2022 RTO Membership Analysis

PPL companies

November 2022

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)

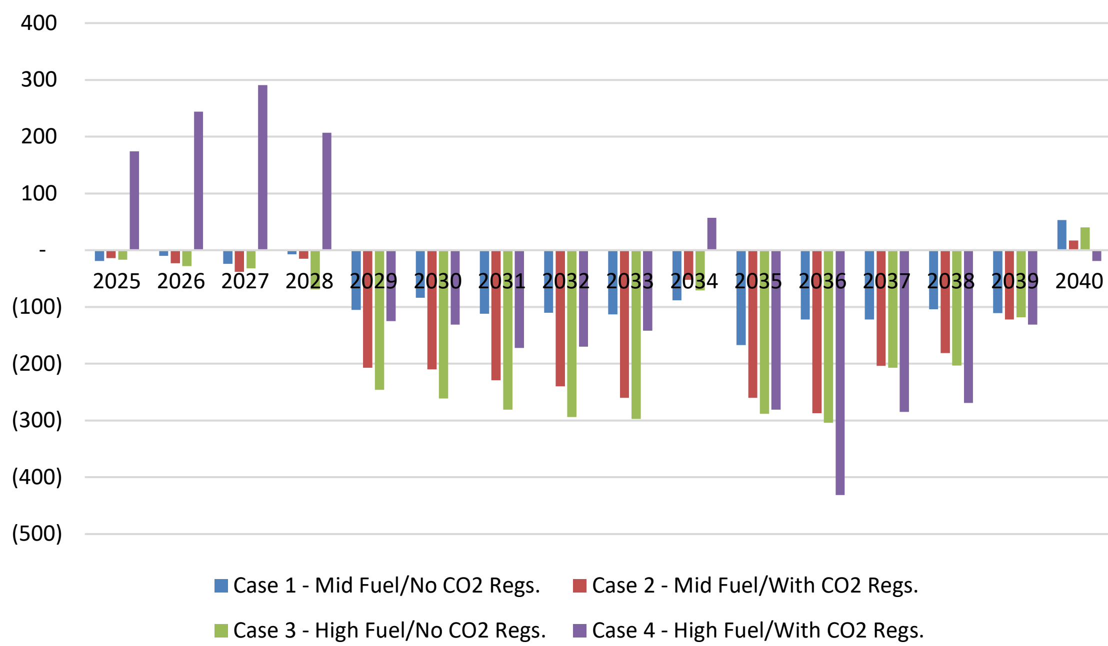

Figure 1 reflects that PJM membership offers the potential benefit of increased energy sales into PJM in the early years when the Companies are longer on capacity, especially in Case 4, which assumes high fuel prices and national CO_2 reduction regulations. But in Cases 1-3, PJM's fixed costs exceed 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	(1,246)	(2,327)	(2,675)	(1,183)
2022 PV Dollars	(620)	(1,165)	(1,365)	(272)

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

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[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

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[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.

<u>Internal Cost of RTO Membership ("LG&E/KU Internal Implementation")</u>
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.

<u>Lost Transmission Revenue ("LG&E/KU Lost Transmission Revenue")</u>
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.

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

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.

RTO Energy Market Benefits or Costs ("PJM Energy Market Benefits/(Costs)")

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.

[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	132	(14)
2029	205	149	56
2030	200	144	56
2031	195	139	55
2032	190	135	54
2033	200	152	48
2034	293	354	(61)
2035	409	437	(27)
2036	623	515	108
2037	742	669	73
2038	834	739	95
2039	925	926	(1)
2040	1,155	938	218

<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 most 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 most 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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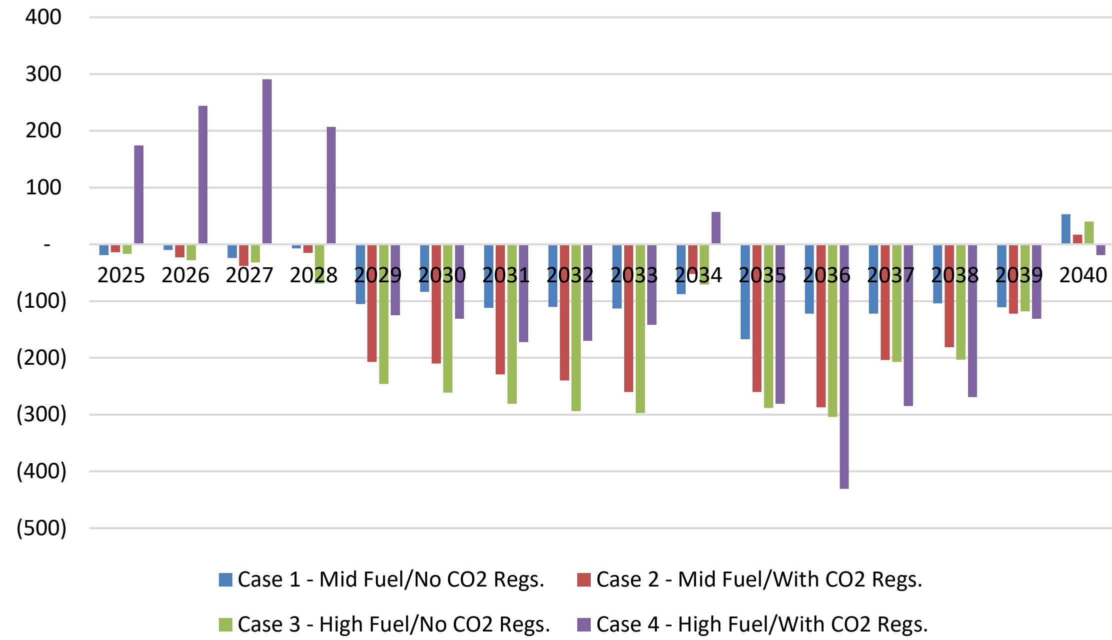
[26] The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO. *See*, *E.ON U.S., LLC, et al.*, Docket No. 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.

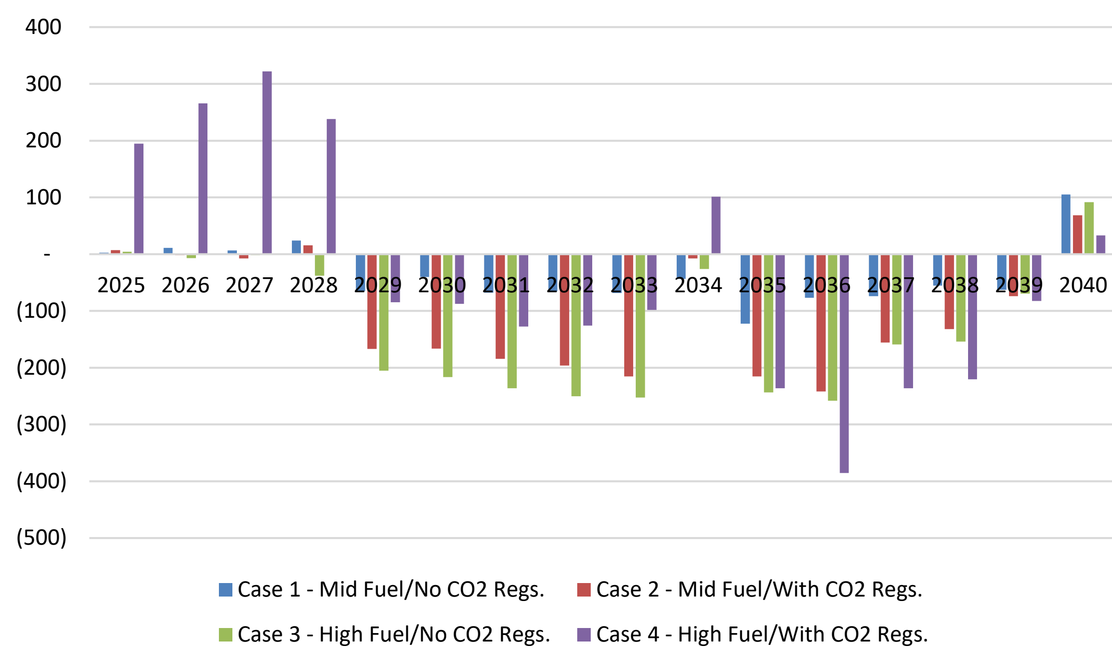
[27] This assumption weighs the benefit to joining the RTO higher but is reasonable in lieu of a FERC order providing direction in this area, as it is based on the current approved approach to pancaked rates at the MISO-PJM seam. FERC has required that transmission across the MISO-PJM be depancaked through 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	3	7	4	195
2026	11	(2)	(7)	265
2027	7	(7)	(2)	322
2028	24	16	(38)	238
2029	(65)	(167)	(205)	(85)
2030	(40)	(166)	(217)	(87)
2031	(67)	(185)	(236)	(128)
2032	(66)	(196)	(250)	(125)
2033	(69)	(215)	(252)	(98)
2034	(43)	(7)	(26)	101
2035	(123)	(215)	(243)	(236)
2036	(77)	(242)	(258)	(385)
2037	(74)	(156)	(159)	(236)
2038	(56)	(132)	(154)	(220)
2039	(63)	(74)	(69)	(82)
2040	105	69	92	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	(1,246)	(2,327)	(2,675)	(1,183)
2022 PV Dollars	(620)	(1,165)	(1,365)	(272)

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

	Case 1	Case 2	Case 3	Case 4
Nominal	(592)	(1,673)	(2,021)	(529)
2022 PV Dollars	(286)	(832)	(1,032)	61

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 be net beneficial for customers only in Case 4, and only nominally so: on average, less than $4 million of net present value benefit per year. In all other cases studied, PJM's energy and capacity impacts alone would result in net present value *costs* to customers ranging from $286 million to over $1 billion, far exceeding the net benefits of Case 4. Moreover, Case 4 is the *least* likely scenario studied because it assumes high fuel prices persist and significant CO_2 emission regulations are in place *every year* from 2025 through 2040 even though CO_2 emission regulations would tend to reduce the demand for fossil fuels, making persistent high fossil fuel prices less likely (barring long-term supply constraints). Thus, a scenario that falls between or is a combination of Cases 1, 2, and 3 appears more plausible, 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]

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[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

