793	557,463	$362,670	(Cost Increase)
SEEM Market	[4]	2,028	-	-2,028	$39.19	-	NA	79,459	-	-$79,459	(Cost Savings)
Real-Time Market	[5]	74	1,141	1,066	$55.67	$36.60	-$19.07	4,137	41,752	$37,615	
Sales	[6]										
Bilateral/Day-Ahead Market	[7]	5,543	21,116	15,572	$33.43	$31.93	-$1.50	185,328	674,194	$488,866	(Revenue Increase)
SEEM Market	[8]	2,228	-	-2,228	$33.78	-	NA	75,253	-	-$75,253	(Revenue Loss)
Real-Time Market	[9]	392	1,218	826	$40.54	$35.10	-$5.44	15,876	42,739	$26,863	
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.04**	**-$0.46**	3,493,610	3,389,043	-$104,567	(Absolute Benefit)
% Change in APC	[11]									*-3.0%*	(Relative Benefit)

Note: Per-MWh costs in row [1] represent average production costs. Purchase prices in rows [3]-[5] represent BA load-weighted LMPs averaged across all net purchase hours. Sales prices in rows [7]-[9] represent generation-weighted LMPs averaged across all net sales hours.

JDA Benefits

JDA vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$0.5	$0.2	$1.1	$0.8	0.2%
Santee Cooper	$5.5	$0.0	-$2.2	$3.3	0.5%
Dominion SC	$0.7	$0.0	$6.8	$7.4	1.1%
South Carolina	**$5.7**	**$0.1**	**$5.7**	**$11.5**	**0.6%**
Total Carolinas	$3.9	$0.7	$9.9	$14.5	0.4%
Total Regional Market	$3.9	$0.7	$9.9	$14.5	0.4%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	226,968	**93**	$15.39	$15.40	**$0.01**	3,491,679	3,494,920	**$3,241**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	4,431	**-19**	$43.77	$43.67	**-$0.10**	194,793	193,530	**-$1,263**
SEEM Market	[4]	2,028	3,227	**1,200**	$39.19	$37.23	**-$1.96**	79,459	120,155	**$40,697**
Real-Time Market	[5]	74	245	**171**	$55.67	$34.80	**-$20.87**	4,137	8,538	**$4,401**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	5,627	**84**	$33.43	$33.30	**-$0.13**	185,328	187,385	**$2,057**
SEEM Market	[8]	2,228	3,231	**1,003**	$33.78	$34.41	**$0.63**	75,253	111,183	**$35,930**
Real-Time Market	[9]	392	749	**358**	$40.54	$38.58	**-$1.96**	15,876	28,900	**$13,025**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.49**	**-$0.02**	3,493,610	3,489,674	**-$3,936**
% Change in APC	[11]									***-0.1%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

JDA Benefits

Adjusted Production Cost: Duke

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	177,789	178,102	**313**	$13.17	$13.20	**$0.04**	2,340,667	2,351,624	**$10,957**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	628	**25**	$42.71	$43.13	**$0.42**	25,752	27,098	**$1,347**
SEEM Market	[4]	825	879	**55**	$43.63	$43.00	**-$0.62**	35,976	37,811	**$1,835**
Real-Time Market	[5]	4	191	**187**	$49.90	$34.39	**-$15.51**	178	6,554	**$6,375**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	5,515	**81**	$33.41	$33.28	**-$0.13**	181,550	183,538	**$1,988**
SEEM Market	[8]	1,911	2,440	**529**	$33.37	$33.34	**-$0.03**	63,773	81,346	**$17,573**
Real-Time Market	[9]	385	355	**-30**	$40.61	$40.29	**-$0.33**	15,632	14,314	**-$1,318**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.50**	**$0.01**	2,141,618	2,143,888	**$2,270**
% Change in APC	[11]									***0.1%***

Adjusted Production Cost: Dominion

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	21,936	21,855	**-80**	$23.93	$23.93	**$0.00**	524,809	522,951	**-$1,858**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	2,343	**-18**	$41.35	$41.21	**-$0.14**	97,625	96,547	**-$1,078**
SEEM Market	[4]	886	1,169	**283**	$34.40	$34.33	**-$0.07**	30,478	40,127	**$9,649**
Real-Time Market	[5]	1	35	**34**	$61.80	$36.41	**-$25.39**	34	1,256	**$1,223**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	5	**-1**	$46.74	$48.34	**$1.59**	266	223	**-$43**
SEEM Market	[8]	99	150	**51**	$42.92	$43.88	**$0.95**	4,240	6,573	**$2,333**
Real-Time Market	[9]	0	169	**168**	$67.57	$37.62	**-$29.95**	18	6,349	**$6,330**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$25.83**	**-$0.03**	648,422	647,736	**-$685**
% Change in APC	[11]									***-0.1%***

Adjusted Production Cost: Santee Cooper

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	27,151	27,011	**-140**	$23.06	$22.97	**-$0.10**	626,202	620,345	**-$5,857**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	1,460	**-26**	$48.05	$47.86	**-$0.19**	71,416	69,884	**-$1,532**
SEEM Market	[4]	317	1,179	**862**	$41.00	$35.79	**-$5.21**	13,005	42,218	**$29,213**
Real-Time Market	[5]	70	20	**-50**	$55.92	$35.96	**-$19.96**	3,925	728	**-$3,197**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	107	**4**	$33.97	$33.82	**-$0.16**	3,512	3,624	**$112**
SEEM Market	[8]	217	641	**424**	$33.29	$36.28	**$2.99**	7,240	23,264	**$16,024**
Real-Time Market	[9]	6	225	**219**	$34.88	$36.59	**$1.71**	226	8,238	**$8,012**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$24.32**	**-$0.19**	703,570	698,050	**-$5,521**
% Change in APC	[11]									***-0.8%***

EIM Benefits

EIM vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$0.4	$0.6	$1.5	$1.8	0.4%
Santee Cooper	$10.9	$0.0	$5.4	$16.2	2.3%
Dominion SC	$2.0	$0.0	$4.3	$6.3	1.0%
South Carolina	**$12.5**	**$0.6**	**$11.2**	**$24.3**	**1.3%**
Total Carolinas	$11.2	$3.0	$17.0	$31.1	0.9%
Total Regional Market	$41.5	-$5.2	$62.3	$98.7	0.7%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	225,690	**-1,186**	$15.39	$15.28	**-$0.11**	3,491,679	3,448,439	**-$43,240**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	4,479	**29**	$43.77	$43.54	**-$0.23**	194,793	195,054	**$262**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	4,248	**4,174**	$55.67	$34.00	**-$21.67**	4,137	144,423	**$140,286**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	5,581	**38**	$33.43	$33.33	**-$0.10**	185,328	186,021	**$693**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	3,571	**3,179**	$40.54	$33.45	**-$7.09**	15,876	119,450	**$103,575**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.46**	**-$0.05**	3,493,610	3,482,445	**-$11,165**
% Change in APC	[11]									***-0.3%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

EIM Benefits

Adjusted Production Cost: Duke

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	177,789	177,760	**-29**	$13.17	$13.16	**-$0.01**	2,340,667	2,338,996	**-$1,671**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	624	**21**	$42.71	$43.05	**$0.34**	25,752	26,874	**$1,122**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	1,214	**1,210**	$49.90	$37.63	**-$12.27**	178	45,670	**$45,492**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	5,468	**34**	$33.41	$33.30	**-$0.10**	181,550	182,100	**$550**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	2,641	**2,256**	$40.61	$32.63	**-$7.98**	15,632	86,171	**$70,540**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.50**	**$0.01**	2,141,618	2,143,269	**$1,651**
% Change in APC	[11]									***0.1%***

Adjusted Production Cost: Dominion

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	21,936	21,391	**-544**	$23.93	$23.70	**-$0.23**	524,809	506,948	**-$17,861**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	2,376	**15**	$41.35	$41.45	**$0.11**	97,625	98,508	**$883**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	1,503	**1,502**	$61.80	$32.28	**-$29.52**	34	48,508	**$48,474**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	5	**-1**	$46.74	$45.47	**-$1.28**	266	228	**-$39**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	187	**187**	$67.57	$38.86	**-$28.71**	18	7,273	**$7,255**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$25.78**	**-$0.08**	648,422	646,464	**-$1,958**
% Change in APC	[11]									***-0.3%***

Adjusted Production Cost: Santee Cooper

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	27,151	26,539	**-613**	$23.06	$22.70	**-$0.36**	626,202	602,495	**-$23,708**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	1,479	**-7**	$48.05	$47.12	**-$0.94**	71,416	69,673	**-$1,743**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	1,532	**1,461**	$55.92	$32.81	**-$23.11**	3,925	50,244	**$46,320**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	109	**5**	$33.97	$34.03	**$0.06**	3,512	3,693	**$181**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	743	**737**	$34.88	$35.00	**$0.12**	226	26,006	**$25,780**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$24.14**	**-$0.38**	703,570	692,712	**-$10,858**
% Change in APC	[11]									***-1.5%***

Southeast RTO Benefits

SERTO vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$1.2	-$1.2	-$6.9	-$9.3	-2.0%
Santee Cooper	$44.3	$1.9	-$4.5	$41.7	5.8%
Dominion SC	$65.7	$2.2	-$4.0	$64.0	9.8%
South Carolina	**$108.9**	**$2.9**	**-$15.4**	**$96.4**	**5.3%**
Total Carolinas	$104.6	-$1.6	-$40.8	$62.2	1.8%
Total Regional Market	$371.4	$8.8	-$152.4	$227.8	1.5%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	229,417	**2,542**	$15.39	$15.29	**-$0.10**	3,491,679	3,506,761	**$15,082**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	17,041	**12,591**	$43.77	$32.71	**-$11.06**	194,793	557,463	**$362,670**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	1,141	**1,066**	$55.67	$36.60	**-$19.07**	4,137	41,752	**$37,615**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	21,116	**15,572**	$33.43	$31.93	**-$1.50**	185,328	674,194	**$488,866**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	1,218	**826**	$40.54	$35.10	**-$5.44**	15,876	42,739	**$26,863**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.04**	**-$0.46**	3,493,610	3,389,043	**-$104,567**
% Change in APC	[11]									*-3.0%*

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

SERTO Benefits

Adjusted Production Cost: Duke

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	177,789	190,777	**12,988**	$13.17	$14.45	**$1.29**	2,340,667	2,757,133	**$416,466**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	1,286	**683**	$42.71	$34.39	**-$8.32**	25,752	44,219	**$18,467**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	889	**886**	$49.90	$36.82	**-$13.08**	178	32,744	**$32,565**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	20,646	**15,212**	$33.41	$31.92	**-$1.49**	181,550	658,997	**$477,447**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	816	**431**	$40.61	$34.35	**-$6.27**	15,632	28,034	**$12,402**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.52**	**$0.03**	2,141,618	2,147,064	**$5,446**
% Change in APC	[11]									***0.3%***

