Entergy Louisiana

2023 Integrated Resource Plan

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Chapter 1 Executive Summary

The past three years have brought unprecedented change for the world. A global pandemic, inflation, and geopolitical conflicts have changed the trajectory of the world economy and the ripple down effect to industry is reshaping how Entergy Louisiana, LLC ("ELL" or the "Company") views its current state. These impacts, combined with the increasing threats posed by climate change, mean that the time is now to reimagine Louisiana's energy future.

Key imperatives that will drive planning for ELL include, but are not limited to:

- meeting customer demand for clean energy solutions,
- ensuring reliability and resiliency of the electric power grid while balancing affordability for all customers, and
- safeguarding the obligations of electric service providers to supply adequate generating capacity to meet electric demands.

ELL customers are demanding clean energy

The convergence of geopolitics and global energy security with a lower investment risk relative to the rest of the world puts the United States in a unique position to capitalize on opportunities to grow the economy and lead the world in the clean energy transition. In Louisiana and across the Gulf South, world-class infrastructure, favorable commodity spreads, workforce availability, and access to deep water ports put Louisiana and the region at the forefront for the U.S. to compete globally for new and expansion of its industrial customer base. A catalyst to this growth will be the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, both passed by the U.S. Congress and signed into law within the last year. These laws will provide billions of dollars in federal funding to enable historic investment in clean energy production, grid resiliency, and decarbonization across all industries.

In response to the opportunities and challenges before us, ELL is imagining and creating a bold future using sustainable business practices that integrate environmental, social, and economic objectives into all it does. ELL's strategies, plans, and actions are aimed at managing risks and realizing opportunities across its full value chain, from its customers to its company operations to its suppliers.

ELL's customers are demanding carbon-free energy to meet the goals of their investors and their own customers. New industries are attracted to ELL's low cost of energy and are leading the demand for clean generation. The push for net-zero Scope 2 emissions from existing and new customers, not only supports ELL's energy transition, but rather demands it.

With sustainability, reliability, and resiliency as guiding principles of its business strategy, ELL is generating positive outcomes for all its stakeholders. ELL is focused on several key customer-focused initiatives, including the following:

1. Focusing on its relentless safety objective: "Everyone safe—all day, every day."

2. Addressing its customers' goals, which align with its own, to reduce greenhouse gas emissions.
3. Fueling Louisiana's economy by capitalizing on unique growth opportunities for which ELL is geographically and operationally well positioned.
4. Strengthening its infrastructure by accelerating resilience investment and leveraging partnerships to increase the resilience of its communities.
5. Recruiting and retaining a workforce that reflects the communities ELL serves and has the skills needed to meet its objectives.

Reliability and resiliency of the power grid is essential

Vertically integrated and well-regulated utilities are essential for enabling the energy transition in an equitable manner. As the world shifts to a cleaner, greener economy, the electric grid will need to accommodate increased electrification and the increasing share of renewable generating resources. The industry has a long history of providing reliable and affordable energy and has evolved through a century of innovation. As the industry evolves yet again, vertically integrated utilities have the expertise in engineering, infrastructure, customer engagement, community connections, and energy markets to enable the transition to a cleaner energy industry.

In order to lead the transition, utilities will need to meet the growing demand for net zero generating resources, balance the intermittency of renewables, and invest in emerging technologies – all without sacrificing affordability and reliability.

Under the guidance and authority of the Louisiana Public Service Commission ("LPSC" or "Commission") and the rules that it has put in place, Louisiana has maintained amongst the lowest retail rates in the country. Attracted by Louisiana's natural resources and infrastructure, including low electricity prices and reliable power, billions of dollars of infrastructure have been invested in the State, creating thousands of jobs for Louisiana residents. Louisiana has a strong foundation, and ELL seeks to fortify and grow that foundation.

Vital to Louisiana's growing economy is the assurance that utility resources and infrastructure are in place to reliably meet the needs of existing and new commercial and industrial customers, within a regulatory paradigm that has been historically proven to maintain affordable rates and equitable outcomes for all customers. And, as discussed previously, the ability to meet customer requirements for access to clean energy resources are becoming the new table stakes for utilities.