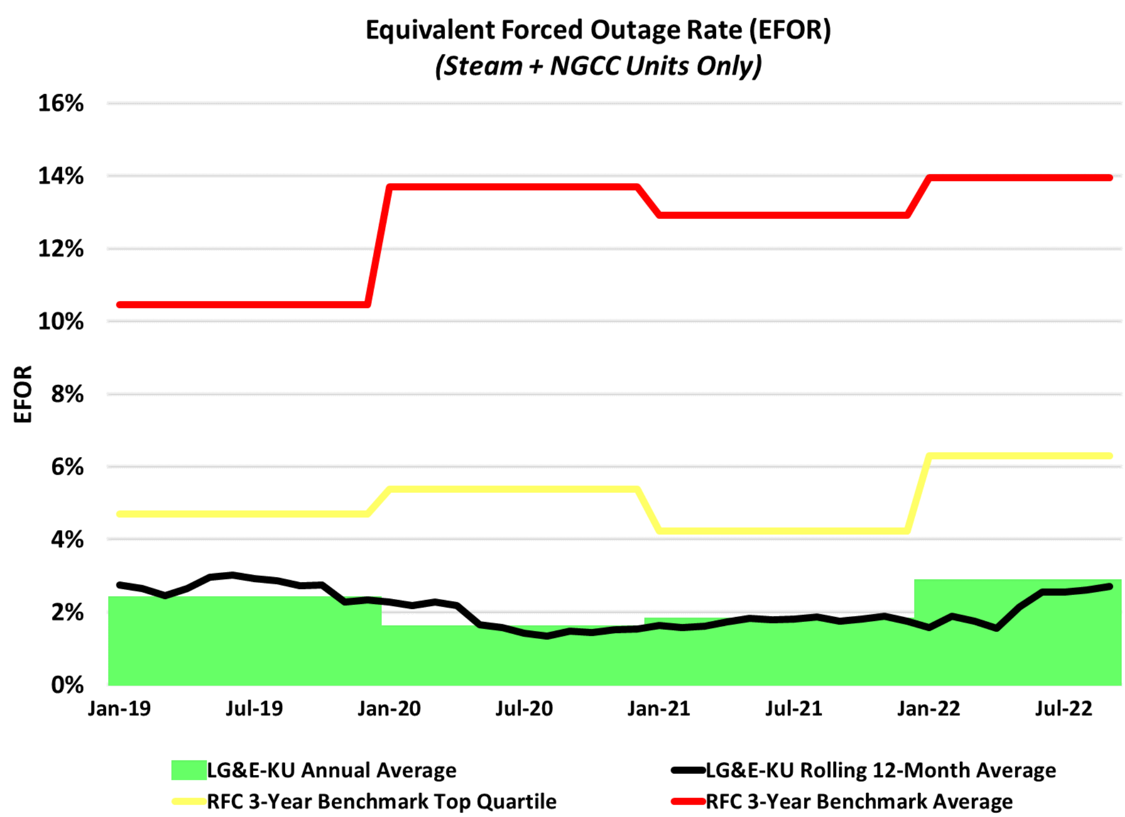
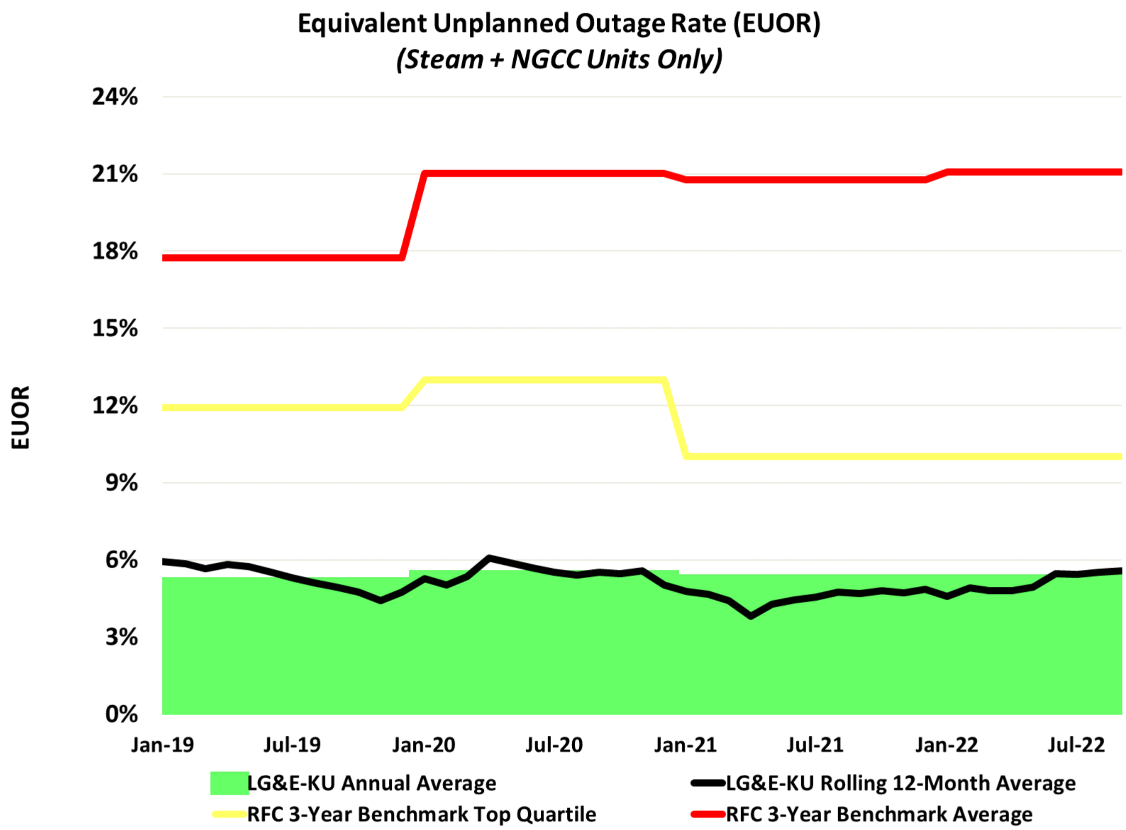


Figure 5 - Equivalent Unplanned Outage Rate



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	-13.7	55.5	56.4	55.3	54.2	48.3	-60.7	-27.1	108.2	72.7	95.1	-0.9	217.8
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**	**44.3**	**-53.1**	**-32.3**	**-59.3**	**-57.6**	**-60.4**	**-35.2**	**-114.3**	**-68.4**	**-65.6**	**-47.2**	**-54.1**	**113.4**

Net Benefits/(Costs)	**-18.6**	**-10.2**	**-24.0**	**-6.9**	**-105.2**	**-84.3**	**-111.7**	**-109.8**	**-113.1**	**-88.1**	**-167.2**	**-122.2**	**-122.4**	**-104.3**	**-111.1**	**52.9**

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	-13.7	55.5	56.4	55.3	54.2	48.3	-60.7	-27.1	108.2	72.7	95.1	-0.9	217.8
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**	**36.0**	**-154.9**	**-158.2**	**-176.5**	**-188.0**	**-207.1**	**0.9**	**-207.2**	**-233.5**	**-147.4**	**-123.6**	**-65.4**	**77.1**

Net Benefits/(Costs)	**-14.4**	**-23.5**	**-38.1**	**-15.3**	**-207.0**	**-210.2**	**-228.8**	**-240.2**	**-259.8**	**-52.0**	**-260.1**	**-287.3**	**-204.2**	**-180.7**	**-122.3**	**16.6**

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	-13.7	55.5	56.4	55.3	54.2	48.3	-60.7	-27.1	108.2	72.7	95.1	-0.9	217.8
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**	**-17.3**	**-193.4**	**-208.5**	**-228.3**	**-242.3**	**-244.1**	**-17.8**	**-235.2**	**-249.8**	**-150.7**	**-145.8**	**-60.9**	**100.3**

Net Benefits/(Costs)	**-17.2**	**-28.3**	**-32.4**	**-68.6**	**-245.5**	**-260.5**	**-280.7**	**-294.5**	**-296.8**	**-70.7**	**-288.1**	**-303.6**	**-207.5**	**-202.8**	**-117.9**	**39.8**

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)	194.7	265.3	306.3	251.8	-140.1	-143.7	-182.9	-179.6	-146.2	162.0	-208.8	-493.6	-309.1	-315.2	-81.4	-184.9
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	-13.7	55.5	56.4	55.3	54.2	48.3	-60.7	-27.1	108.2	72.7	95.1	-0.9	217.8
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
	223.4	**294.7**	**341.8**	**258.5**	**-72.6**	**-79.3**	**-119.5**	**-117.3**	**-89.7**	**109.5**	**-227.7**	**-377.1**	**-228.1**	**-211.8**	**-73.9**	**41.3**

Net Benefits/(Costs)	**173.5**	**243.9**	**291.1**	**207.2**	**-124.7**	**-131.4**	**-171.8**	**-169.5**	**-142.4**	**56.6**	**-280.6**	**-430.9**	**-284.9**	**-268.9**	**-130.8**	**-19.2**

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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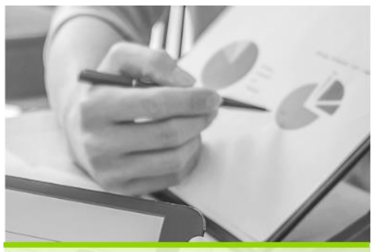

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Our Solutions Evolve Around the Energy Cloud. These solutions focus your most pressing needs to help you thrive in the rapidly changing environment.

- Analytics
- Customer Programs
- Energy System Transformation
- Modern Pricing Platform
- Building & Appliance Technologies
- Decarbonization
- Generation Services
- Risk, Compliance, and Security

- Capital/Asset Investment Planning
- Energy Transition Financing
- Mobility
- Transmission Services
- Utility C&I Revenue Growth
- Utility Flexibility Program
- Utility Resource Transformation

Exhibit 1

Guidehouse

Core Capabilities. Our core capabilities support our solution offerings and organized through Communities of Practice.