Adjusted Production Cost: Dominion

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	21,936	14,626	**-7,309**	$23.93	$16.75	**-$7.18**	524,809	244,950	**-$279,859**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	10,627	**8,266**	$41.35	$32.35	**-$9.00**	97,625	343,804	**$246,179**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	84	**84**	$61.80	$33.64	**-$28.16**	34	2,840	**$2,806**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	79	**73**	$46.74	$27.22	**-$19.53**	266	2,153	**$1,886**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	181	**180**	$67.57	$37.40	**-$30.17**	18	6,759	**$6,741**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$23.23**	**-$2.62**	648,422	582,682	**-$65,740**
% Change in APC	[11]									***-10.1%***

Adjusted Production Cost: Santee Cooper

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	27,151	24,014	**-3,137**	$23.06	$21.02	**-$2.05**	626,202	504,678	**-$121,524**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	5,128	**3,641**	$48.05	$33.04	**-$15.01**	71,416	169,440	**$98,024**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	167	**97**	$55.92	$36.93	**-$18.99**	3,925	6,168	**$2,244**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	391	**287**	$33.97	$33.40	**-$0.57**	3,512	13,044	**$9,532**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	221	**214**	$34.88	$35.99	**$1.11**	226	7,945	**$7,720**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$22.97**	**-$1.54**	703,570	659,297	**-$44,274**
% Change in APC	[11]									***-6.3%***

PJM Benefits of Market Participation by Carolina Utilities

PJM vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	$51.0	-$4.5	-$2.3	$44.2	9.7%
Santee Cooper	$67.1	-$0.6	-$2.9	$63.5	9.0%
Dominion SC	$74.5	$0.0	-$0.8	$73.7	11.4%
South Carolina	**$192.5**	**-$5.1**	**-$5.9**	**$181.5**	**10.0%**
Total Carolinas	$380.4	-$21.6	-$14.3	$344.5	9.9%
Total Regional Market	$367.8	-$20.6	-$25.6	$321.6	1.8%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	238,809	**11,934**	$15.39	$15.24	**-$0.15**	3,491,679	3,640,001	**$148,323**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	15,274	**10,823**	$43.77	$33.87	**-$9.90**	194,793	517,290	**$322,497**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	715	**641**	$55.67	$38.78	**-$16.90**	4,137	27,730	**$23,593**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	24,157	**18,614**	$33.43	$36.07	**$2.64**	185,328	871,445	**$686,117**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	5,376	**4,984**	$40.54	$37.28	**-$3.26**	15,876	200,382	**$184,506**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$13.82**	**-$1.69**	3,493,610	3,113,194	**-$380,416**
% Change in APC	[11]									***-10.9%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

PJM Benefits

Adjusted Production Cost: Duke

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	177,789	196,616	**18,827**	$13.17	$14.28	**$1.11**	2,340,667	2,807,251	**$466,584**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	1,430	**827**	$42.71	$35.25	**-$7.46**	25,752	50,408	**$24,656**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	501	**497**	$49.90	$39.44	**-$10.46**	178	19,755	**$19,577**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	23,665	**18,231**	$33.41	$35.98	**$2.57**	181,550	851,391	**$669,841**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	3,392	**3,007**	$40.61	$36.34	**-$4.28**	15,632	123,272	**$107,640**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$11.10**	**-$1.39**	2,141,618	1,902,751	**-$238,867**
% Change in APC	[11]									***-11.2%***

Adjusted Production Cost: Dominion

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	21,936	18,866	**-3,069**	$23.93	$19.58	**-$4.35**	524,809	369,339	**-$155,470**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	7,427	**5,066**	$41.35	$33.83	**-$7.51**	97,625	251,259	**$153,634**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	94	**94**	$61.80	$36.28	**-$25.52**	34	3,415	**$3,381**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	226	**220**	$46.74	$39.00	**-$7.75**	266	8,799	**$8,533**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	1,083	**1,083**	$67.57	$38.13	**-$29.43**	18	41,291	**$41,273**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$22.89**	**-$2.97**	648,422	573,923	**-$74,499**
% Change in APC	[11]									***-11.5%***

Adjusted Production Cost: Santee Cooper

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	27,151	23,327	**-3,824**	$23.06	$19.87	**-$3.20**	626,202	463,411	**-$162,792**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	6,417	**4,931**	$48.05	$33.60	**-$14.45**	71,416	215,623	**$144,207**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	120	**50**	$55.92	$37.96	**-$17.96**	3,925	4,560	**$636**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	266	**163**	$33.97	$42.23	**$8.26**	3,512	11,255	**$7,743**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	901	**894**	$34.88	$39.77	**$4.89**	226	35,820	**$35,594**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$22.18**	**-$2.34**	703,570	636,520	**-$67,050**
% Change in APC	[11]									***-9.5%***

The Brattle Group: Offices

Brattle Group Practices and Industries

ENERGY & UTILITIES

Competition & Market Manipulation
Distributed Energy Resources
Electric Transmission
Electricity Market Modeling & Resource Planning
Electrification & Growth Opportunities
Energy Litigation
Energy Storage
Environmental Policy, Planning and Compliance
Finance and Ratemaking
Gas/Electric Coordination
Market Design
Natural Gas & Petroleum
Nuclear
Renewable & Alternative Energy

LITIGATION

Accounting
Analysis of Market Manipulation
Antitrust/Competition
Bankruptcy & Restructuring
Big Data & Document Analytics
Commercial Damages
Environmental Litigation & Regulation
Intellectual Property
International Arbitration
International Trade
Labor & Employment
Mergers & Acquisitions Litigation
Product Liability
Securities & Finance
Tax Controversy & Transfer Pricing
Valuation
White Collar Investigations & Litigation

INDUSTRIES

Electric Power
Financial Institutions
Infrastructure
Natural Gas & Petroleum
Pharmaceuticals & Medical Devices
Telecommunications, Internet, and Media
Transportation
Water

Appendix D: Stakeholder Engagement Process

Our engagement with the Study Committee included the following:

- The Study Committee provided direction and approval of the study scope
- We provided educational workshops with the Study Committee on the implication of different market reform options
- Our team connected the Study Committee with practitioners in the industry to speak about their experience with market reforms.
- Our team served as an intermediary between the Study Committee and the Advisory Board; we collected written input from the Advisory Board and provided the Study Committee with a summary of that information. The Advisory Board members each had the opportunity to speak in front of the Study Committee.
- We provided the Study Committee with the Draft Report for review and comment.

Our engagement with the Advisory Board included the following:

- We conducted one-on-one interviews with each member of the Advisory Board to record their views on market reform and understand their hopes/priorities for the study.
- Brattle and several members of the Advisory Board (Duke, DESC, Santee Cooper, Central Elec Coop, and Piedmont Municipal Power Association (PMPA)) signed an NDA to share data from the signees with Brattle to inform our modeling effort.
- Our team conducted regular update meetings with the Advisory Board to discuss the market reform options we analyzed, our study approach and methodologies, the benefit and cost metrics analyzed, and potential draft recommendations.
- The Advisory Board was provided the draft results of the modeling effort and was given the opportunity to review draft results and provide comments.
- The Advisory Board was provided the Draft Report, including the recommendations on market reform options and was given the opportunity to review the draft and provide comments.
- Brattle responded to Advisory Board comments on the Draft Report in a live meeting and responded to all written comments in a separate document submitted to the Study Committee.

The full list of all meeting materials are available at the Electricity Market Reform Measures Study Committee website and a list of Study Committee and Advisory Board meetings is provided below.

Study Committee Meetings:

Presenter	Date
Study Committee	June 21, 2021
The Brattle Group	September 30, 2021
The Brattle Group	March 9, 2022
The Brattle Group	March 23, 2022
The Brattle Group	April 21, 2022
The Brattle Group	May 10, 2022
The Brattle Group	June 28, 2022
The Brattle Group, Advisory Board	July 13, 2022
Noel Black, VP Federal Regulatory Affairs, Southern Company	September 1, 2022
Commissioner Ted Thomas, Arkansas Public Service Commission	
Bruce Rew, SVP Operations, Southwest Power Pool	
The Brattle Group	

Advisory Board Meetings:

Presenter	Date
The Brattle Group	June 28, 2022
The Brattle Group	July 13, 2022
The Brattle Group	July 27, 2022
The Brattle Group	September 26, 2022
The Brattle Group	November 17, 2022
The Brattle Group	December 19, 2022
The Brattle Group	March 14, 2023

Listed in the order specified in Act 187, the members of the advisory board are:

Nanette S. Edwards	Executive Director	Office of Regulatory Staff
Patrick Cobb	Associate State Director at AARP	Federal Advocacy/Strategic Communications
Nelson Peeler	Senior Vice President and Chief Transmission Officer	Duke Energy
Marty Watson	Chief Power Supply Officer	Santee Cooper
Pandelis (Lee) Xanthakos	Director Electric Transmission	Dominion Energy
Sue Berkowitz Esq.	Director	SC Appleseed Justice League Center
Margaret Small		
Steve Chriss	Director, Energy Services	Walmart
Jennifer Burton	Senior Energy Manager	Lowe's Companies Inc.
Dennis Boyd	Electrical Power Engineer	Nucor Steel
Jamey Goldin	Energy Regulatory Counsel	Google
Eddy Moore	Energy Senior Program Director	Coastal Conservation League
Hamilton Davis	VP Markets and Regulatory Affairs	Southern Current LLC
Thomas L. Rhodes III	President	Rhodes Graduation Service
John Frick	VP Government Relations	The Electric Cooperatives of South Carolina Inc. (ECSC)
Jimmy Bagley	Deputy City Manager	Rockhill, SC
Joel Ledbetter	General Manager	Easley Combined Utilities
Stephen "Steve" Thomas	Senior Manager, Energy Contracts	Domtar
Amy Kurt	Director of Development, Eastern Region & Canada	EDP Renewables (EDPR)
Tyson Grinstead	Director of Public Policy	Sunrun
Mark Svrcek	Chief Operating Officer & Sr. VP of Corporate Strategy	Central Electric Power Cooperative Inc.
Bryan Stone	President	Lockhart Power Company
Neal Baxley	Owner	Baxley Farms, LLC

EXHIBIT ACL-9

Western Energy Imbalance Service and

SPP Western RTO Participation Benefits

Western Energy Imbalance Service and SPP Western RTO Participation Benefits

PREPARED BY

John Tsoukalis
Johannes Pfeifenberger
Metin Celebi
Sophie Leamon
Carson Peacock
Sharan Ganjam

PREPARED FOR

Southwest Power Pool

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Brattle

SPP Southwest Power Pool

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Executive Summary

This study estimates the production cost benefits that would likely result from the creation of the WEIS Market and from extending the full Southwest Power Pool (SPP) Regional Transmission Organization (RTO) market to include the WEIS footprint. To assess these benefits, the Brattle team created a unified nodal production cost model of the WECC and most of the Eastern Interconnection, connecting the two models across the seven DC ties. The integrated Western Electricity Coordinating Council (WECC) and Eastern Interconnection model was developed in the Power System Optimizer (PSO) production cost simulation software. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and Independent System Operator (ISO) market operations. PSO can generate hourly prices at every bus and generation output for each unit, which allow us to estimate changes in generation output, fuel use, production cost, or other metrics on a unit, state, utility, or regional level.