Recent weather events have highlighted the need for continued and accelerated investments in resilience to make sure grid infrastructure can quickly recover from disruptive events and allow homes and businesses to return to normal operations. ELL supports continued growth in the State through its continued investment in Louisiana which allows ELL to power the lives of its customers with clean, affordable, and reliable electricity. This growth, in turn, leads to innumerable improvements in Louisiana communities including increased investment in its schools, streets, parks, and other resources that enhance the daily lives of Louisianans. The reliability and resilience of the electric system depends on long-term resource planning and Commission oversight of ELL and all regulated utilities in the state. This Integrated Resource Plan ("IRP") is a product of a dynamic, ongoing process and this Report provides a touchstone for that process.

The rapid rate of change in the economy and the competitive advantages inherent to Louisiana, which will contribute to rapid growth in the demand for electricity, requires ELL to evaluate needs at a much faster rate than ever before. The IRP process has always been a view of the future at a point in time, but now, more than ever, ELL must and will pivot as necessary to ensure that as a utility, it will not only enable load growth in the state, but it will be a lynchpin in the competitive advantage Louisiana offers to businesses from around the world.

Since joining the Midcontinent Independent System Operator, Inc ("MISO") in December 2013, ELL, with approval from the Commission, has added over 2.9 gigawatts ("GW") of new, dispatchable generation in the state. This investment of more than $2.5 billion in new, dispatchable generation was needed to reliably serve Louisiana customers and support approximately 120 announced economic development projects in Louisiana, totaling over $108 billion in capital investments and creating approximately 14,190 new direct jobs over the last decade. More recently, ELL has added 55 megawatts ("MW") of solar generation, obtained LPSC approval to add nearly half a GW of new solar generation, sought certification of an additional 224 MWs of solar generation, and has outstanding and forthcoming Requests for Proposals ("RFPs") at various stages of development seeking to add an additional 4.5 GWs of renewable generation. The Company has also gained approval of a new green tariff, the Geaux Green Option or Rider GGO, which will, among other things, allow for adding new renewable generation at a significantly reduced cost for typical customers while also ensuring all customers benefit from such resources.

In light of customer demand for clean energy resources and a desire and directive from the LSPC to facilitate the renewable transition more expeditiously,[1] ELL and the LPSC must improve the current process for vetting and approving the addition of new renewable resources. The Market Based Mechanisms Order and other relevant processes at the LPSC require a significant amount of time, in some case upwards of four to five years from beginning (i.e., issuance of a request for proposal) to end (i.e., operation of a resource). The renewable market is a rapidly evolving market and customer demand is growing at an exponential pace. To meet this demand, ELL and the LPSC must take into consideration opportunities to add renewable resources at a pace that matches it. As ELL and the LPSC continue to navigate this aspect of the clean energy transition, ELL will consider opportunities for unsolicited offers that provide benefits to customers (such as the Elizabeth Solar PPA approved by the LPSC in September 2022). Further, parties should consider alterative RFP processes that allow utilities to add resources in a timely manner while also ensuring that appropriate considerations for resource adequacy and the public interest are taken into account. ELL recently proposed to implement such a process to facilitate the addition of 3 GW of solar resources in LPSC Docket No. U-36697.