ENERGY

SUSTAINABILITY

INFRASTRUCTURE

- ✓ Market Research
- ✓ Organizational Transformation
- ✓ Carbon Pricing Design
- ✓ Customer Engagement Solutions
- ✓ Data Analytics & Modeling
- ✓ Design Thinking
- ✓ Energy Systems Modernization
- ✓ Enterprise Risk Management & Security
- ✓ Emerging Technology Program Support
- ✓ Generation Strategy & Advisory
- ✓ R&D Program Planning & Evaluation
- ✓ Corporate Climate Plan Advisory
- ✓ Policy & Regulation Advisory
- ✓ Utility Strategy Development
- ✓ Regulatory Support Services
- ✓ Renewables Integration
- ✓ Clean Energy Programs Design & Evaluation
- ✓ Procurement Strategy Planning
- ✓ Large-Scale Program Management
- ✓ Wholesale Market Analysis

Exhibit 2

Guidehouse

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

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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

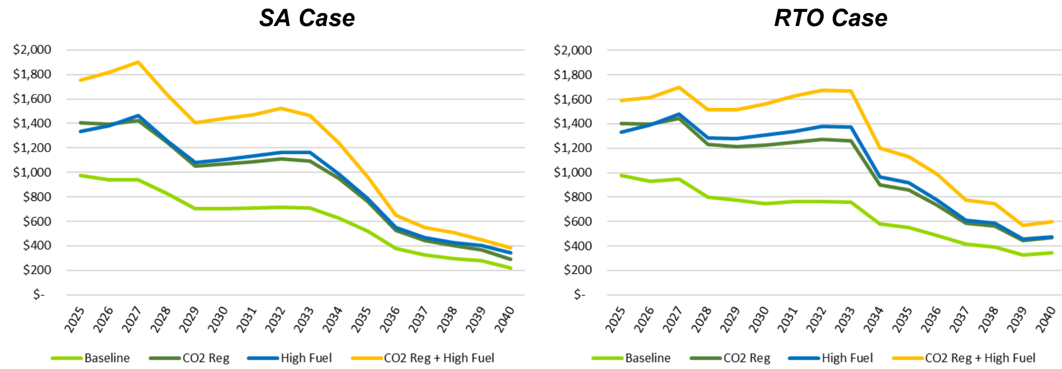
The benefits and costs to LG&E/KU customers of each alternative were evaluated by comparing a business-as-usual or status-quo case to a case in which LG&E / KU joins PJM. Given the complexity of obtaining necessary approvals and preparing for full operational integration for these alternatives, the study 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)

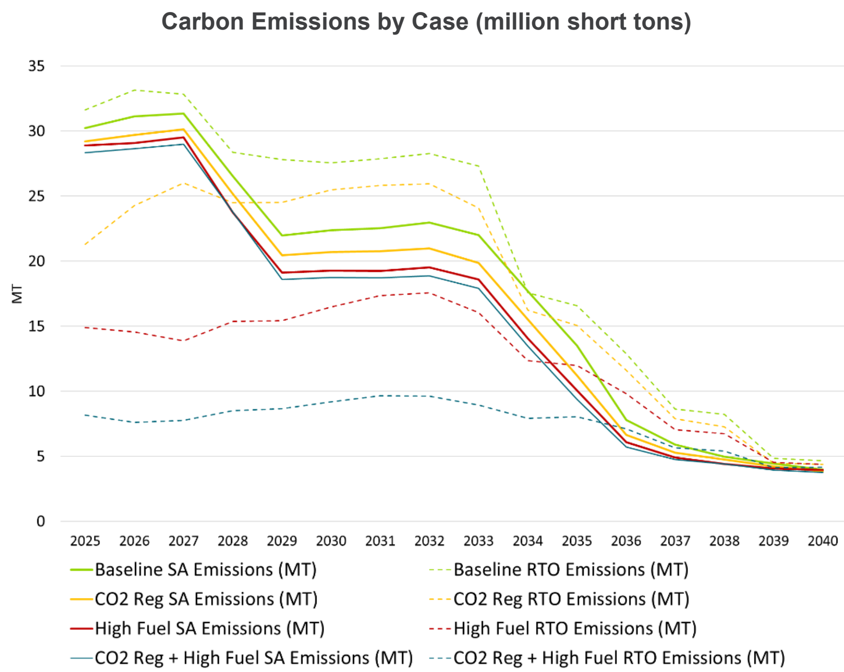


Generation, Imports, and Exports

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.

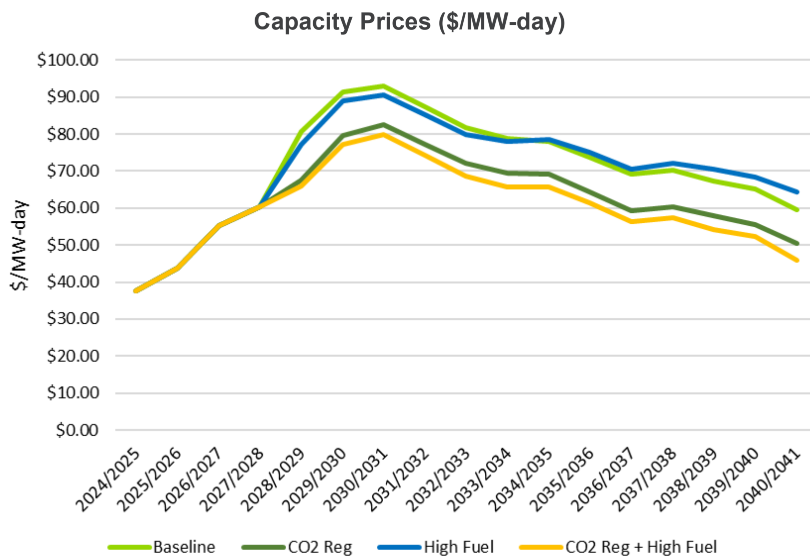
Carbon Emissions

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)
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/MW-day
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.*

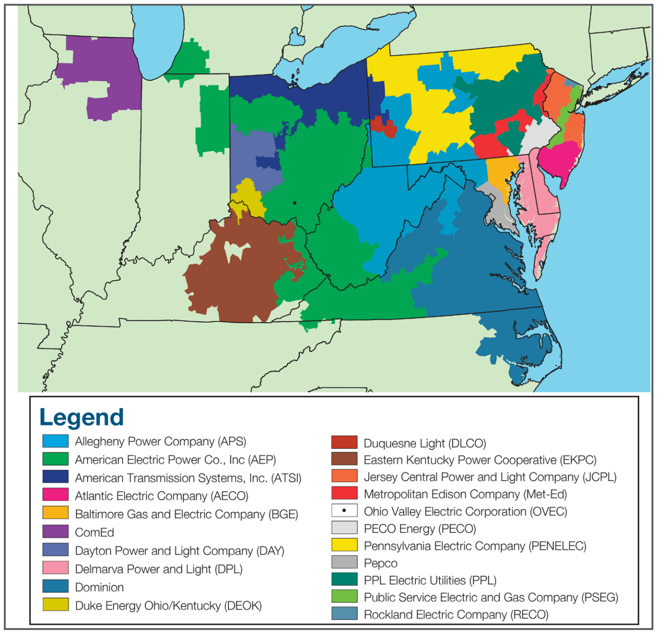
Market Feature	Summary of PJM
Ancillary Services	Three markets for ancillary services: regulation and reserve markets are optimized with the energy market simultaneously to minimize costs to the grid and are cleared on a real-time basis; day-ahead scheduling reserve market obtains supplemental 30-minute 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



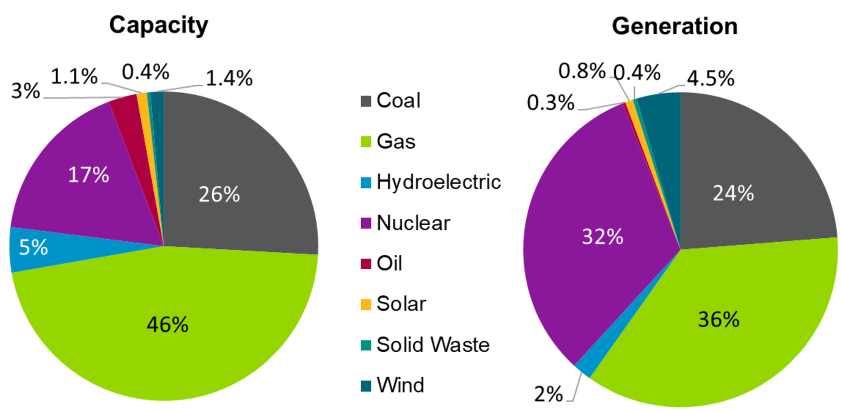
Source: PJM

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)

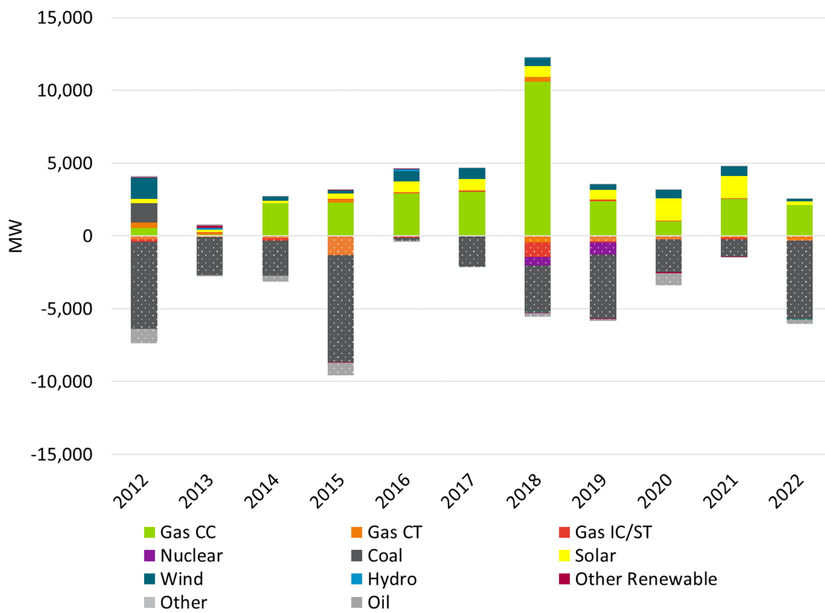
Over 70% of PJM's current coal fleet is over 40 years old, just under 90% of installed natural gas energy capacity was built after 1990. New natural gas capacity is comprised of CC units and CCGT peakers. PJM's entire wind and solar fleet was built after 1990.

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.

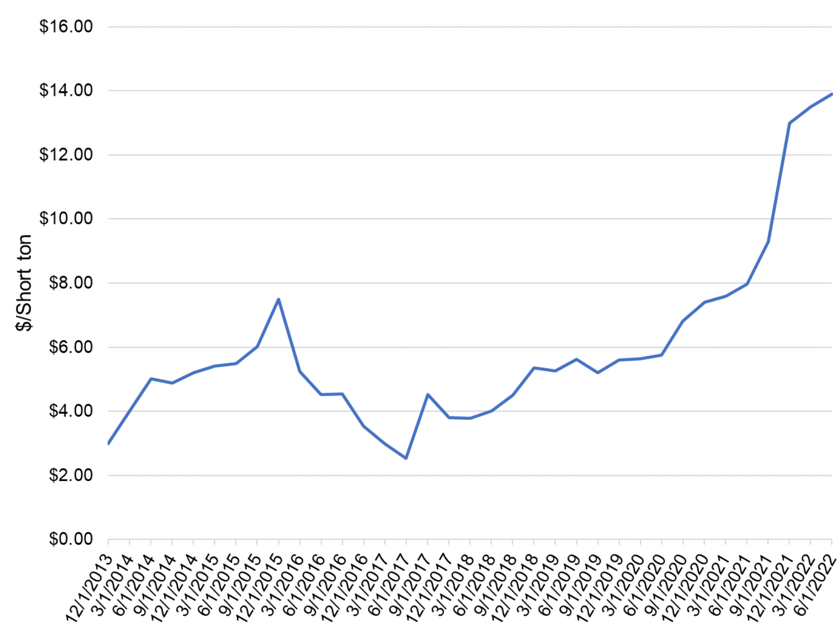
1.2.3.2 Regional Greenhouse Gas Initiative