PSO is designed to mimic RTO and ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (e.g., load, fuel prices, etc.) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which would occur at different points in time and with different amounts of information about system conditions. PSO can simulate initial cycles to optimize unit commitment, calculate losses, and do an initial optimization of unit dispatch. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the market design of real-time energy imbalance markets. As part of this cycle-based structure, PSO can also consider forecasting uncertainty and intra-hour real-time operations, although at this point this functionality has not been utilized in our analysis of WEIS and full SPP market benefits. Simulation of uncertainty and intra-hour operational challenges would further increase the magnitude of estimated market benefits.

We started with developing two separate models: a WECC model and a separate Eastern Interconnection model. These models were then connected across the seven existing DC ties. The WECC model reflects the 2028 WECC System Stability Planning Anchor Data Set (ADS), which was developed by WECC staff to operate for the GridView production cost simulation software. We converted the ADS model from GridView to operate in the PSO software, making the model compatible with our Eastern Interconnection model, which was developed from a database created by the Newton Energy Group (NEG), the company that licenses the PSO software. The NEG model includes SPP, Midcontinent ISO (MISO), and the neighboring areas, and was built using publically available data from FERC filings on the transmission topology, the generation resources, and load in these regions. We altered the NEG model to be consistent with the WECC ADS assumptions and updated the transmission topology to include additional transmission constraints identified in SPP's 2020 ITP. In our WECC model, the initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, bilateral trading of power in the WECC, and a real-time economic dispatch cycle, reflecting the CAISO-administered Western Energy Imbalance Market (EIM) and the WEIS as they will be operated in the WECC by 2028.

The combined model of the WECC and Eastern Interconnection contains three cycles to simulate unit commitment and dispatch decisions along different timeframes and within different market structures. The model utilizes a day-ahead unit commitment cycle, in which the model optimizes unit commitment decisions for long lead-time resources based on the relative economics, operating characteristics and transmission constraints, and a day-ahead economic dispatch cycle, in which the model determines the optimal level of dispatch for all resources based on their relative economics subject to transmission constraints. The simulations then utilize a real-time cycle, in which the model re-optimizes unit commitment of fast-start resources (if market rules allow for it) and the dispatch of all committed resources. This real-time cycle also simulates the operation of imbalance markets, such as the EIM and WEIS.

To assess the benefits of participation in the WEIS Market and of extending the full SPP RTO market to the WEIS footprint, we simulated and compared three cases: (1) a Status Quo Case, (2) a WEIS Case, and (3) an RTO Case.

The **Status Quo Case** simulates operation of the Eastern Interconnection and WECC, including all the existing market structures with current and planned members in both interconnections. This includes the SPP, MISO, and CAISO RTO/ISO markets, and the CAISO-administered EIM. In the WEIS footprint, and in other non-market areas represented in the model, hurdle rates were applied between utilities to simulate bilateral trading frictions in all three cycles of the model. In the Status Quo Case, DC ties follow 2019 historical hourly flows in all cycles (shifted to align peak and off peak periods in 2028). Transmission capacity of WECC paths in the non-RTO areas of the WECC are derated by 10% to approximate the inefficiency with which bilateral contract-path transactions utilize the existing grid.

The **WEIS Case** is the same as the Status Quo Case, except that we implemented the proposed WEIS Market structure and allow for coordinated real-time trading over the four DC ties in the WEIS footprint. Hurdle rates between WEIS members are removed in the real-time cycle for transfers between WEIS members, and on flows over the four DC ties located within the WEIS footprint. The WECC path ratings in the WEIS footprint are returned to their full transmission capability (i.e., 10% derate is removed) in recognition that the WEIS Market is able to fully utilize the available grid capacity for real-time transactions.

The **RTO Case** simulates SPP's RTO market structure in the WEIS footprint. Hurdle rates are removed between the proposed WEIS member areas and the existing SPP market region in all cycles of the model, which implies day-ahead and real-time unit commitment and dispatch are optimized across the entire market footprint. Flows over the four DC ties that connect SPP to the WEIS are optimized in every cycle, and the WECC path ratings in the WEIS footprint are returned to their full transmission capability (i.e., 10% derate is removed) in recognition that nodal RTO markets are able to fully utilize the available grid capacity. We model a unified transmission tariff in the RTO Case across the SPP and the WEIS, implying that no hurdles exist in any cycle between WEIS participants and the current SPP footprint. The unified tariff implies a single regional through-and-out rate (RTOR) for sales from the WEIS footprint to other parts of the WECC, calculated as the average of the current wheeling rates for the WEIS members.

The study utilizes the Adjusted Production Cost (APC) metric, a simplified metric to estimate the cost of serving load for a utility or a group of utilities. In this study, the APC metric was calculated separately for the aggregate WEIS footprint and the SPP footprint. The APC metric allows us to estimate the production cost savings that the WEIS and SPP members would experience in the two market participation scenarios simulated in the study. The APC metric is calculated for each case, and the comparison across cases provides an estimate of how much the cost to serve load changes due to market participation. In the RTO Case, we also estimate the additional wheeling revenues that would be generated for the WEIS entities due to participation in the expanded SPP RTO.

We find that the creation of the WEIS is estimated to reduce APC by $16.1 million/year (0.3% of total APC) in the combined SPP and WEIS footprint. Of this benefit, $9 million/year (4.1% of APC) accrue to WEIS members and $7.1 million/year accrue to current SPP members (0.14% of APC). The production cost benefits experienced in the WEIS Market are due to the increased flows of low-cost power from SPP over the DC ties into the WEIS footprint. To accommodate this low-cost power, the WEIS members reduce production from higher-cost resources. This creates a benefit for SPP members, who are able to make more sales across the DC ties and for WEIS members that are able to substitute high-cost production for lower-cost purchases from SPP.

FIGURE 1: SUMMARY OF ESTIMATED MARKET PARTICIPATION BENEFITS ($ '000/YEAR)

Region	Reduction in APC	Wheeling Revenue	Total Benefit
WEIS Case	**-$16,174**		**$16,174**
WEIS Footprint	-$9,030		$9,030
SPP Footprint	-$7,144		$7,144
RTO Case	**-$32,648**		**$49,335**
WEIS Footprint	-$8,460	$16,687	$25,148
SPP Footprint	-$24,187		$24,187

We find that the extension of the SPP RTO to the WEIS footprint reduces APC for the study footprint by $33 million/year (0.6% of APC) and generates over $16 million/year of additional wheeling revenues; creating a total of over $49 million/year of benefits for the WEIS members and SPP. The WEIS members experience a reduction in APC of $8.5 million/year (3.9% of APC) and receive the $16 million/year of additional wheeling revenues. The current SPP members experience a reduction in APC of $24.2 million/year (1.3% of APC). The reduction in APC experienced in the RTO Case is primarily driven by an increase in market sales, which are mostly sold off-system to neighboring entities in the WECC. The expanded RTO market footprint allows entities in SPP to sell power into Arizona, New Mexico, Utah, and other areas of the WECC while only paying a single wheeling fee, which creates opportunity for increased market sales.

I. Scope of the Study

The Brattle Group was engaged by the SPP to develop an integrated model of the WECC and SPP footprints, and the areas neighboring SPP in the Eastern Interconnection. The objective of the study is to estimate the production cost benefits due to the creation of the Western Energy Imbalance Service (WEIS) Market and of extending the full SPP RTO market to the WEIS footprint. This analysis involved creating a unified nodal production cost model of the WECC and the Eastern Interconnection, and connecting the two models across the seven DC ties that bridge the two interconnections.

The Brattle team developed an integrated model of SPP and the WECC in the Power System Optimizer (PSO) production cost simulation software. The WECC portion of the model developed for this study is based on the 2028 WECC System Stability Planning Anchor Data Set (ADS), a model available to WECC members. The Eastern Interconnection portion of the model was developed based on a model of SPP, MISO, and neighboring areas licensed from the creators of PSO, the Newton Energy Group (NEG). The Brattle Group communicated with SPP and WEIS members (WAPA, Basin Electric Cooperative, and Tri-State Generation and Transmission Cooperative) to update the modeling assumptions to reflect the latest forecasts and projection for 2028 of generation resources, transmission, fuel prices and load into the model.

To assess the production cost benefits of the WEIS Market and the extension of the SPP RTO to the WEIS footprint, the Brattle team simulated three cases: a Status Quo Case, a WEIS Case, and an RTO Case. The Status Quo Case simulates operation of the Eastern Interconnection and WECC with the current market structures with current members (including members planning to join the EIM by 2028). The WEIS Case is the same as the Status Quo Case except that we implement the proposed WEIS Market structure coupled with coordinated real-time imbalance transactions between the WEIS members and the SPP members across the four DC ties in the WEIS footprint. The WEIS Market structure is implemented for the planned members in the WECC, and allows the model to coordinate real-time imbalance transactions between WEIS members and SPP members through optimal dispatch in the real-time, but without day-ahead optimization across the WEIS-SPP footprint. In the RTO Case, we implement an RTO market spanning the combined region of the prospective WEIS member areas and SPP.

The benefits estimated in this study center around the Adjusted Production Cost (APC) metric, which is a simplified metric to estimate the cost of serving load for a utility, or group of utilities. The APC metric calculates the cost of producing power as well as the cost of off-system purchases, while accounting for the revenues earned through off-system sales. The metric allows us to estimate the production cost savings that the WEIS members and the current SPP members would experience in the market participation scenarios simulated in the study. We calculate the APC metric for each case, and the comparison of the metric across cases provides an estimate of how much the cost to serve load changes due to market participation. In the RTO Case, we also determine the additional wheeling revenue that the WEIS members can expect to earn through additional off-system sales to the other areas of the WECC and include this as a benefit of market participation.

The Brattle team's simulations found that the creation of the WEIS real-time imbalance market with coordinated real-time imbalance transactions across the DC ties reduces APC by $9 million/year for WEIS members and by $7.1 million/year for the current SPP members. The WEIS Market produces benefits by allowing for increased flows of low-cost power from the western part of the SPP footprint across the DC ties into the WECC. Higher-cost generation backs down in the WEIS footprint to accommodate the inflows from SPP. This market transaction of power creates benefits on both sides of the DC ties.

The creation of the SPP West RTO creates benefits of $25 million/year for WEIS members and $24.2 million/year for current SPP members. The full integration of the WEIS footprint into the SPP RTO means power can flow from the current SPP footprint into Arizona, New Mexico, Utah, and other areas in the WECC while paying a single wheeling fee. As a result, the model shows increased power flows over the DC ties into the WECC that mostly pass through the WEIS footprint and are sold as off-system sales to other entities in the WECC. This creates benefits for WEIS members, through some purchases of lower-cost power from SPP and through additional wheeling revenues into the WECC, and creates benefits for SPP members that sell more power across the DC ties.