Prudent utility planning ensures resource adequacy for customers at all times

Participation in MISO has brought value to Louisiana customers over the last nine years. ELL estimates that its customers have realized approximately $845 million in savings from ELL's participation in MISO (through 2022), primarily as a result of lower reserve margins and MISO's

[1] See, Order No. U-36190 (October 14, 2022), Docket No. U-36190, In re: Application for Certification and Approval of the 2021 Solar Portfolio, Rider Geaux Green Option, Cost Recovery and Related Relief.

economic dispatch of generation through its energy market. MISO, however, has no authority over, or responsibility to, provide or build generating capacity, and its planning resource auction ("PRA"), which is limited term in nature, is not structured to cover the long-term cost of adding new generation. The MISO annual PRA provides a mechanism for load serving entities to balance short term surpluses or deficits of zonal resource credits required to meet their planning reserve margin requirement ("PRMR"); it is not a source of long-term capacity, and as the Federal Energy Regulatory Commission ("FERC") has recognized, it was never intended to serve as the primary mechanism for LSEs to procure capacity. Rather, MISO relies on its load serving entities (like ELL), under the regulation of state commissions (like the LPSC), to build or acquire the right amount and type of physical generating capacity to ensure resource adequacy and reliability. Recent resource planning and procurements by electric cooperatives have, to varying degrees, evidenced an intent to rely upon unidentified generation sources, including the PRA for a significant portion of their respective PRMR, instead of identifiable physical capacity. Ironically, this is occurring at a time when MISO is raising concerns about resource adequacy, and neighboring regions (SPP and ERCOT) are taking steps to increase resource adequacy requirements. The actions taken by some of the electric cooperatives do not represent prudent long-term resource planning. In addition to creating reliability risk for all load in the state, the cooperatives' continued misuse of the PRA as a primary source of capacity may call into question whether the public interest continues to be served by remaining in MISO.

An additional threat to resource adequacy in the state, as well as to economic development and equitable outcomes for all customers, is the recent discussion of drastically altering the heretofore successful regulatory landscape for the state of Louisiana by potentially allowing for full or partial Retail Open Access ("ROA"). Although, after a lengthy and thorough regulatory proceeding, the LPSC previously concluded that ROA is not in the public interest for any customer class, certain entities that stand to benefit financially from ROA (*e.g.*, merchant wholesale generators and a few larger industrial customers) continue to advocate for some form of ROA, which is at times referred to as "customer centered options." The latest iteration of ROA that is being pursued by these entities is a type of limited/partial ROA for industrials, which is being sold (inaccurately) as a way to avoid the need for investment in new generation assets, support private investment, shift risk away from utility customers, and allow industrials to expedite the transition to renewables at their own risk. ELL supports and advocates for new customer solutions that, under oversight of the Commission, can provide benefits to all utility customers, like the recently approved Rider GGO and the recently proposed Zero-Emission Resource Option (Geaux ZERO or Rider GZ). Such options must be designed in consideration of, and well-suited to address, each utility's unique customer bases and capacity and energy needs. However, the implications of full or even partial ROA could have detrimental impacts to all customers in the state of Louisiana and would be counter-intuitive to the goals of the Commission's IRP General Order and the associated planning process.

These threats to resource adequacy are made more urgent by ELL's analysis that MISO Local Resource Zone ("LRZ") 9 may reach a capacity shortfall as soon as 2025, after accounting for new resource additions that have been filed for approval before the LSPC as well as future resource deactivations and retirements. MISO itself has expressed concerns about capacity shortfalls in the near future. Specifically, MISO observed that 55 GW of capacity could retire by

2040 while an additional 4 GW of committed capacity will be needed by 2026 to meet regional requirements.[2] This situation is further exacerbated because, as MISO observes: "the majority of resources currently being retired are thermal baseload resource [sic], which generally are associated with relatively higher resource adequacy accreditation levels than the variable and/or intermittent resources with which they are being replaced."[3] When or if this potential capacity shortfall materializes, the entire LRZ 9 is at risk of clearing at the cost-of-new-entry ("CONE") prices within future MISO PRAs, significantly increasing costs and jeopardizing future reliability for all within the region. The trends observed by MISO have already materialized in other MISO LRZs, with seven LRZs clearing at CONE in the 2022-2023 MISO PRA. The recently released PRA results for the 2023-2024 MISO Planning Year[4] include substantially increased prices in LRZ 9, suggesting that the troubling trends identified in ELL's analysis and MISO's observations are continuing, and providing further evidence of the reduced availability of capacity within the zone. Indeed, the results show that the capacity surplus in MISO South decreased by nearly 40% from last year's auction to this year's and MISO notes that capacity in the South exceeds requirements by only 5.1% In that regard, the recent experience of MISO North, which has a 4.7% surplus in this year's auction but, just last year, had every LRZ clear at CONE, shows that current the 5.1% capacity surplus in MISO South is sufficiently narrow that it could easily become a deficit in a single year. It is also worth noting that the Fall and Winter pricing for LRZ 9 is significantly higher than pricing for any other zone. This is because higher priced resources were necessary to meet the Local Clearing Requirement ("LCR") of LRZ 9.