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

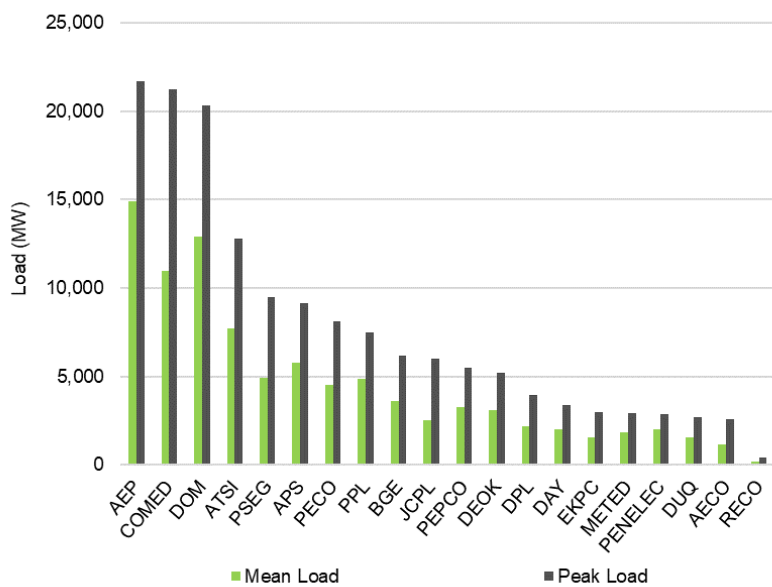
The economic impact of RGGI on affected fossil fuel generators will be the added cost of the CO_2 allowances to the energy production (bid) cost of these generators. The estimated impacts of the RGGI program on generation resources have been minimal to date, and the cost to consumers has been offset 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)



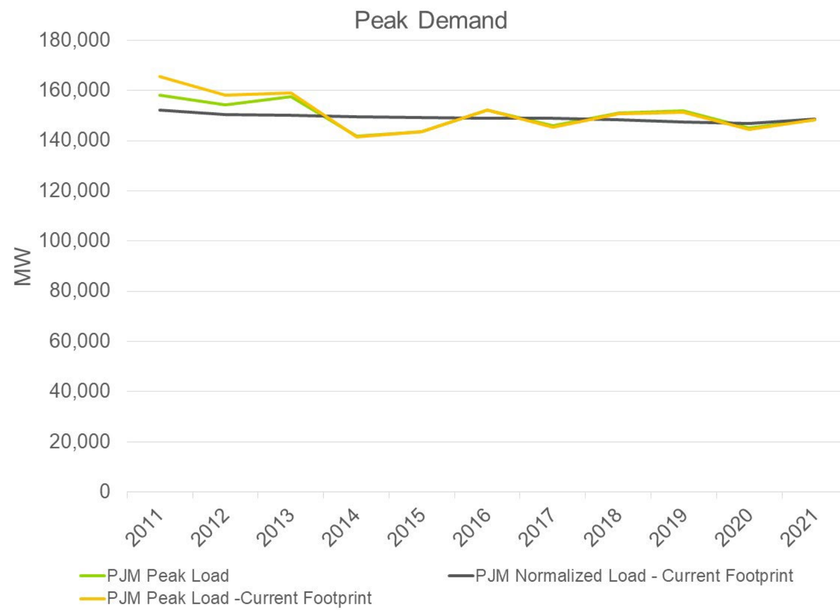
Source: Guidehouse (Data from Energy Velocity, retrieved July 2022)

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)

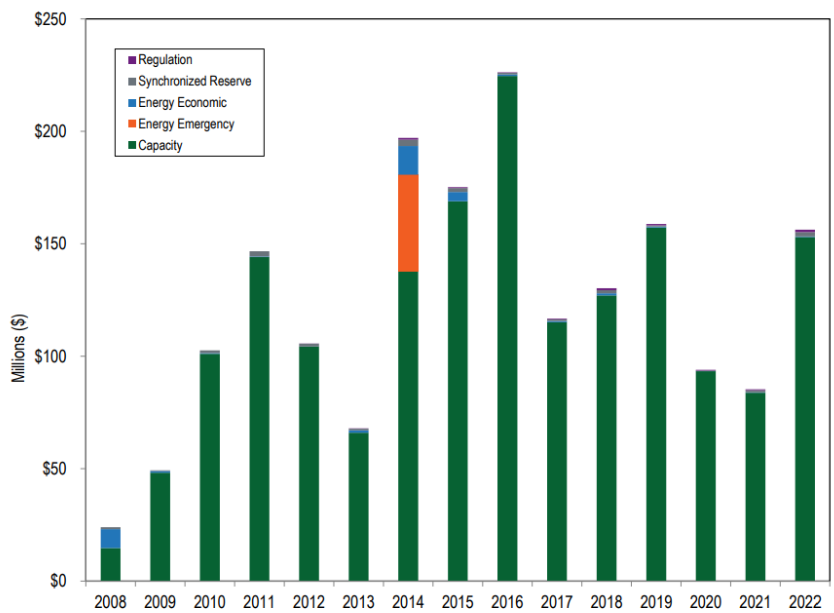
Flat load growth has been driven by energy efficiency in the recent years. PJM's 2022 Load Forecast Report projects 0.4% annual average growth for peak load and 0.8% annual average growth for net energy over the next 10 years for the whole RTO. [5]

[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]

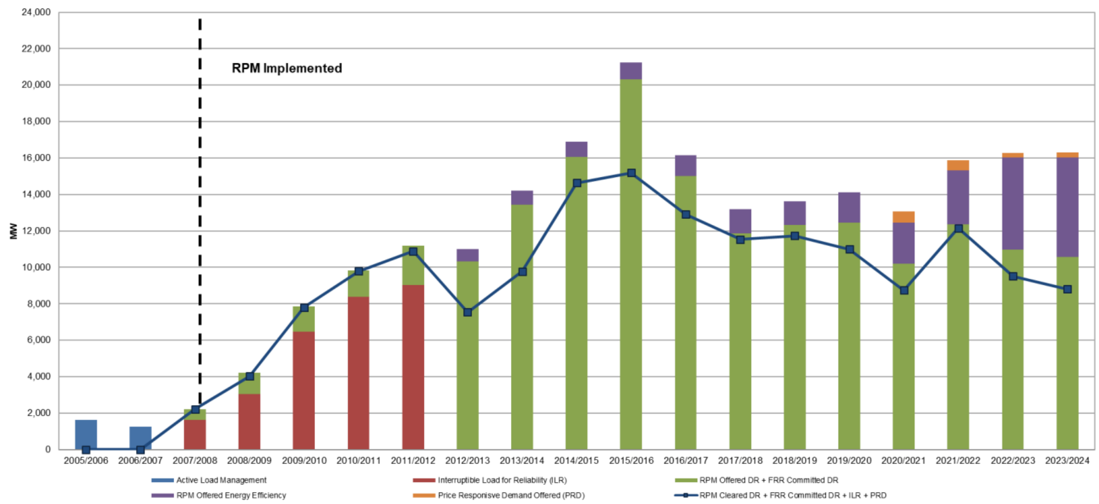


Source: PJM State of the Market Report 2022 Q1

[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.

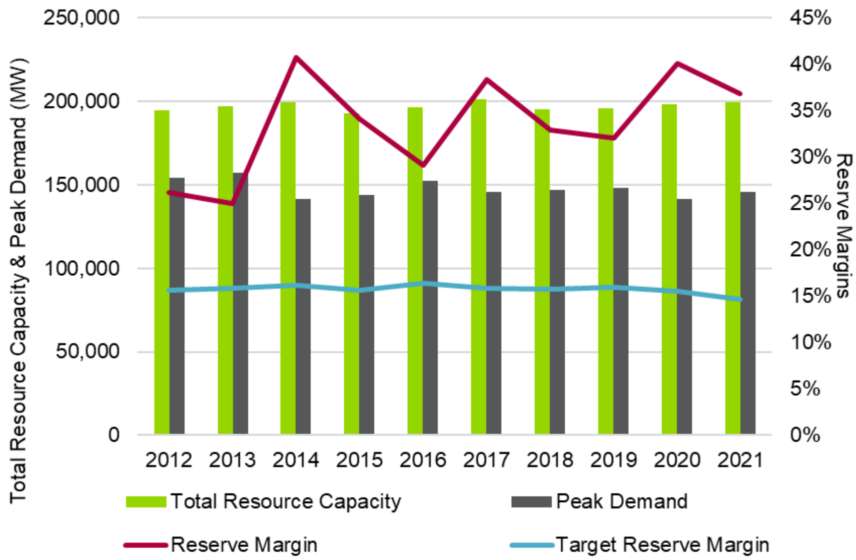
1.4 Demand and Supply Balance

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



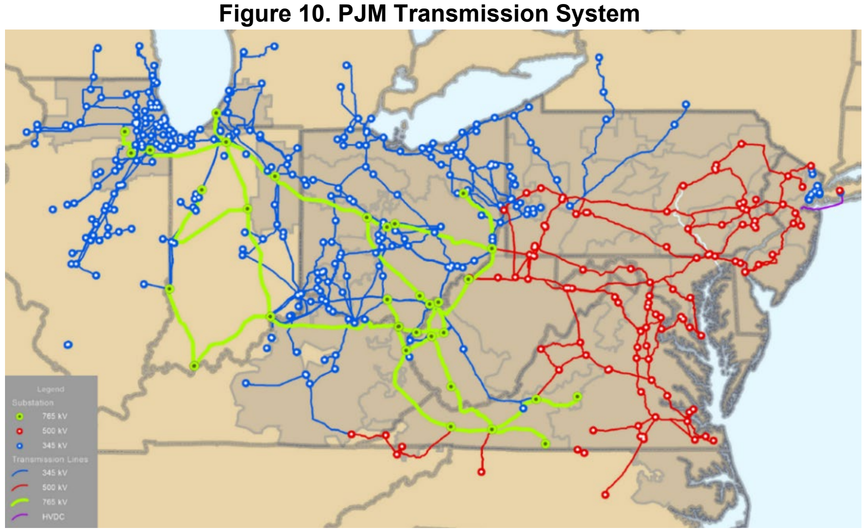
Source: Guidehouse (data from PJM State of the Market Reports)

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.