While the APC calculation captures system production costs caused by reduced hurdle rates, additional transmission availability, and dispatch optimization over a larger footprint, among others, the benefits we estimate in this study likely underestimate the true savings from the creation of the WEIS Market and expanding the SPP RTO. This production cost simulation will not capture market benefits associated with management of intra-hourly deviations for variable resources, uncertainty in load or renewables, generation or transmission outages, inefficiencies of bilateral trading, or operating reserves sharing, among others. The market benefits not captured by the APC metric are discussed further in Section III.B.

II. Modeling Approach and Assumptions

A. The Power System Optimizer (PSO)

For the simulations in this study, we used the Power Systems Optimizer (PSO) software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations.

A production cost model, like PSO, can be used as a tool to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirement, depancaked transmission and scheduling charges, changes in fuel costs, and jointly-optimized generating unit commitment and dispatch. PSO can be set up to produce hourly prices at every bus and generation output for each unit. The market operational results and prices produced by PSO can be used to estimate changes in generation output, fuel use, production cost, or other metrics on a unit, state, utility, or regional level.

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only. PSO has the capability to capture the effects on thermal unit commitment of the increasing variability due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system), as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe (though only an hourly timeframe was used in this study).

PSO uses mixed-integer programming to solve for optimized system-wide commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in jointly optimized competitive energy and ancillary services markets.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (e.g., load, fuel prices, etc.) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which would occur at different points in time and with different amounts of information about system conditions. Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights, which allows for a more realistic and more accurate representation of actual trading opportunities and transactions costs.

PSO can simulate initial cycles to optimize unit commitment, calculate losses, and do an initial optimization of unit dispatch. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the market design of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to mimic actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment. This is how we represent bilateral trading and the Western Energy Imbalance Market (EIM) and WEIS Market in the model.

B. Model Development

The integrated SPP-WECC model used in this study was developed initially as two separate models: a WECC model and an Eastern Interconnection model. Updates were made to these models separately in parallel work streams to control model-processing time and calibrate the individual models before introducing complications of combining the models. The two models were then combined across the seven DC ties to create an integrated model of both interconnections.

1. The WECC Model

The modeling assumptions used in this study are based off the 2028 WECC System Stability Planning Anchor Data Set (ADS) developed by WECC staff to conduct regional transmissions studies in the western U.S. The WECC ADS model assumptions are developed from data contributed by WECC members. The database includes an assumed generation portfolio for 2028 in the WECC, peak load and energy demand forecasts for 2028, a transmission topology reflective of expected 2028 transmission upgrades, wind and solar production templates based on historical hourly production profiles from NREL's 2009 database, and hydro profiles for normal hydrological conditions.

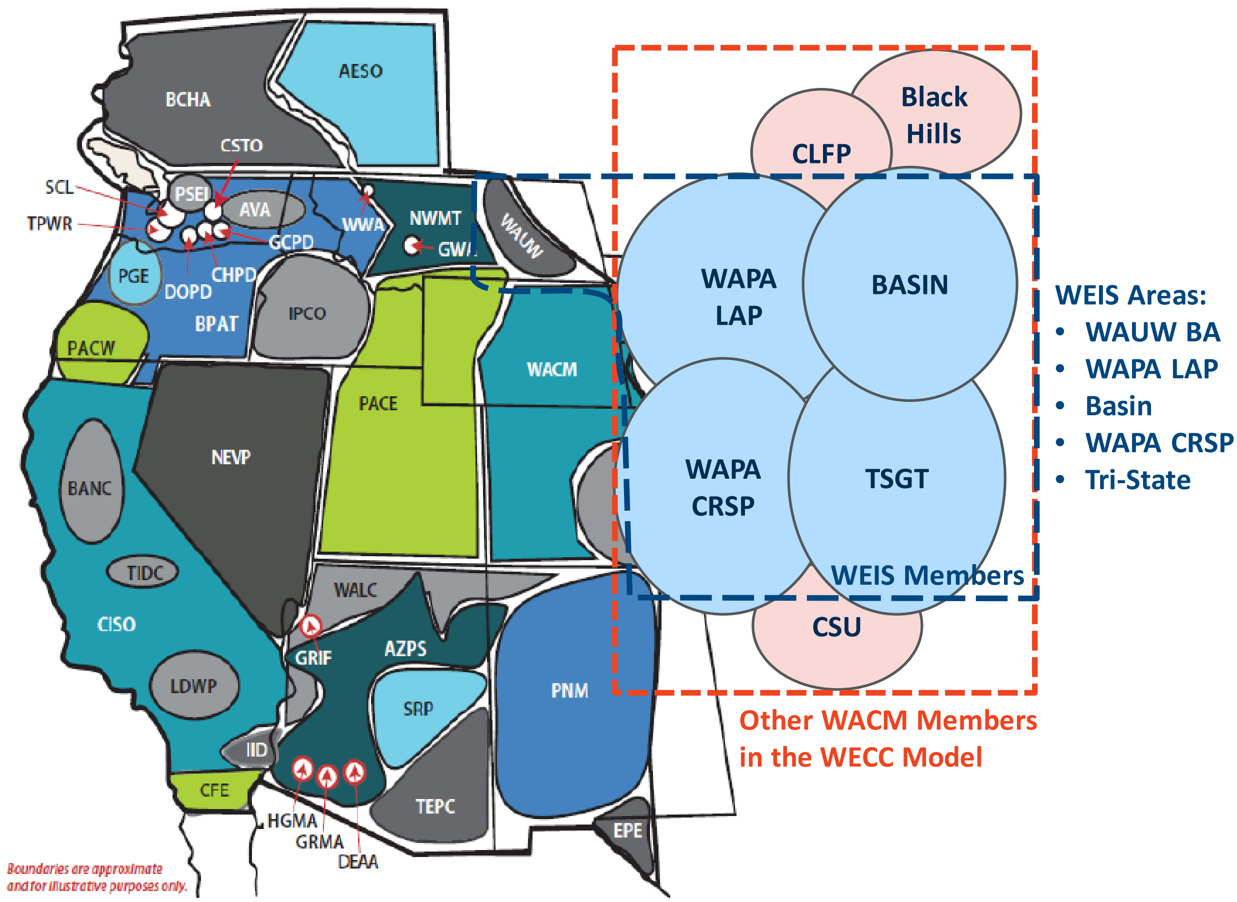
The WECC ADS model represents each Balancing Area (BA) in the WECC, implying that the WECC model has all the generation, load, and transmission mapped to one of the BAs in the WECC. Multiple members of the WEIS Market are located within the Western Area Power Administration (WAPA) Colorado Missouri (WACM) BA, along with some other non-WEIS entities. Therefore, simulating the impact of creating a market in the WEIS footprint on the individual WEIS members required a more granular representation of the WACM BA. We separated the generation, load, and transmission located in the WACM BA into sub-areas representing all the utilities that make up the WACM BA. We developed this more detailed representation of the WACM BA with the help and input of the WEIS members - WAPA, Tri-State, and Basin.

The WEIS entities provided us with the information to map the generation and transmission buses to their respective systems and with the updated data on their generation resources, fuel prices, and load to inform our 2028 modeling assumptions. We created a WECC model that contained all the BAs in the other parts of the WECC, and a utility-specific representation of the WACM BA footprint. The utility-specific representation of the WACM BA contained individual areas for WAPA's Loveland Area Projects (LAP) system, WAPA's Colorado River Storage Project (CRSP) system, Basin's Western Interconnection system, and Tri-State's system.[1] The proposed WEIS members include three other entities within the

[1] Tri-State has generation, transmission, and load within the Public Service Company of Colorado (PSCO) BA and within the Public Service Company of New Mexico (PNM) BA. Since both of these areas have announced plans to join the EIM, Tri-State provided us with the information and data to separate their system between the parts going into the WEIS and the parts with the PSCO and PNM BAs.

WACM BA, the Wyoming Municipal Power Agency (WMPA), Deseret Power Electric Cooperative (Deseret), and the Municipal Energy Agency of Nebraska (MEAN).[2] The load and generation that these entities plan to bring into the WEIS are included in the model, within the Basin zones (WMPA), LAP zone (MEAN), and the CRSP zone (Deseret). The proposed WEIS footprint also includes the portion of the WAPA Upper Great Plains system that is in the WECC (the WAUW BA).[3] Figure 2 indicates the WECC balancing areas represented in the model, identifies the WEIS member areas modeled in our study, and illustrates the separation of the WACM BA into the WEIS members and other utilities.

FIGURE 2: WECC BALANCING AREAS AND MODELED AREAS IN THE WEIS FOOTPRINT



The WEIS ADS model was developed to operate in GridView, another nodal production cost simulation software. To conduct the simulations for this study, we converted the ADS model to operate in the PSO software. This conversion made the model compatible with our Eastern Interconnection model, and allowed us to represent day-ahead operations and real-time operations in one simulation. The PSO

2 The WACM BA includes other utilities that are not planning to join the WEIS, such as Black Hills Power, Cheyenne Light Fuel and Power, and Colorado Springs Utilities (Colorado Springs Utilities has moved to the PSCO BA, but at the time the WECC ADS model was developed it was part of the WACM BA). In the model used for this study, we represent these areas as their own zones within the WECC.

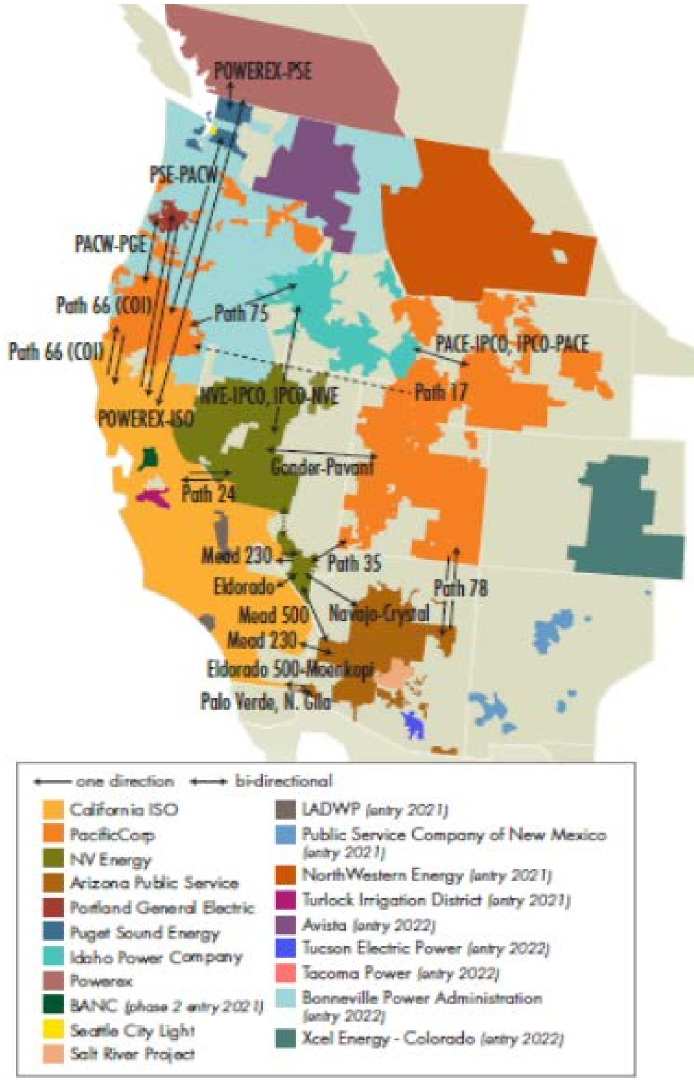
3 The majority of the WAPA Upper Great Plains system is in the Eastern Interconnection and is already a member of the SPP RTO market.

model is equipped with the ability to simulate optimization decisions in different cycles, with each cycle representing the market structures and information at different decision-marking timeframes. For example, in PSO we can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power in the WECC, and a real-time economic dispatch, reflecting the energy imbalance markets in the WECC.