Just as the past three years have been unexpected and full of change, the next several years promise to be more of the same. Opportunities for industrial expansion and development in Louisiana will drive a substantial increase in load for ELL while also creating economic development for Louisiana that has not been achieved in decades. A crucial requirement to achieve this expansion is the availability of carbon free electricity to enable companies to reduce their scope 1 and scope 2 emissions, as well as firm capacity availability and stability. As ELL lays out its Integrated Resource Plan, doing its part to ensure the economic success and environmental sustainability for Louisiana will be a key driver for its actions.

ELL Customers

ELL provides electric service to more than 1.1 million customers and has residential, commercial, industrial, and governmental customers in 58 of Louisiana's 64 parishes. It also provides natural gas service to more than 96,000 customers in Baton Rouge, Louisiana. By combining an understanding of what customers want with sound and comprehensive planning, ELL can deliver the type of service its customers expect while continuing to address the planning objectives of affordability, reliability, and environmental stewardship.

Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in energy efficiency ("EE")

[2] *See,* Motion for Leave to Answer and Answer of the Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-496-00.

[3] Id.

[4] See https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628922.pdf

standards. Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived.

ELL is actively engaging its customers to obtain a better sense of those expectations and the ways in which ELL can bring offerings to the marketplace to meet those expectations. As a result of this engagement, one of ELL's goals is to develop products that will reduce its customers' scope 2 emissions. ELL's customers' sustainability objectives go far beyond reductions in scope 2 emissions since many of them have on-site equipment and processes that utilize fossil fuels and emit carbon dioxide. To achieve their decarbonization goals, these customers will need to modify their operations and processes to eliminate scope 1 emissions. They are evaluating a wide set of solutions including electrification, carbon capture and storage, clean hydrogen, biofuels, and energy efficiency. Electrification appears to be a preferred method to replace and decarbonize aging equipment such as boilers, turbines, and compressors. Carbon capture and storage and clean hydrogen will also need to be powered by clean generation. Customers recognize ELL as a valued partner to help them achieve their decarbonization objectives. The solutions ELL designs today will deliver meaningful outcomes for all of ELL's stakeholders. Serving this electrification opportunity through the vertically integrated model has the added benefit of providing incremental contributions to utility fixed costs that will lower the share paid by other utility customers.

Historically, affordability and reliability have been foundational to attracting and retaining customer load. For decades, the Commission's leadership and ELL's planning efforts have made Louisiana one of the most attractive locations in the world for energy-intensive industrial and manufacturing operations, owing primarily to the low rates ELL's customers pay as well as the natural geographical advantages Louisiana offers. Increasingly, these same customers require the availability of zero-carbon emitting resources at scale as a top requirement for locating their business. While ELL's planning efforts have resulted in one of the cleanest generating fleets in the nation, to continue to remain an attractive electrical service provider to these kinds of customers and to maintain Louisiana as a preferred location for business and industry, ELL will need to facilitate these customers achieving their goals to decarbonize their operations. ELL's customers goals are being driven by their investors and their own customer bases, so ELL and the LPSC must recognize the importance of moving towards emission free generation. Providing customers with options for meeting their electricity needs with zero-carbon-emitting resources will be essential to keeping these businesses in Louisiana, as well as to pursuing opportunities to attract new businesses to the region.