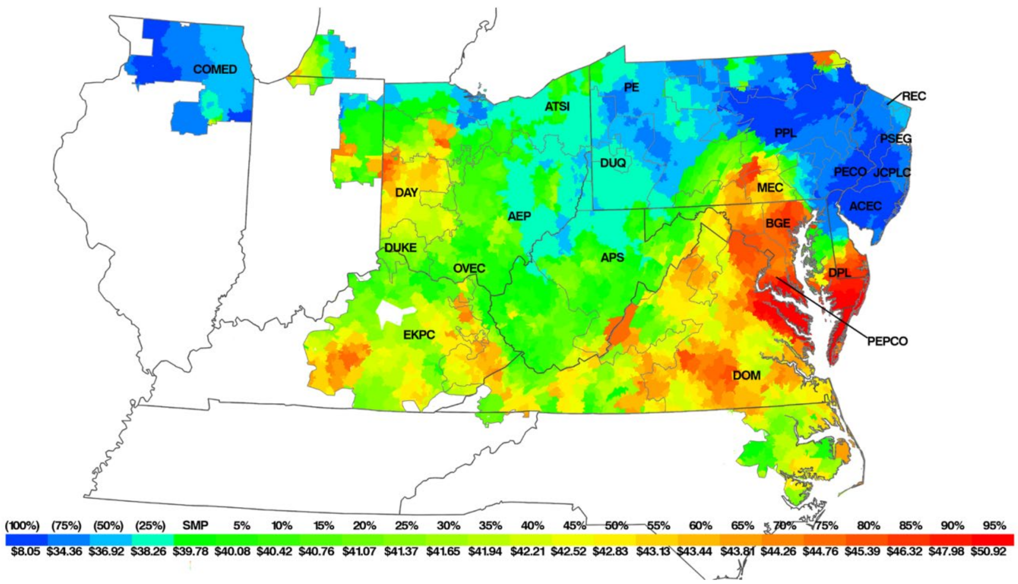
Figure 10. PJM Transmission System



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

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[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

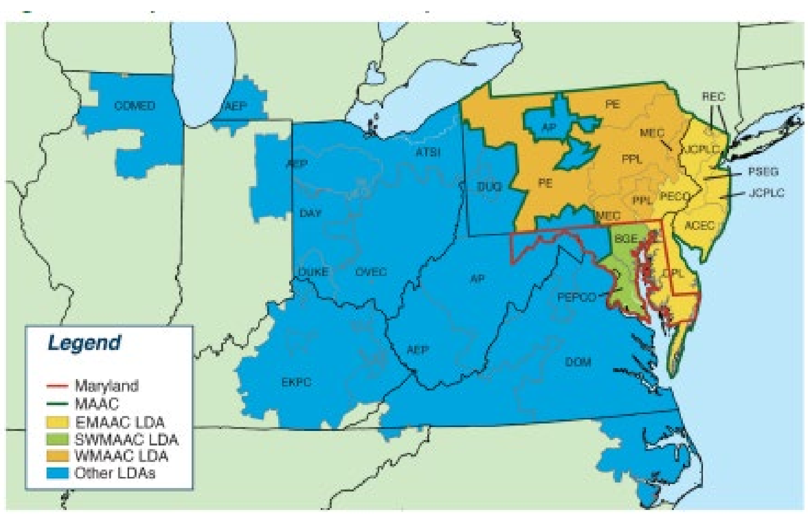
In total, nearly 145 GW of unforced capacity cleared in the most recent auction, representing a 21.6% reserve margin for the delivery year. 3,734.5 MW of new generation capacity cleared the BRA this auction.

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)

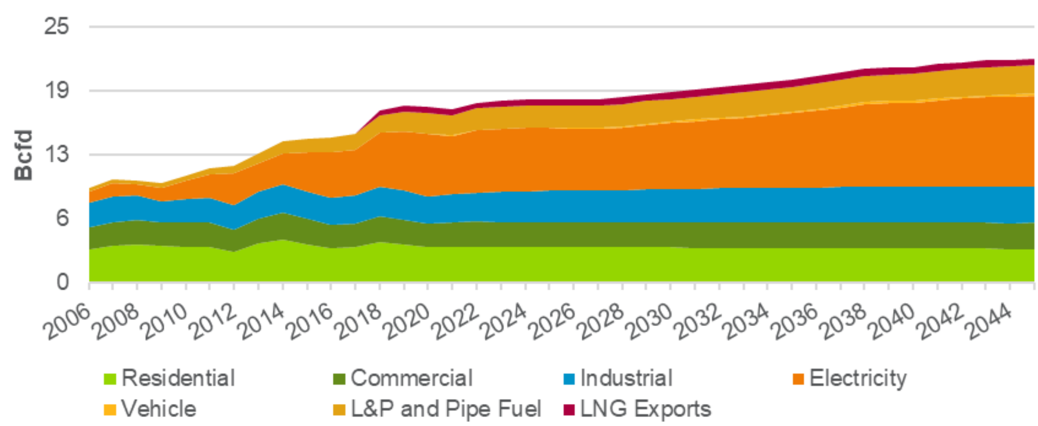
1.7 Fuels

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



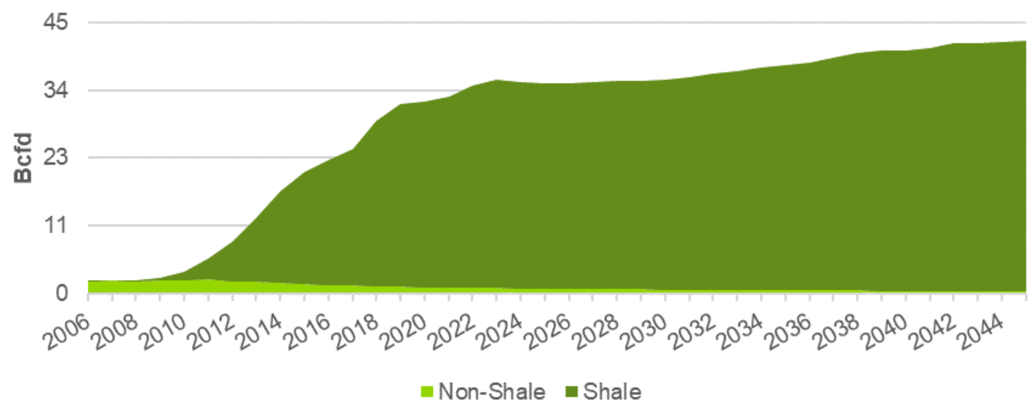
Source: Guidehouse's North America Natural Gas Market Outlook, Spring 2022; RBAC

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

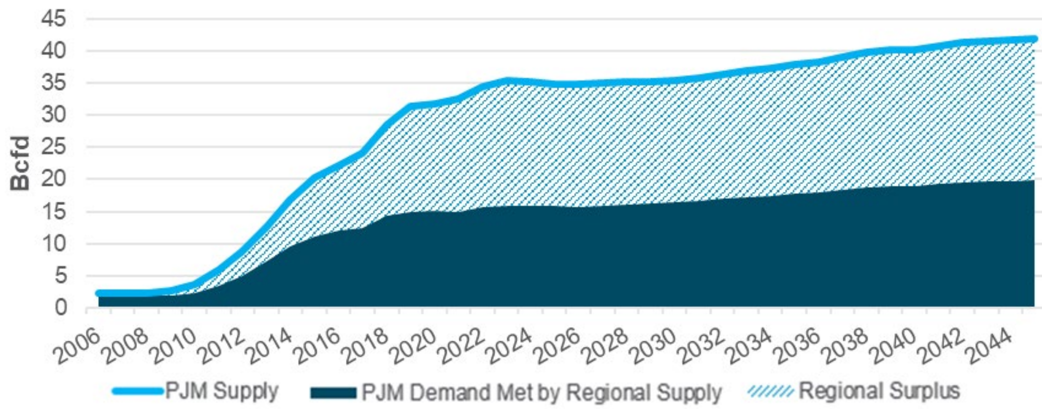
Due to the increasing levels of production from the Marcellus and Utica shale plays, PJM now exports surplus gas to surrounding regions. Several pipeline projects have recently come online, including the 3.25 Bcfd Rover Pipeline project, the largest pipeline project in the area, to move surplus gas to 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.

Exhibit 2

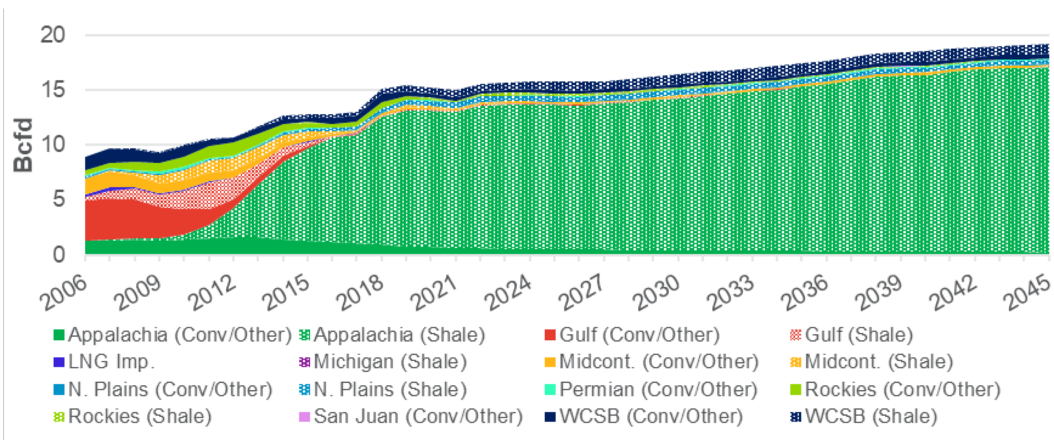
Figure 15: PJM Regional Gas Balance



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

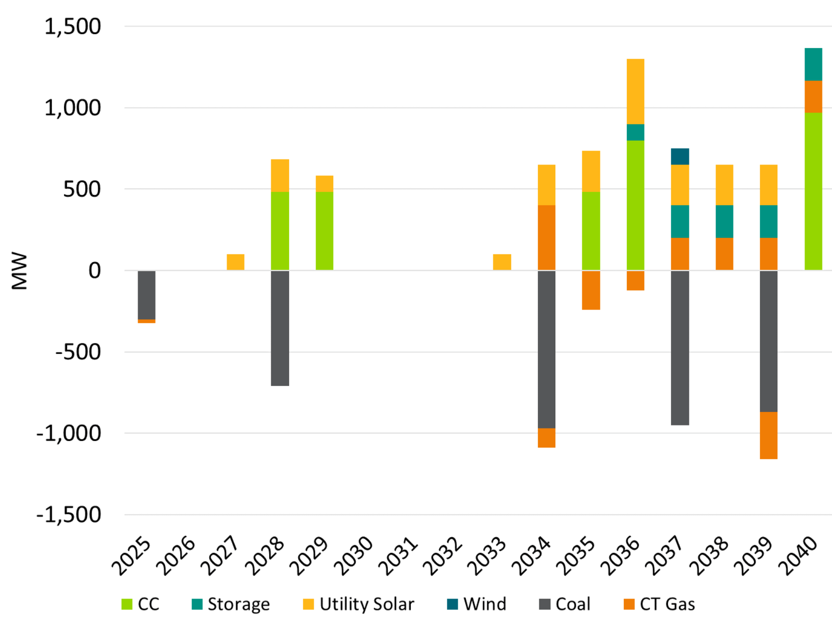
	Summer	Winter
Solar	79%	0%
Wind	24%	32%

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.