The combined day-ahead and real-time model of the WECC includes a representation of the CAISO-administered Western Energy Imbalance Market (EIM) that includes all the utilities that are currently members and the utilities that have announced their intention to join prior to 2028.[4] The representation of the EIM in the WECC model ensures the portion of the WECC that does not intend to join the WEIS is properly simulated by the model. To simulate market transactions in the EIM, our team developed modeling assumptions to represent the transmission capability between EIM members. For the existing EIM members, we utilized information provided in the quarterly Western EIM Benefits Report, shown in Figure 3, to approximate the transfer capability between the existing members. For the prospective members of the EIM, we estimated the transfer capability between the members using the WECC 2019 Path Rating Catalog, which is available to WECC members, and other publicly available sources.

4 All active EIM members were modeled as EIM participants, and pending members: Los Angeles Department of Water and Power (LADWP), Public Service Company of New Mexico (PNM), Avista (AVA), Tucson Electric Power (TEPC), Bonneville Power Administration (BPA), Balancing Authority of Northern California (BANC), Turlock Irrigation District (TIDC), Public Service Company of Colorado (PSCO), Platte River Power Authority (PRPA), Black Hills Colorado Electric (BHCE), and Colorado Springs Utilities (CSU) were also modeled as EIM participants.
https://www.westerneim.com/Pages/About/default.aspx

FIGURE 3: TRANSFER PATHS BETWEEN CURRENT EIM PARTICIPANTS



The WECC ADS model assumptions reflect the physical limits of the transmission system in the WECC, as shown in the WECC Path Ratings Catalog. To reflect the inefficiencies of bilateral transmission scheduling we apply a 10% de-rate to all the transmission paths in the model that are not part of an RTO market (all paths external to the CAISO footprint). This includes the transmission paths in and around the WEIS footprint, such as TOT 2A, TOT 3, and TOT 5.

The last modeling assumption update made to the WECC ADS model is to adjust prices for inflation. The cost data in the ADS model are expressed in 2018 dollars, which were inflated to 2020 dollars using an assumed inflation rate of 2% consistent with the inflation rate used by SPP to adjust their modeling assumptions. Therefore, all results presented in this report are in 2020 dollars.

2. The Eastern Interconnection Model

The Eastern Interconnection model was developed based on a database created by the Newton Energy Group (NEG), which is the same company that developed and licenses the PSO software. The NEG model includes SPP, MISO, and the neighboring areas,[5] and was built using publically available data from FERC filings on the transmission topology, the generation resources, and load in these regions.

The Brattle team altered the NEG model to be consistent with the WECC ADS assumptions. We updated the modeling assumptions to include the retirement and addition of generation resources as planned for 2028 (in the SPP and MISO footprints, as provided by SPP). We also altered the transmission topology to include major transmission constraints identified in SPP's 2020 ITP, and adjusting the hourly solar and wind production profiles to match the same historical year used in the WECC model (2009 from NREL's database).

We updated the fuel prices in the model to reflect assumptions provided by SPP. All the fuel prices in the model, except for natural gas prices, were updated to match the prices in SPP's 2020 ITP. The natural gas prices used in the model were developed from SPP's 2028 Henry Hub forecast and the corresponding forecasts for SPP-internal locations. As explained in the next section, the SPP natural gas price forecasts were used to develop prices used in the WECC as well.

The model simulates unit commitment and dispatch across all the regions represented in the model based on the relative economics and operating characteristics of the generation resources in each region. The model also simulates the optimal transfer of power across the SPP-MISO seam, based on the cost of power on each side of the seam, the transmission capability between the regions, and subject to a hurdle rate. Power transfers between all the other regions in the Eastern Interconnection model are set at fixed levels in each hour based on the historical flow data from the NEG model (shifted to align peak and off peak periods with 2028).

3. The Integrated Eastern Interconnection-WECC Model

Our team developed the two models independently and then combined them across the seven DC ties that connect the Western and Eastern Interconnections. In the Status Quo Case, the flows across the DC ties are modeled as fixed hourly schedules, which cannot be adjusted by the model to take advantage of price differences across the ties. The flows across the DC ties are based on the historical flows from 2019 (shifted to alight peak and off peak periods with 2028) provided by SPP.

The combined model contains three cycles to simulate unit commitment and dispatch decisions along different timeframes and within different market structures. The three cycles simulated in the model are:

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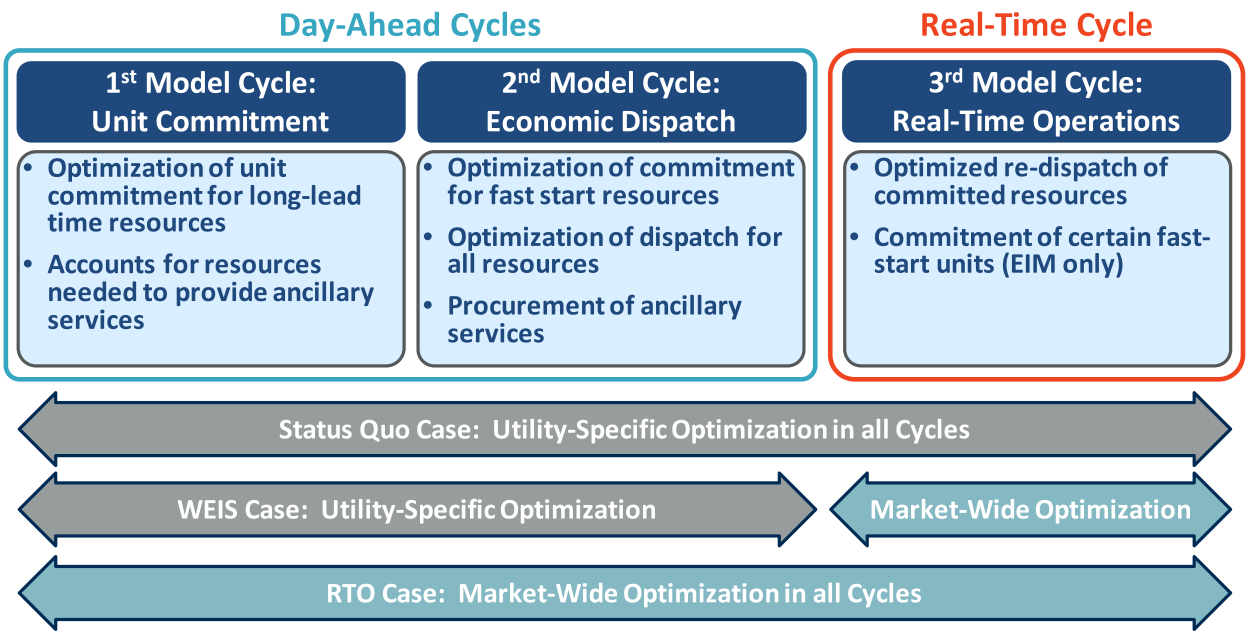
5 Neighboring areas include SPA, EEI, SPC, IESO, SERC, LG&E, PS, SOCO, TVA, AEP, COMED, DEOK, MH, and AECI.

- **Day-Ahead Unit Commitment Cycle:** the model optimizes the unit commitment decisions for long-lead time resources, such as coal and nuclear plants, based on the relative economics and operating characteristics of the resources (e.g., minimum run time, ramping rate, maintenance schedules, etc.) and the transmission constraints reflected in the model. The model will also ensure that enough resources are committed to serve load, accounting for average transmission losses and the need for ancillary services.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for unit commitment for fast start resources and the optimal level of dispatch for all resources in the model based on the relative economics of the resources. In this cycle, the model will solve for the provision of ancillary services for each area in the WECC and each market footprint in the Eastern Interconnection.
- **Real-Time Cycle:** this cycle allows us to simulate the operation of the real-time imbalance markets, such as the EIM and the WEIS. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for certain fast-start resources if the real-time market rules allow for re-commitment.

These three cycles will take on different assumptions depending on the market structure in place. For example, in a bilateral setting as currently exists in the WEIS footprint, all three of these cycles would be set up to analyze utility-specific unit commitment and dispatch decisions. In the Status Quo Case, each of these three cycles would include hurdle rates and transmission wheeling fees between the utility areas to limit the amount of power transactions that can take place between the utilities. In this way, we replicate the operation of the bilateral market, where utilities demonstrate a strong preference to commitment and dispatch their own resources instead of relying upon the resources of a neighboring entity. In an RTO market, all three of the cycles would be set up to simulate market-wide optimization of unit commitment and dispatch. In the RTO setting, there would be no hurdle rates between market members in any cycle, allowing the model to perfectly optimize unit operation in the market footprint. In the WEIS Case, the day-ahead cycles would operate like the bilateral setting and the real-time cycle would operate like the market. Figure 4 describes the three cycles simulated in the model and how they are set up to reflect the operation of different market structures.

FIGURE 4: MODELED CYCLES IN PSO



The natural gas prices in the unified model were developed to ensure consistency between fuel prices in the Western and the Eastern Interconnections. We developed locational fuel prices for points in the Eastern Interconnection model based on the 2028 Henry Hub forecast provided by SPP, and information given by SPP on the differentials between locational prices and the Henry Hub. The natural gas prices in the WECC region were developed using historical differential between each gas pricing location in WECC and the Henry Hub, which were applied to the 2028 Henry Hub forecast provided by SPP. Table 1 shows the average annual 2028 price (in 2020 dollars) of natural gas in selected regions of the model.

TABLE 1: AVERAGE ANNUAL NATURAL GAS PRICE MODELING ASSUMPTIONS (2020 $/MMBTU)

WECC Model Locations		Eastern Interconnection Model Locations	
Arizona North	$3.5	Louisiana	$3.5
Arizona South	$3.3	Henry Hub	$2.5
British Columbia	$3.1	Minnesota	$4.4
California PG&E	$4.6	Oklahoma	$3.6
California SDGE	$4.5	Southeast	$3.8
Colorado	$2.3	Texas Southeast	$3.4
Idaho South	$2.7	West SPP	$3.3
Malin	$2.9	Wisconsin	$3.8
Montana	$2.3		
Nevada North	$2.6		
Nevada South	$3.4		
New Mexico North	$2.6		
New Mexico South	$2.5		
SoCal Border	$3.4		
SoCal Gas	$4.5		
Texas West	$2.6		
Utah	$2.5		
Washington	$3.1		
Wyoming	$2.3		

C. Description of the Cases Simulated

The three cases simulated in this study allow us to estimate the production cost benefit of creating the WEIS and of extending the SPP RTO market to the WEIS footprint. The three cases simulated are: 1) the Status Quo Case, 2) the WEIS Case, and 3) the RTO Case. These cases differ only by the market structure (scope of optimization, hurdle rates in each cycle, and derates on transmission paths to approximate inefficiencies under the Status Quo Case). Therefore, a comparison of the production costs and system operation across the cases allows us estimate the impact of the two potential market structures.