Fortunately, ELL, its customers, and the Commission are currently poised to take advantage of these opportunities due to ELL's prudent long-term planning efforts, ELL's customers' investment in the existing generation portfolio, and the Commission's oversight of these efforts and investments. ELL is well positioned to continue adding zero-carbon resources to its resource mix in a way that will maintain reliability and provide net benefits to all customers, without shifting costs or burdens to customers of other utilities. Coupling those resources with customers solutions, e.g., ELL's recently approved Rider GGO in LPSC Docket No. U-36190 and ELL's recently proposed Geaux ZERO rider in LPSC Docket No. U-36697, will further enhance ELL's ability to help these current customers, and potential new customers, meet their sustainability goals by allowing them to directly match portions of their electricity needs with energy from renewable resources. Additionally, by coupling new renewable resources with such customer solutions, ELL has an opportunity to mitigate the costs of these resource additions and ensure all customers benefit.

Environmental Stewardship

Entergy Corporation ("Entergy") has been an industry leader in voluntary climate action for over two decades. Building on its longtime legacy of environmental stewardship and in response to customer demand, Entergy has enhanced its climate action strategy with near-term interim goals to achieve 50% carbon-free energy generating capacity by 2030 and to reduce its emission rate by 50 percent of 2000 levels by 2030, and a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. ELL intends to contribute to meeting these goals by working with the Commission and other stakeholders to balance reliability, affordability, and environmental stewardship while transforming its portfolio and building a diverse generation fleet that maintains the grid's resilience and reliability and delivers on the shared environmental commitments among ELL and its customers. This work will be critical for helping ELL customers achieve their sustainability goals, which goals also align with those of Entergy and the State of Louisiana's goal, as laid out in the Louisiana Climate Action Plan, to achieve net-zero by 2050 for the state. As discussed above, these efforts are also needed to bolster continued economic development in the State.

In ELL's 2019 IRP, its Action Plan included ELL's intention to issue an RFP for renewable resources no later than early 2020 and anticipated that it would follow that RFP with a recurring series of RFPs for renewable resources. Since that time, ELL has issued RFPs in 2020, 2021 and again in 2022. Its 2020 RFP sought up to 300 MW of solar resources, with an option to provide battery storage, for resources located within ELL's Southeast Louisiana Planning Area ("SELPA"). ELL made selections from that RFP, negotiated with the successful bidders, and filed for certification of four new solar resources in November of 2021 that will collectively provide 475 MW of new solar resources in Louisiana. ELL received certification for these resources in September of 2022 and anticipates that these resources should be online in 2024 and 2025.

ELL's 2021 RFP sought up to 600 MW of solar resources, with an option to provide battery storage, for resources located within SELPA. The filing that seeks certification for 224 MW of resources, including the resource that resulted from this RFP, is currently pending in Docket No. U-36685. ELL's 2022 RFP seeks up to 1,500 MW of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of Louisiana for solar resources, and all of MISO South and/or SPP for wind resources. Out of this competitive solicitation, ELL has made selections, is currently negotiating with counterparties, and intends to seek certification of all contracted for resources in late 2023 or early 2024. Finally, ELL has also sought the Commission's approval to acquire up to 3,000 MW of additional solar resources in Docket U-36697 coupled with a proposed alternative market-based mechanism process to allow for more timely procurement of such resources.

Separate from ELL's work to decarbonize its generation, another critical opportunity for decarbonization is clean electrification. Clean electrification is a longer-term option to help customers reduce their scope 1 carbon emissions. This is a unique and significant opportunity for ELL. ELL's commercial and industrial customers have decarbonization goals, and electrification is an important, cost-effective means for them to achieve their objectives.

To summarize, ELL has made several recent strides to meet customer demand and resource constraints.