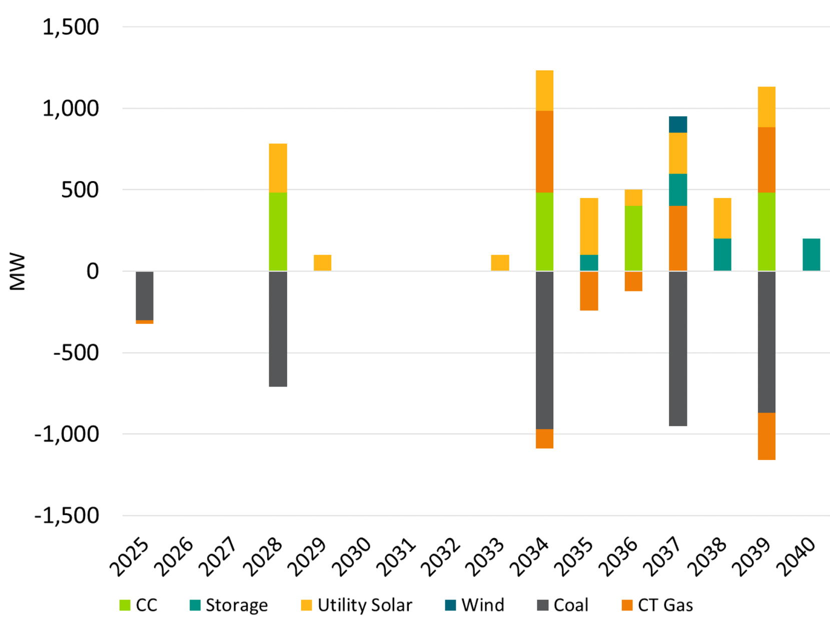
LG&E / KU forecasts a peak load coincidence factor of 92% based on historical peak load coincidence vs PJM peak loads. The recommended FPR in PJM is 1.0918. This puts the annual LG&E / KU capacity requirements on an unforced capacity basis equal to:

$$(\text{Peak Demand}) * (92\%) * (1.0918)$$

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

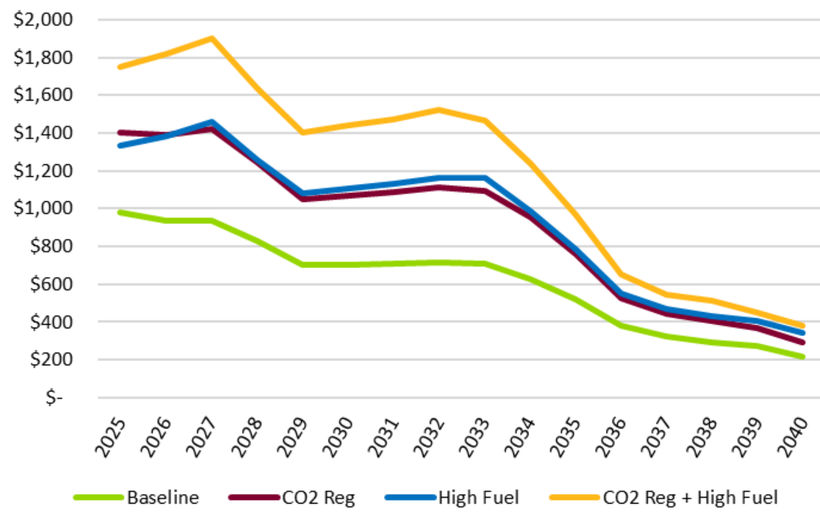
4.1.1 Adjusted Production Cost Impacts

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.

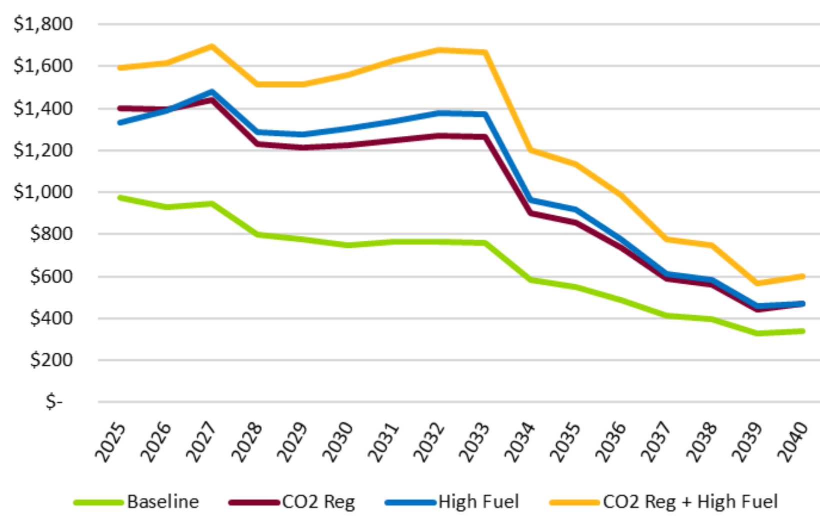
SA Case

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)

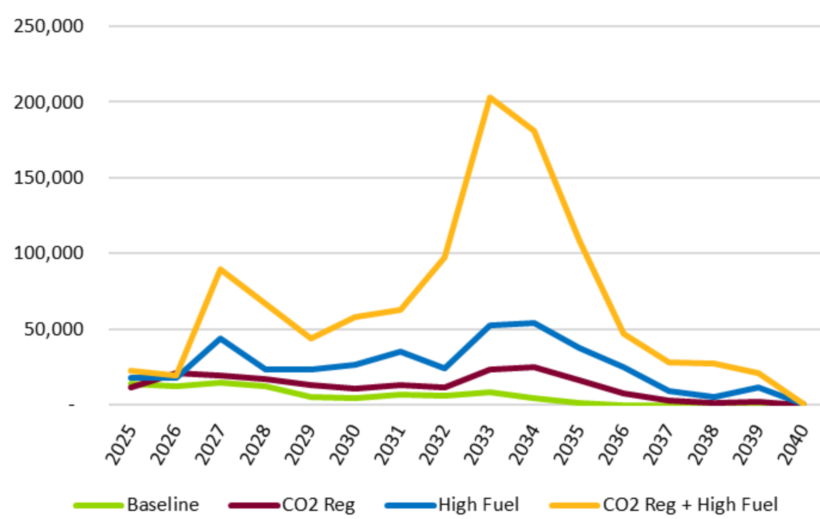
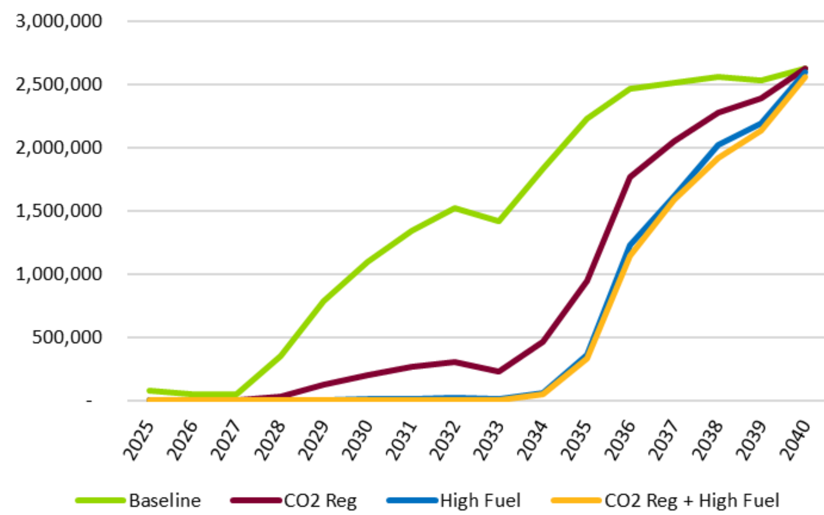


Figure 22. Standalone Exports (MWh)



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)

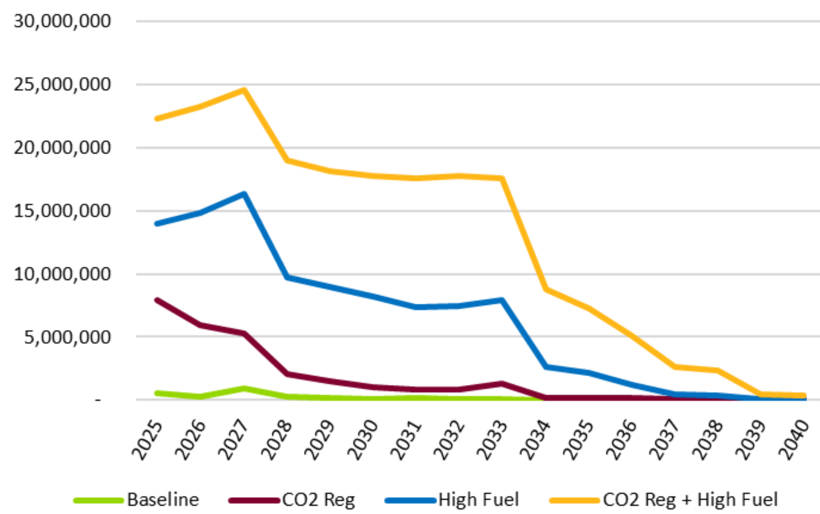
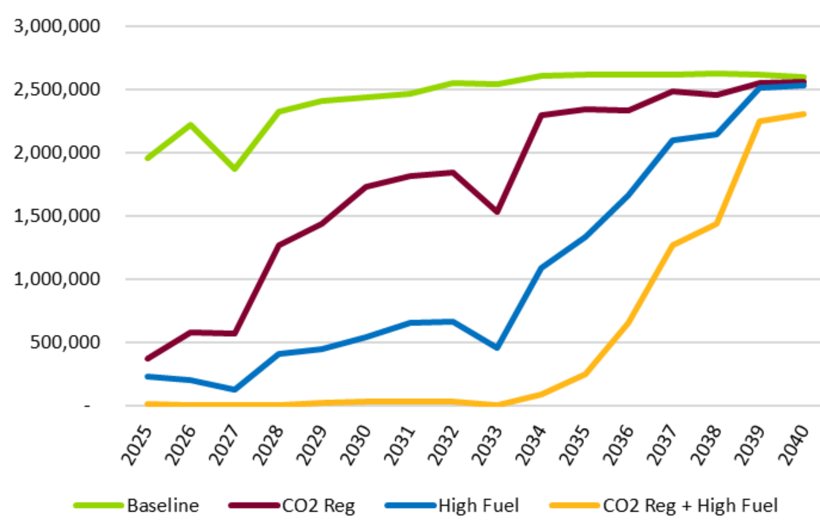


Figure 24. RTO Exports (MWh)



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)