The Status Quo Case simulates operation of the Eastern Interconnection and WECC with the current market structures with the current/planned members. These includes the SPP, MISO, and CAISO market footprints as currently constituted, and the EIM footprint with all current members and the utilities that have announced they will join before 2028.

As described in the previous section, the model simulates unit commitment and dispatch decisions in three sequential optimization cycles (see Figure 4). The Status Quo Case contains several different market structures, depending on the region, such as RTO markets in SPP, MISO, and CAISO, and an energy imbalance market in the EIM. Therefore, the modeling assumptions in each cycle of the model vary for the different regions of the model. The assumptions in all areas of the model, except the WEIS footprint, are the same in all three cases. Therefore, we focus on highlighting the differences between the modeling assumptions in the WEIS footprint.

TABLE 2: MODELING ASSUMPTIONS FOR THE WEIS FOOTPRINT ACROSS CASES

Market Design Assumption	Status Quo Case	WEIS Case	RTO Case
Hurdle Rate between WEIS Members	• $8/MWh Unit Commitment • $4/MWh Dispatch	• $8/MWh Unit Commitment • $4/MWh Dispatch • $0/MWh in real-time WEIS Market	• $0/MWh for all commitment and dispatch
Transmission Capacity	• All paths around the WEIS derated 10%	• Transmission in the WEIS rated at physical limits	• Transmission in the WEIS rated at physical limits
DC Ties	• DC ties flows fixed to historical 2019 levels in all day-ahead and real-time	• DC ties flows fixed to historical 2019 levels in all day-ahead • Model optimizes DC ties flows based on price in real-time	• Model optimizes DC ties flows based on price in day-ahead and real-time

III. Study Results

This section of the report summarizes results of the simulations described above. The first part of this section focuses on two computed metrics, which we estimate using the results of the simulations as inputs. These two metrics estimate the market participation benefit for the SPP and prospective WEIS members for the two market structures considered. The two benefits we focus on are (1) the Adjusted Production Cost (APC) metric, which approximates of the cost to serve load, and (2) in the RTO Case only, the additional wheeling revenues that the WEIS members can expect to collect due to increased wheel-through transactions from SPP to the rest of the WECC.

We also describe a list of market participation benefits that are not analyzed in this study. Like all production cost simulations, this study does not capture all the operational details and nuances experienced during actual operation of the power system. Therefore, some of the benefits of participation in a regional energy imbalance market or RTO market are not accounted for in this study.

A. Market Benefits Estimated in this Study

1. Adjusted Production Cost Benefits

The study calculates the Adjusted Production Cost (APC) metric, which is a simplified metric to estimate the cost of serving load for a utility or a group of utilities (in this study the metric was calculated for the aggregate WEIS footprint and the SPP footprint). The APC metric calculates the cost of producing power as well as the cost of off-system purchases, while accounting for the revenues earned through off-system sales. The APC metric does not account for all the costs incurred to serve load. For example, the metric does not account for cost-based contracts for generation, marginal loss refunds, revenues from financial transmission rights, and other costs and revenues that may accrue to market participants.

The metric allows us to estimate the production cost savings that the WEIS and SPP members would experience in the market participation scenarios simulated in the study. The APC reflects the net costs associated with production, purchases, and sales of wholesale power, and is calculated as:

Adjusted Production Cost =

(+) Generator costs (fuel, start-up, and variable operation and maintenance (O&M)) for generation owned or contracted by the SPP and WEIS entities;

(+) Costs of market purchases by the SPP and WEIS entities from other generators and imports from neighboring regions; and

(−) Revenues from market sales and exports by the SPP and WEIS entities.

The APC metric is calculated for each case, and the comparison of the metric across cases provides an estimate of how much the cost to serve load changes due to market participation. For example, the APC metric for the SPP footprint in the Status Quo Case minus the APC metric in the RTO Case indicates how much the cost of serving load will decrease for the SPP members if the WEIS entities join the RTO market.

2. Additional Wheeling Revenue (RTO Case Only)

In the RTO Case, we estimate the additional wheeling revenue that would be generated for the WEIS entities due to participation in an expanded SPP RTO. The expanded RTO in the WEIS footprint would imply a unified transmission tariff in the WEIS and hurdle-free transferring of power over the DC ties between the WEIS and SPP footprints. The unified transmission tariff in the RTO Case can create additional wheeling revenues in two ways. First, the WEIS members will be able to utilize each other's transmission systems without incurring any wheeling fees to sell power to other entities in the WECC, which would create additional wheel-out revenues for the entire WEIS footprint. Second, under the expanded RTO power would be able to flow from the eastern side of the DC ties in SPP across the ties, through the WEIS footprint, and be sold to other entities in the WECC that share a transmission connection with the WEIS while only paying a single wheeling fee. These wheel-through transactions may not necessarily reduce production costs for WEIS members, as the power flows through and out of the footprint, but it will generate wheeling revenues for the WEIS members.

We calculate the additional wheeling revenue for the WEIS members by comparing the MWh of exports from the WEIS entities to the rest of the WECC in the Status Quo Case against the exports in the RTO Case. The additional MWh of export flows are multiplied by an estimate of the WEIS RTOR. The WEIS RTOR is estimated as the load-weighted average of the individual utility wheeling rates. The actual RTOR for a unified WEIS footprint will be determined in discussions between the prospective members, and will change over time as transmission costs in the region change. Based on the information on wheeling fees provided by the WEIS members and the relative loads of each member, we estimated a RTOR for the unified WEIS at $5.75/MWh. Therefore, we applied this rate to difference between the WEIS exports in the RTO Case and the Status Quo Case.

B. Market Benefits Not Estimated in this Study

Production cost simulations, such as those conducted in this study, are helpful for understanding the benefits of participating in a regional market, but there are limitations of such simulations as tools for understanding all the benefits created from market participation. Production cost models are powerful tools: they jointly simulate generation dispatch and power flows to capture the actual physical characteristics of both generating plants and the transmission grid, including the complex dynamics between generation and transmission availability, energy production and operation, and ancillary services requirements. These types of simulations provide valuable insights to both the operations and economics of the wholesale electric system in the entire interconnected region. For that reason, production cost models are used by every ISO and RTO, and most utilities, for transmission planning purposes.

However, similar to most other production cost simulations, the simulations undertaken for this study have their limitations and likely yield conservatively low estimates of the benefits for SPP and the WEIS members. The specific limitations include:

- This study does not assess the benefits of **improved management of load and generation uncertainties** provided by a regional energy imbalance market or RTO market, particularly as it relates to the **integration and balancing of increasing amounts of renewable generation**. The study simulates unit commitment and dispatch deterministically based on perfect foresight of all loads and available generation, including hourly renewable generation output, for both day-ahead and real-time operations. The simulations do not consider uncertainties in loads, generation outages, or the level of wind and solar generation that exist between the time utility-specific unit commitment and dispatch decisions are finalized (on a day-ahead and intra-day basis) and when the real-time energy imbalance markets would make their unit commitment (in the EIM) and dispatch decisions. Therefore, the simulations do not capture the benefit of the markets in managing this uncertainty. Having a regional market provides the system operator with a larger pool of resources and optimization tools to manage unexpected changes of generation and load between day-ahead and real-time operations, thereby reducing costs, reducing the need for reserves and ramping capability, and increasing reliability, particularly when integrating large amounts of variable resources, such as wind and solar generation.

- The simulations have been performed on an hourly basis and thus do not capture the additional benefits the WEIS and RTO would provide by balancing loads and generation (and the related uncertainties) on an **intra-hour** basis.
- The simulations are based on **normal weather, average hydrology, normal monthly energy and peak load, and normal generation outages** without considering additional benefits realized during unusually challenging operational conditions. For example, atypical weather patterns (such as extreme cold temperatures or very hot and humid conditions) could create large swings of power flows across a system or other operational challenges. Challenging conditions such as these tend to increase the benefit of regional energy imbalance markets.
- The study does not account for the **reliability benefits** of belonging to a larger regional market footprint resulting from a **reduction in reserves** needed to meet operational and flexibility requirements.
- The simulations do not consider the additional transmission constraints and operational challenges on the power grid during **transmission-related outages**. Transmission limits are reflected in the simulations, but the modeling does not account for transmission outages and the additional unexpected operational challenges they create. The greater flexibility provided by integrated regional market operations yields higher cost savings and improved reliability during transmission outages.
- We do not assume that the improved incentives of operating in a price-transparent and competitive regional market would improve **generator efficiency and availability**, as has been documented by the experience in other regional markets.
- The Status Quo Case in the WEIS footprint **does not fully capture inefficiencies of bilateral trading practices** in terms of less flexible bilateral trading blocks (*e.g.*, 16-hour blocks at 25 MW increments) and congestion caused by unscheduled power flows.
- The simulations do not capture any benefits achievable through **improved regional coordination and optimization of hydropower resources**. We have left hydro dispatch unchanged between the Status Quo Case and the two market participation cases, leaving out benefits associated with allowing the flexible portion of hydro resources to be dispatched more optimally by the regional market (subject to their operating constraints).
- The study does not include savings from more **efficient planning for transmission projects** nor economic **retirement of generation** under market cases.
- Finally, the study does not capture any **changes in transmission cost allocation** as a result of WEIS entities joining the WEIS Market or SPP RTO.

The benefits estimated in this study, as well as the benefits described above that are not accounted for in the study, would need to be weighed against the administrative costs associated with participating in the respective regional energy imbalance markets.

C. Market Benefit Results

In this section, we present the estimated market participation benefits for two possible future market structures that include the prospective WEIS members. First, we present the production cost savings created by the formation of the WEIS Market for real-time energy imbalance transactions. Next, we present the production cost savings created by extending the SPP RTO market to the WEIS footprint, and the increased wheeling revenues that would be generated in the RTO market.

1. WEIS Market Benefits

The creation of the WEIS reduces APC for the entire study footprint (the WEIS and SPP) by $16.1 million/year (0.3% of APC). This benefit is recognized as $9 million/year (4.1% of APC) for the WEIS members and $7.1 million/year for the SPP members (0.14% of APC). In this case, benefits are driven by increased transfers of low-cost power over the DC ties from SPP to WEIS. The creation of the WEIS allows for an increase in profitable trading across the DC ties, resulting in increased flows into the WEIS in real-time. The inflow of power from SPP allows WEIS members to ramp down expensive generation and save on fuel costs.