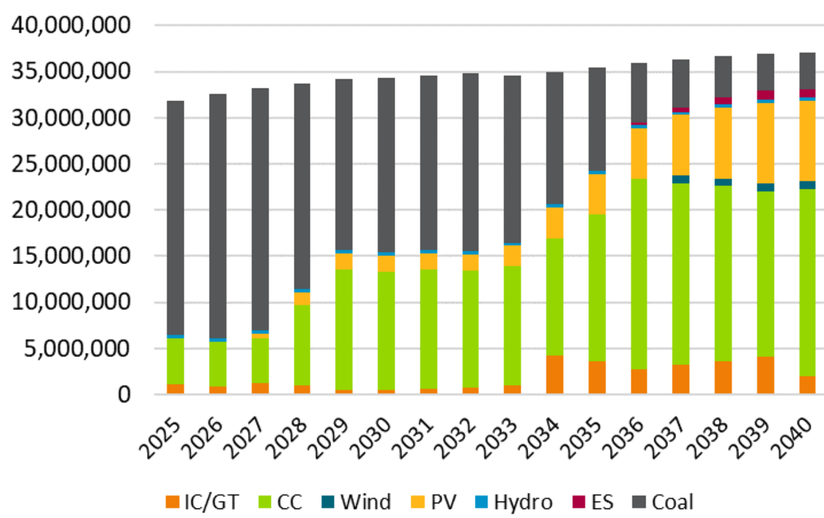


Figure 26. Case 2 SA - Generation by Unit Type (MWh)

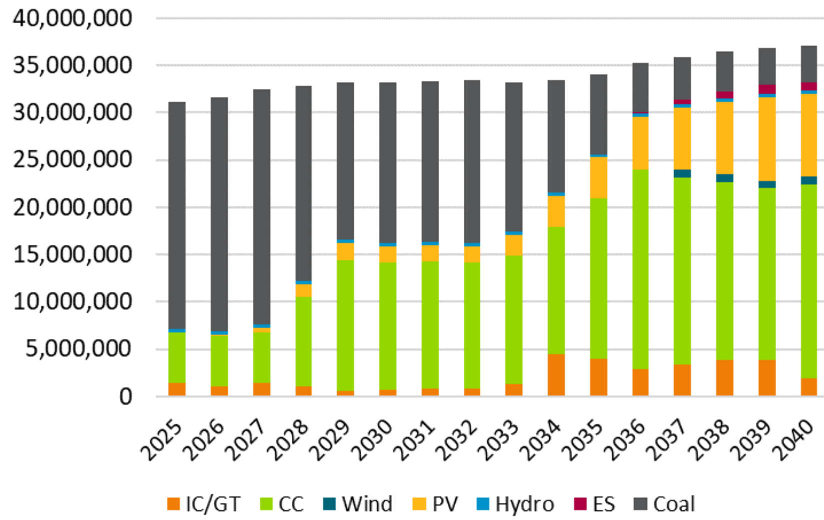


Figure 27. Case 3 SA - Generation by Unit Type (MWh)

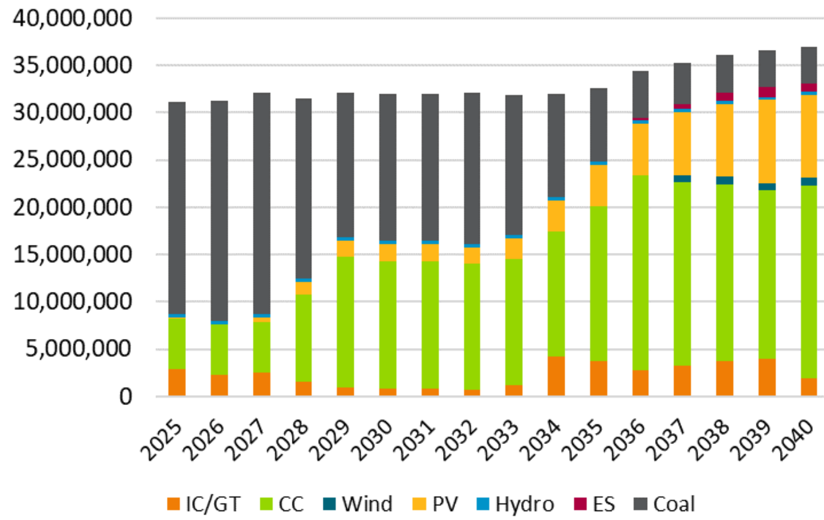
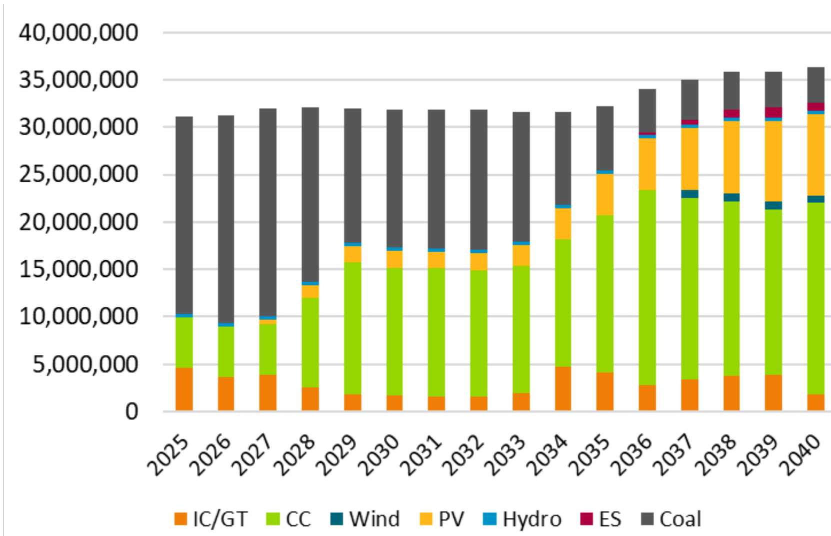


Figure 28. Case 4 SA - Generation by Unit Type (MWh)



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)

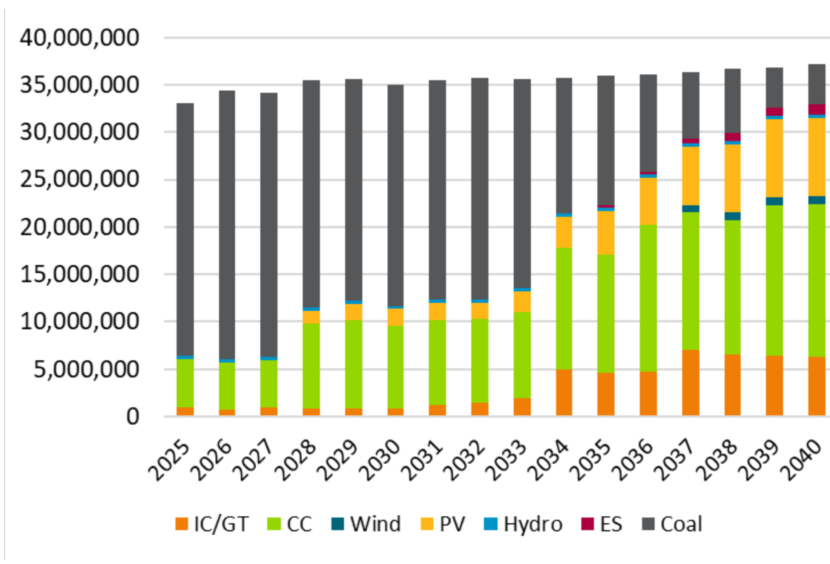


Figure 30. Case 2 RTO - Generation by Unit Type (MWh)

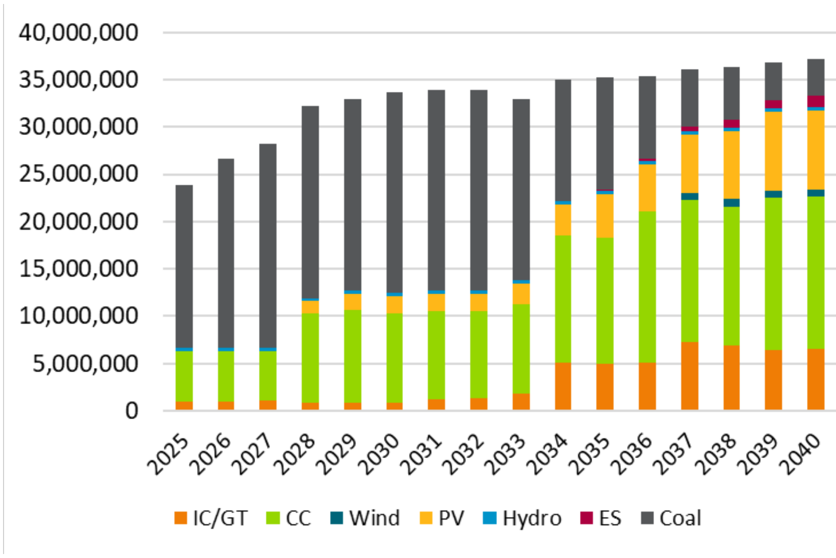


Figure 31. Case 3 RTO - Generation by Unit Type (MWh)

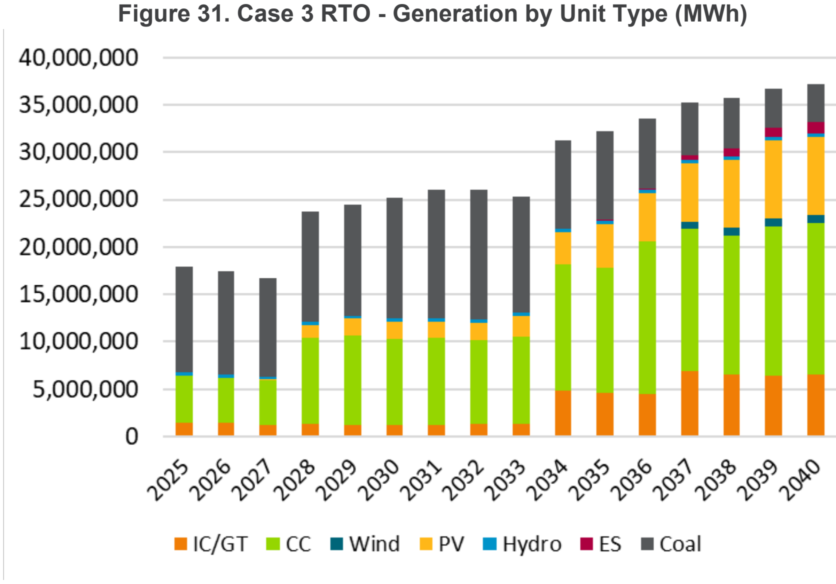
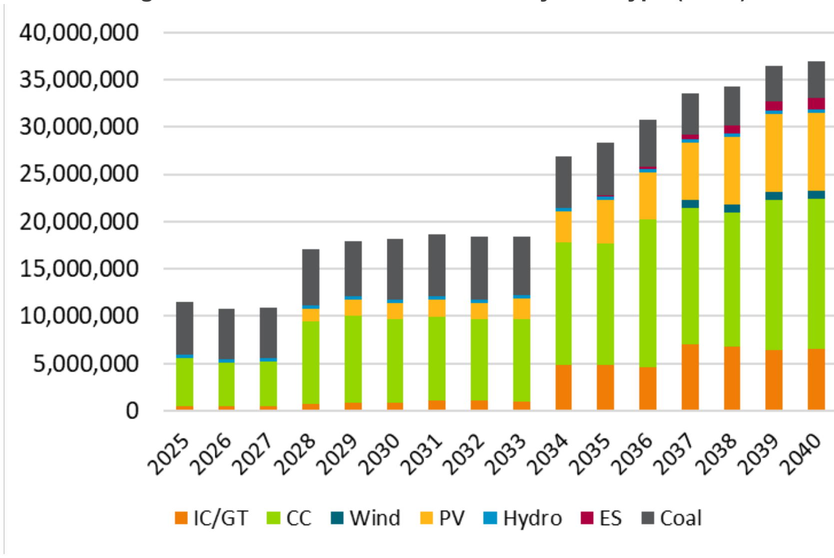


Figure 32. Case 4 RTO - Generation by Unit Type (MWh)



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.

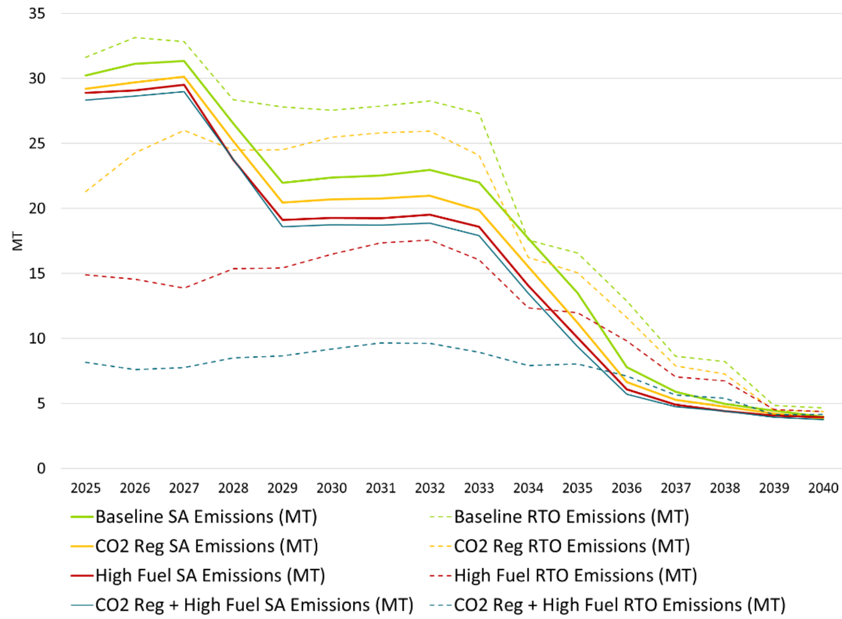
Case 1, representing baseline markets, has the highest emissions in both the SA and the RTO cases, followed by Case 2 (emissions reductions with base fuel prices), Case 3 (no emissions reductions and high fuel prices), and Case 4 (emissions reductions with high fuel prices), which has the lowest emissions 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.

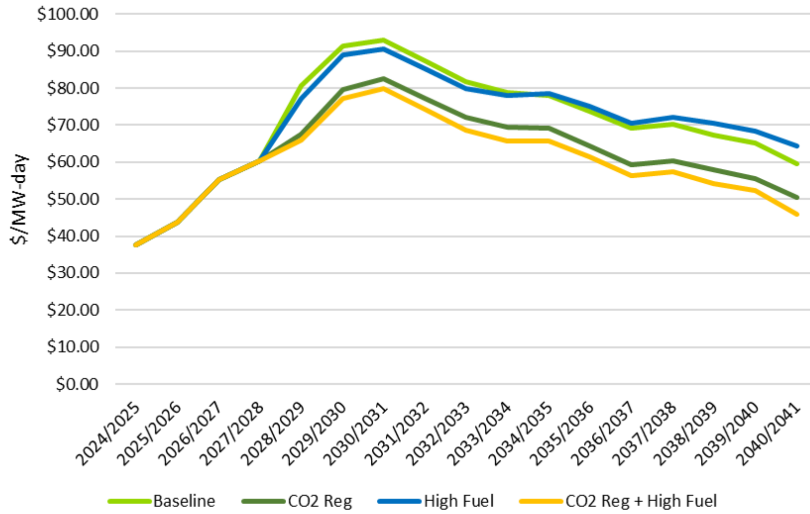
The high fuel prices somewhat affect the results, however the Net CONE is based on modern CC's which are frequently operating lower than the marginal system cost. The high fuel prices and efficient CC operations largely offset with respect to capacity prices.

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)



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							

	11	[redacted]
	12	
2028	1	
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	10	
	11	
	12	
2029	1	
	2	
	3	
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	9	
	10	
	11	
	12	
2030	1	
	2	
	3	
	4	
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	10	
	11	
	12	
2031	1	
	2	
	3	

CONFIDENTIAL INFORMATION REDACTED

Exhibit 2

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	4	
	5	
2033	6	
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	10	
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	12	
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	3	
2034	4	
	5	
	6	
	7	
	8	

	9	[redacted]
	10	
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2035	1	
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2036	1	
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2037	1	
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	12	
2038	1	

Exhibit 2

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2039	6	
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2040	6	
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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							

2028	1	[redacted]
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	12	
2029	1	
	2	
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	2	
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	10	
	11	
	12	
2031	1	
	2	
	3	
	4	
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Exhibit 2

	6	[redacted]
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	12	
2032	1	
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2035	1	
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	11	
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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	

	4	[redacted]
	5	
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	9	
	10	
	11	
	12	
2039	1	
	2	
	3	
	4	
	5	
	6	
	7	
	8	
	9	
	10	
	11	
	12	
2040	1	
	2	
	3	
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	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

Exhibit 2

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)
			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	$1.65	$3.18	$974
2026	$36.94	33,155,652	$1,225	35,080,117	$1,288	$992	$296	296,008	2,220,473	$3.02	$1.79	$929
2027	$38.03	34,025,754	$1,294	34,989,561	$1,318	$969	$348	909,217	1,873,023	$3.74	$1.76	$946
2028	$36.08	34,075,501	$1,229	36,130,379	$1,291	$862	$429	268,802	2,323,680	$25.11	$11.74	$800
2029	$35.55	33,920,099	$1,206	36,185,124	$1,277	$846	$431	149,169	2,414,194	$0.43	$25.02	$775
2030	$34.72	33,233,481	$1,154	35,594,820	$1,230	$824	$405	81,125	2,442,465	$0.38	$34.18	$748
2031	$36.36	33,768,873	$1,228	36,094,634	$1,304	$840	$464	144,101	2,469,862	$0.59	$41.71	$764
2032	$36.85	33,827,370	$1,246	36,339,562	$1,333	$848	$484	43,373	2,555,565	$3.07	$47.66	$762
2033	$39.16	33,717,105	$1,320	36,218,402	$1,412	$848	$564	36,978	2,538,275	$12.17	$45.97	$757
2034	$31.79	33,675,259	$1,071	36,275,068	$1,147	$657	$490	4,547	2,604,356	$0.95	$54.46	$581
2035	$30.16	33,675,950	$1,016	36,288,089	$1,087	$620	$467	1,610	2,613,749	$0.13	$59.73	$549
2036	$30.57	33,792,305	$1,033	36,408,711	$1,103	$554	$549	2,291	2,618,697	$0.01	$55.09	$484
2037	$26.79	33,709,835	$903	36,325,556	$963	$473	$490	1,885	2,617,606	$0.00	$50.47	$414
2038	$25.56	33,753,359	$863	36,375,902	$919	$450	$469	417	2,622,959	$0.00	$46.82	$394
2039	$20.80	33,754,477	$702	36,372,163	$746	$372	$374	4,736	2,622,423	$0.03	$44.32	$328
2040	$21.97	33,870,433	$744	36,444,386	$786	$383	$403	23,572	2,597,525	$0.00	$27.36	$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

Table C8. High Fuel Prices + CO_2 Regulated (Case 4) 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)
			C * D				G-H					E-I
2025	$51.47	33,050,200	$1,701	10,787,094	$566	$458	$107	22,274,855	11,749	$1,102.92	$2.50	$1,594
2026	$51.32	33,155,652	$1,702	9,870,150	$513	$428	$85	23,286,154	652	$1,185.36	$1.18	$1,617
2027	$52.02	34,025,754	$1,770	9,454,595	$499	$426	$72	24,571,159	-	$1,263.71	$0.52	$1,698
2028	$54.05	34,075,501	$1,842	15,110,979	$825	$499	$326	18,966,337	1,815	$949.27	$4.12	$1,515
2029	$55.77	33,920,099	$1,892	15,813,151	$896	$518	$378	18,128,119	21,171	$909.02	$5.82	$1,514
2030	$57.60	33,808,022	$1,948	16,031,415	$944	$557	$387	17,803,790	27,182	$910.16	$8.94	$1,560
2031	$60.34	33,768,873	$2,038	16,203,495	$998	$588	$410	17,598,054	32,676	$914.01	$10.27	$1,628
2032	$61.77	33,827,370	$2,090	16,100,074	$1,015	$601	$414	17,757,647	30,351	$916.92	$9.30	$1,675
2033	$62.64	33,717,105	$2,112	16,142,515	$1,028	$583	$445	17,581,002	6,413	$964.85	$4.64	$1,667
2034	$62.77	33,675,259	$2,114	25,022,849	$1,570	$655	$914	8,745,040	92,630	$424.24	$22.49	$1,199
2035	$64.26	33,133,831	$2,129	26,075,315	$1,673	$676	$997	7,302,757	244,241	$355.82	$39.46	$1,132
2036	$63.36	33,792,305	$2,141	29,348,510	$1,831	$677	$1,154	5,096,553	652,758	$241.45	$59.07	$987
2037	$54.86	33,709,835	$1,849	32,355,342	$1,719	$646	$1,073	2,623,302	1,268,809	$115.68	$75.85	$776
2038	$53.21	33,753,359	$1,796	32,799,120	$1,685	$635	$1,050	2,387,451	1,433,212	$104.00	$80.79	$746
2039	$33.14	33,754,477	$1,119	35,572,010	$1,130	$580	$551	429,299	2,246,832	$18.26	$67.27	$568
2040	$32.50	33,870,433	$1,101	35,795,386	$1,111	$609	$503	383,269	2,308,222	$18.56	$66.13	$598

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