Figure 5 shows the reduction in APC for the WEIS members due to the creation of the imbalance market. The table displays the aggregate reduction in APC in the bottom right hand corner of the table, which indicates a reduction of just over $9 million/year. The remainder of the table provides additional insight into the results, and shows how system operations and costs in the WEIS footprint change due to the creation of the WEIS. The columns Figure 5 are divided into three sections labeled “GWh,” “$/MWh,” and “Total ($1000s/Year).” The "GWh” section details the quantity of production within the WEIS in both cases, and the quantity of off-system market purchases and sales in both cases. The section labeled “$/MWh” indicates the average cost of production within the WEIS and the price of off-system purchases and sales, in both the Status Quo and WEIS Cases. The final section of the table, labeled "Total ($1000s/Year),” shows the overall production costs, purchase costs, and sales revenues under both cases. The comparison of the final costs of production and purchases and the revenues from sales under both cases illustrates how much the APC for the WEIS entities will change in the WEIS Case versus the Status Quo Case.

FIGURE 5: DETAILED MARKET PARTICIPATION BENEFITS FOR THE WEIS FOOTPRINT STATUS QUO CASE VS. WEIS CASE

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Status Quo**	**WEIS in SPP**	**Difference**	**Status Quo**	**WEIS in SPP**	**Difference**	**Status Quo**	**WEIS in SPP**	**Difference**
Production	29,011	28,150	**-861**	$8.78	$8.54	**-$0.24**	$254,803	$240,386	**-$14,417**
Purchases									
DA & Bilateral Market	2,540	2,531	**-9**	$35.61	$34.95	**-$0.65**	$90,458	$88,464	**-$1,994**
Real-Time Market	0	1,433	**1,433**	$40.50	$12.49	**-$28.00**	$9	$17,903	**$17,894**
Sales									
DA & Bilateral Market	4,358	4,405	**47**	$28.75	$28.50	**-$0.25**	$125,281	$125,543	**$262**
Real-Time Market	0	515	**514**	$9.50	$19.92	**$10.42**	$5	$10,255	**$10,250**
Total	**27,193**	**27,193**	**0**	**$8.09**	**$7.76**	**-$0.33**	**$219,984**	**$210,954**	**-$9,030**

Figure 5 illustrates how the WEIS lowers the APC of its members. Given the ability to purchase and trade in the real-time market, the WEIS members make 1,433 GWh of market purchases in the imbalance market compared to almost no purchases in the real-time in the Status Quo. The WEIS members also make about 514 GWh of real-time market sales in the WEIS Case. To accommodate these additional market purchases and sales, the WEIS entities reduce their own production by about 860 GWh, saving over $14.4 million/year in production costs. Taken together, these impacts result in over $9 million/year in APC savings.

FIGURE 6: DETAILED MARKET PARTICIPATION BENEFITS FOR THE SPP FOOTPRINT STATUS QUO CASE VS. WEIS CASE

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Status Quo**	**WEIS in SPP**	**Difference**	**Status Quo**	**WEIS in SPP**	**Difference**	**Status Quo**	**WEIS in SPP**	**Difference**
Production	247,911	249,127	**1,217**	$16.34	$16.28	**-$0.06**	$4,050,725	$4,055,057	**$4,332**
Purchases									
DA & Bilateral Market	70,553	70,399	**-154**	$28.85	$28.81	**-$0.04**	$2,035,487	$2,028,220	**-$7,267**
Real-Time Market	925	1,316	**391**	$16.53	$26.00	**$9.47**	$15,294	$34,224	**$18,930**
Sales									
DA & Bilateral Market	29,671	29,743	**72**	$28.90	$28.78	**-$0.12**	$857,396	$855,877	**-$1,519**
Real-Time Market	957	2,339	**1,382**	$10.58	$14.87	**$4.29**	$10,121	$34,780	**$24,658**
Total	**288,760**	**288,760**	**0**	**$18.13**	**$18.10**	**-$0.02**	**$5,233,989**	**$5,226,845**	**-$7,144**

Figure 6 demonstrates the overall reduction of $7.1 million/year in APC for the SPP footprint, in the bottom right hand corner. The table shows that the SPP footprint has an increase of real-time market sales of almost 1,400 GWh between the WEIS and Status Quo Cases (from 957 GWh in Status Quo to 2,339 GWh). SPP members are able to make these sales at an average price of $14.87/MWh, resulting in an increase in real-time market sales revenue of $25 million/year. This increase in sales revenue is offset by an increase in purchasing costs in the real-time market in the WEIS Case (an increase of $18.9 million/year). However, the overall increase in sales revenue between the two cases is large enough to drive an overall net reduction in APC of $7.1 million for the SPP footprint between the WEIS Case and Status Quo Cases.

2. RTO Market Benefits

The expansion of the SPP RTO market to the WEIS members creates benefits for the combined study footprint (the WEIS and SPP) of over $49 million/year (0.6% of APC), including over $25 million/year (11.4% of APC) for WEIS members and $24 million/year (1.3%) for current SPP members. The $25 million/year of the benefit for the WEIS members includes $8.5 million/year in reduced APC and $16.7 million/year in the additional wheeling revenues. The APC savings in the RTO Case are generated by additional off-system sales to neighboring areas in the WECC enabled by the joint transmission tariff created in the RTO. In this case, both the WEIS and the SPP members increase production to make profitable sales to neighboring entities, creating increased sales revenues and overall benefits.

Figure 7 illustrates the benefits for WEIS members in the RTO Case. The table shows an increase in day-ahead sales of 728 GWh between the two cases, creating an increase in sales revenue of $17.8 million/year. To accommodate the additional off-system sales, the WEIS members increase production by 720 GWh, increasing their production costs by $19 million/year. In the RTO Case, the WEIS members are able to make market purchases at a lower cost ($31.74/MWh vs. $35.61/MWh), which creates a benefit of $9.8 million/year. Taken together, the increase in production costs is more than offset by the decrease in purchase costs and increase in sales revenues. Overall, the WEIS members experience $8.5 million/year of adjusted production cost savings. The WEIS members also benefit from the increased wheeling fee generated by the additional off-system sales that occur in the RTO Case. The additional wheeling fees amount to almost $16.7 million/year.

FIGURE 7: DETAILED MARKET PARTICIPATION BENEFITS FOR THE WEIS FOOTPRINT STATUS QUO CASE VS. RTO CASE

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Status Quo**	**RTO**	**Difference**	**Status Quo**	**RTO**	**Difference**	**Status Quo**	**RTO**	**Difference**
Production	29,011	29,731	**720**	$8.78	$9.21	**$0.43**	$254,803	$273,820	**$19,017**
Purchases									
DA and Bilateral Market	2,540	2,540	**0**	$35.61	$31.74	**-$3.87**	$90,458	$80,611	**-$9,848**
Real-Time Market	0	24	**24**	$40.50	$16.24	**-$24.25**	$9	$395	**$386**
Sales									
DA and Bilateral Market	4,358	5,086	**728**	$28.75	$28.13	**-$0.62**	$125,281	$143,065	**$17,784**
Real-Time Market	0	16	**16**	$9.50	$14.45	**$4.95**	$5	$237	**$232**
Adtnl. Wheeling-Out Revenue									**$16,687**
Total	**27,193**	**27,193**	**0**	**$8.09**	**$7.78**	**-$0.31**	**$219,984**	**$211,524**	**-$25,148**

Figure 8 demonstrates the $24.2 million/year reduction in APC for the SPP footprint under the RTO Case. This reduction is driven primarily by an increase in market sales into the WECC, resulting in a $20.6 million increase in day-ahead off-system sales revenue compared to the Status Quo Case. This increase in sales, combined with a 1,061 GWh decrease in day-ahead market purchases, means an increase in production of 2,049 GWh within the SPP footprint compared to the Status Quo Case. The increase in sales revenues drives an overall APC reduction of $24 million/years.

FIGURE 8: DETAILED MARKET PARTICIPATION BENEFITS FOR THE SPP FOOTPRINT STATUS QUO CASE VS. RTO CASE

	GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Status Quo**	**RTO**	**Difference**	**Status Quo**	**RTO**	**Difference**	**Status Quo**	**RTO**	**Difference**
Production	247,911	249,960	**2,049**	$16.34	$16.17	**-$0.17**	$4,050,725	$4,042,855	**-$7,870**
Purchases									
DA and Bilateral Market	70,553	69,491	**-1,061**	$28.85	$29.36	**$0.51**	$2,035,487	$2,040,084	**$4,596**
Real-Time Market	925	867	**-59**	$16.53	$17.12	**$0.59**	$15,294	$14,837	**-$457**
Sales									
DA and Bilateral Market	29,671	30,651	**980**	$28.90	$28.64	**-$0.25**	$857,396	$878,009	**$20,613**
Real-Time Market	957	906	**-51**	$10.58	$11.00	**$0.42**	$10,121	$9,965	**-$157**
Total	**288,760**	**288,760**	**0**	**$18.13**	**$18.04**	**-$0.08**	**$5,233,989**	**$5,209,802**	**-$24,187**

D. System Operation Results

In addition to providing us with the information to calculate the APC and wheeling revenue benefits, the simulations provide operational results for the SPP and WEIS footprints, including generation mix by fuel type and transmission flows. We present the generation by fuel type in the Status Quo Case to illustrate the fuel mix assumed for 2028 in SPP and the WEIS footprints. Given the importance of the DC ties in the WEIS Market and the expanded SPP RTO, we also present the flows across the four DC ties that are within the WEIS footprint in all the cases simulated.

1. Generation by Fuel Type

This section presents the generation mix by fuel type for the SPP and WEIS footprints simulated in our model. The generation mix is assumed to change considerably by 2028 (the year simulated in this study) compared to the current resource mix. In the WEIS region, additional renewable sources are expected to come online and some coal-fired resource as planned for retirement. We worked with the WEIS members to develop these modeling assumptions based on the latest plans for generation additions and retirements. Figure 9 illustrates the 2028 supply mix in the WEIS footprint. The 2028 generation mix in the WEIS is made up of over 15 TWh of coal generation (51% of the total generation), 9.1 TWh of hydro (30%), 3.4 TWh of wind (11%), 1.5 TWh from solar (5%), and less than 1 TWh from natural gas.

FIGURE 9: WEIS FOOTPRINT 2028 GENERATION SUPPLY MIX (TWH)

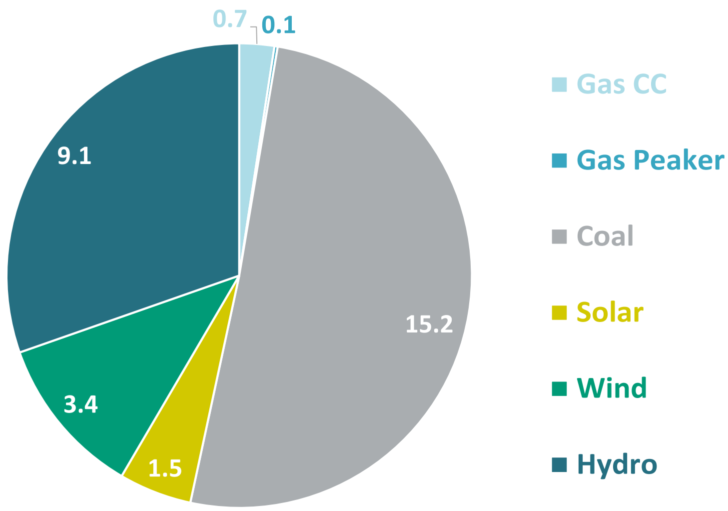
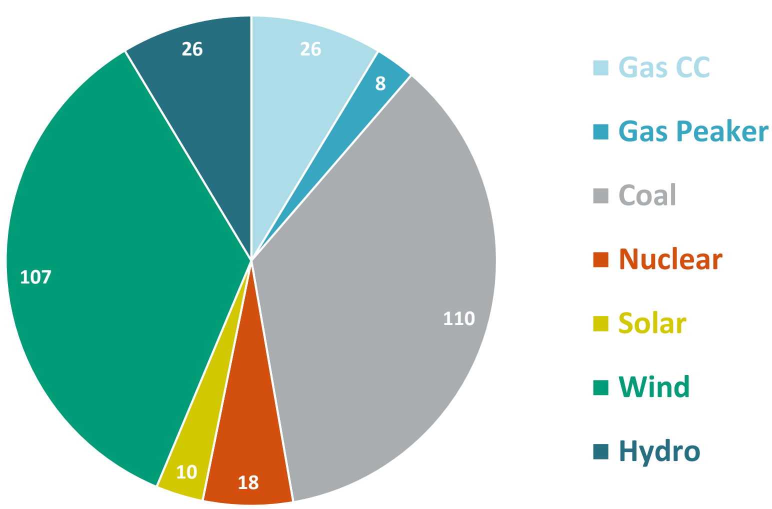


Figure 10 illustrates the generation supply mix in the SPP footprint for 2028, which is made up of 110 TWh of coal-fired generation (36% of the total generation), 107 TWh of wind (35%), 34 TWh from natural gas (11%), 26 TWh from hydro (9%), 18 TWh from nuclear (6%), and 10 TWh from solar (3%).

FIGURE 10: SPP FOOTPRINT 2028 GENERATION SUPPLY MIX (TWH)

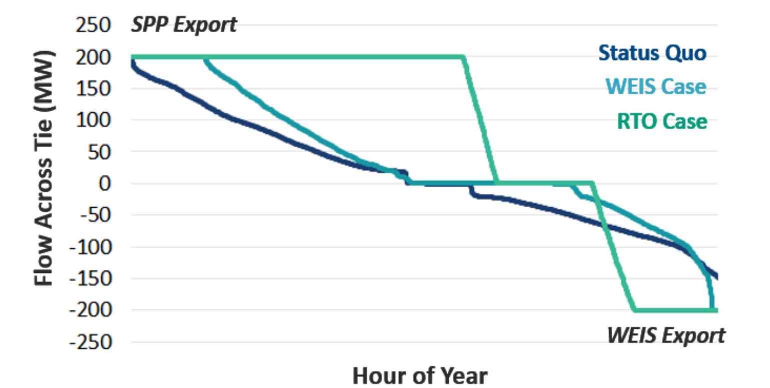


2. DC Tie Flows

This study finds that the ability to optimize flows over the DC ties is a major contributor to creating the benefits of market participation. Therefore, in this section, we illustrate how the flows over the four DC ties that connect SPP to the WEIS change between the three simulated cases. Figure 11 through Figure

14 show the flows at the Miles City tie, the Stegall tie, the Rapid City tie,[6] and the Sidney tie. In the Status Quo Case, the flows are fixed at 2019 historical hourly amounts (shifted to align peak and off peak periods with the 2028 calendar year). Therefore, the dark blue line on each of the four figures shows the flow duration curve based on those historical 2019 flows. In the WEIS Case, the four DC ties are modeled at the fixed 2019 hourly flows in the day-ahead unit commitment and dispatch cycles of the model, but we allow optimization to occur in the real-time cycle of the model. Therefore, the model has some limited ability to adjust flows in response to prices on either side of the tie in the WEIS Case, but not complete ability to optimize based on price. The teal line on each figure shows the flows in the WEIS Case, which demonstrate some movement away from the historical flows to better reflect price signals. Lastly, in the RTO Case, the model is able to fully optimize flows over the DC ties in all cycles of the model. Therefore, the green lines in the figures demonstrate a fully optimized flow duration curve at each of the four DC ties.

FIGURE 11: MILES CITY TIE FLOWS



On the Miles City DC tie, we see that flows under the Status Quo Case are approximately evenly split between importing and exporting from SPP. In almost no hours of the year is the full capacity of the Miles City tie utilized, and in about 10%-15% of the hours of the year, there are no flows over the tie in the Status Quo Case. In the WEIS Case, flows over the Miles City tie shift more in the direction of exporting from SPP to the WEIS. Although there are still many hours of the year when the tie's capacity is not fully utilized (or utilized at all). In RTO Case, SPP becomes a large exporter to the WEIS, which implies completely flipping the direction of flows in many hours of the year.

6 The rights on the Rapid City tie are shared between Basin and Black Hills Power. Since Black Hills Power is not a prospective member of the WEIS, only the portion of the Rapid City tie that is controlled by Basin is modeled as part of the two simulated market structures. The portion of the Rapid City tie that is controlled by Black Hill Power is modeled at the 2019 fixed hourly flows in all three cases.

FIGURE 12: STEGALL TIE FLOWS

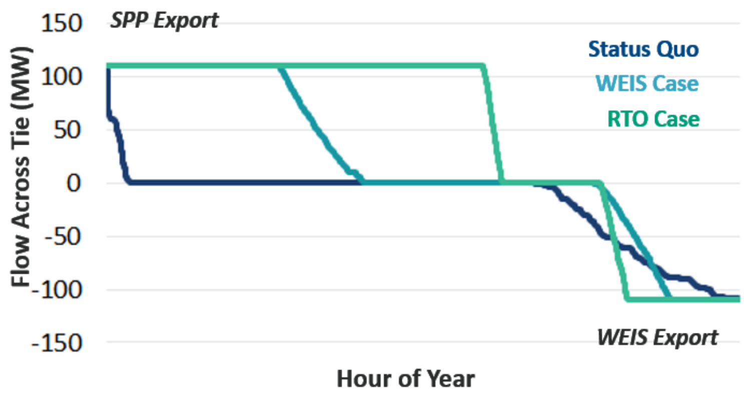
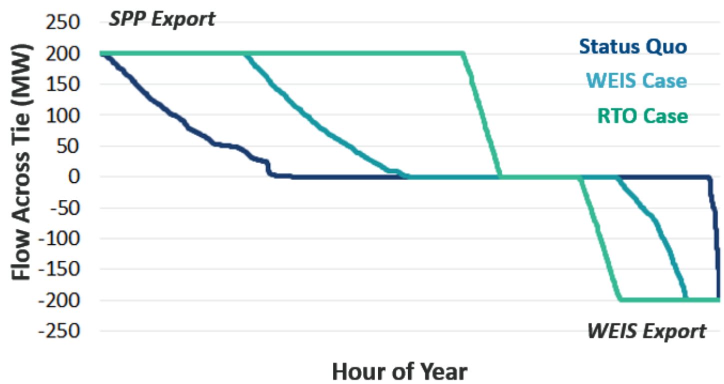


Figure 12 shows flows on the Stegall tie in the three cases. In the Status Quo Case, the majority of hours have no flows over the tie, and in the hours when the tie utilized there are more flows from the WEIS to SPP. As we move from the WEIS Case to the RTO Case, the simulated flows on the tie become increasingly responsive to price signals on either side of the tie. In the RTO Case, we see that SPP becomes a large exporter into the WEIS, with flows moving in the direction of the WECC in about 60% of hours.

FIGURE 13: RAPID CITY TIE FLOWS

Figure 13 illustrates that the portion of the Rapid City tie in the WEIS footprint demonstrates a similar pattern as the Stegall tie, as it is largely unused in the Status Quo Case but used largely for exports from SPP to WEIS in the RTO Case. Similarly, Figure 14 shows the same general pattern on the Sidney tie, with large amounts of exports from SPP to the WEIS in the RTO Case.

FIGURE 14: SIDNEY TIE FLOWS



The four figures illustrate how the flows on the DC ties help create benefits from participation in the WEIS Market and the expanded SPP RTO. In both market structures, the additional flows on the DC ties move low cost power from SPP into the WECC, which creates benefits for both the SPP members through additional sales revenue and for the WEIS members by substituting higher-cost production and by increasing sales to other areas of the WECC.

IV. Conclusions

This study estimates the benefits in production cost savings for the WEIS and SPP participants due to the creation of the WEIS Market and from the expansion of the SPP RTO market to the WEIS footprint. Benefits in this study are measured as adjusted production cost savings and additional wheeling revenues that may be generated by the formation of the RTO market. Adjusted production cost is an approximation of the cost to serve load, which we estimate in a Status Quo Case and the two market participation cases. The difference in APC between cases demonstrates how the cost to serve load will change due to market formation. Additional wheeling revenue arise in the RTO Case as the WEIS members are able to utilize each other's transmission systems and the four DC ties without incurring any wheeling fees to sell power to other entities in the WECC.

The benefits for the two market participation cases are summarized as follows:

- **WEIS Case.** Benefits in the WEIS case are derived from hurdle-free transmission between the WEIS members in the real-time cycle, economic trading across the DC ties in the real-time, and full transfer capabilities across transmission paths TOT 2A, TOT 3 and TOT 5. The WEIS Market produces APC benefits of over $16 million/year for the combined SPP and WEIS footprint (or 0.3% of total production costs). The WEIS members receive roughly $9 million/year in APC savings, and the SPP members receive about $7 million/year in APC savings. Benefits in the WEIS Case are derived mostly from increased power flows over DC ties in the real-time market. Hurdle-free transmission between the WEIS members in the real-time allows for lower-cost power from SPP to substitute higher-cost power in the WEIS footprint.

- **RTO Case.** The RTO Case produces benefits of $49 million/year for the combined SPP and WEIS footprints (0.6% of total production costs). In this case, the SPP footprint experiences $24 million/year of APC reduction while the WEIS footprint experiences $8.5 million/year in production cost savings and over $16 million/year in wheeling revenues from exports tariffs. Benefits in this case are derived from full DC tie optimization in the day-ahead and real-time, SPP and WEIS reserve sharing capabilities, hurdle-free transmission between the WEIS members in the day-ahead and real-time, and utilization of the full transmission capability in the WEIS footprint.

The benefits estimated in this study are driven by optimized dispatch across the footprints, removing inefficiencies in bilateral trading (as represented by hurdle rates in unit commitment and dispatch cycles), allowing available transmission to be co-optimized across the interconnection on the DC ties (and within footprints), and in the RTO Case, allowing the SPP and WEIS areas to co-service reserves obligations. These simulations are likely a conservative estimation of market benefits, because the simulations do not estimate additional benefits from market participation, including market benefits associated with management of intra-hourly deviations for variable resources, uncertainty in load or renewables, generation or transmission outages, inefficiencies of bilateral trading, or potential reductions in operating reserve requirements, among others.

EXHIBIT ACL-10

2028 LG&E-KU Hourly Demand Forecast

(Excel File Provided Separately)