- The LPSC has approved ELL's 475 MW solar portfolio,
- ELL has sought certification of an additional 224 MW solar portfolio,
- ELL has solicited or is in the process of soliciting upwards of 4.5 GW of additional solar or wind,
- ELL recently announced Memoranda of Understanding with Diamond Offshore Wind and RWE, AG regarding the evaluation and potential early development of wind power generation in the Gulf of Mexico,
- Entergy Corporation and Mitsubishi Power signed a joint development agreement to collaborate on developing hydrogen-capable gas turbine combined cycle facilities, developing green hydrogen production, storage and transportation facilities, creating nuclear-supplied electrolysis facilities with energy storage, and developing utility scale battery storage programs,
- Entergy Corporation entered into a Memorandum of Agreement with Holtec for evaluation of potential installation of one or more smaller nuclear reactors at one of its existing nuclear locations, and
- ELL's proposal that was submitted to the United States Department of Energy (DOE) for the purpose of obtaining a financial assistance to support integrating a full-scale CCS facility at the Lake Charles Power Station was recently selected for negotiation of a financial assistance award.

About This Report

This document describes ELL's long-term IRP for the study period 2023-2042 and is intended to provide stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar fundamental uncertainties remain when compared to ELL's last IRP, which was filed with the LPSC on May 23, 2019, in Docket No. I-34694. These uncertainties include advances in renewable technologies and their associated costs, growing customer preferences for renewable energy, and prospective changes in environmental regulations. Based on subsequent analysis, although ELL's total generating capacity is forecasted to be nearly equal to its peak customer demand plus reserve margin target in 2023 and 2024, it is forecasted to have a capacity deficit in 2025 that is briefly resolved in 2026 due to ELL's ongoing Renewable RFPs. That deficit returns in 2027 and expands over time as forecasted customer demand increases and existing resources reach the end of their assumed useful lives.

As with the Company's last IRP, the 2023 IRP utilizes a futures-based approach by which three possible future worlds were constructed to reasonably bookend a broad range of future uncertainties. An economically optimized portfolio of both supply-side and demand-side resources was developed for each of the three futures. Summaries of the modeled portfolios are discussed further in Chapters 5 and 6.

The IRP analysis has been updated to incorporate key renewable energy provisions included in the Inflation Reduction Act (IRA) of 2022, which was signed into law in August 2022. The IRA includes tax credits for clean energy technology, with the goal of reducing carbon emissions, which credits have been factored into ELL's analysis. In addition to incorporating key IRA provisions, the IRP analysis incorporates an update to the solar technology transmission interconnection cost, following through on the interactive IRP stakeholder engagement process to review solar interconnection costs. The IRP analysis is described in greater detail below.

The results of the IRP analysis reasonably support that ELL's future supply-side resource additions primarily will consist of renewable energy resources that are enabled and complemented by ELL's existing dispatchable generation resources. ELL's Reference Resource Plan maintains the planning assumptions for existing units and continues adding renewable resources starting with solar resources followed by complementary wind resources until battery storage additions are needed to move intermittent renewable energy to hours of high customer demand net of renewable energy production. Additionally, a limited number of hydrogen capable gas CCGT units are added when existing large gas units are assumed to deactivate. The exact amount and timing of each type of resource addition will be based on market solicitations and may vary from the information included in ELL's Reference Resource Plan.

Since the 2019 IRP, favorable long-term market conditions (e.g., the declining cost of utility-scale solar and recent federal legislation) are prevailing at a time of significant customer demand for clean energy solutions and a need to transform the Company's resource portfolio. This confluence of favorable market conditions and changing customer preferences supports the addition of significant amounts of new renewable resources in ELL's Reference Resource Plan and other assessed Portfolios that were not selected in prior IRPs, and which are now expected to result in significant variable supply cost savings for customers over the twenty-year planning horizon. These savings will be realized by all ELL customers through the fuel adjustment and are projected to almost entirely offset the base rate increases associated with new resource additions. The rate impact estimates, presented in Appendix I, notably do not account for the rate effects of future customer offerings (e.g., Riders GGO and GZ), additional Adjusted Gross Margin (AGM) associated with new industrial sales from incremental electrification and load expansions, and/or of deactivating or retiring resources, which may further lower net costs for all customers during the planning period.

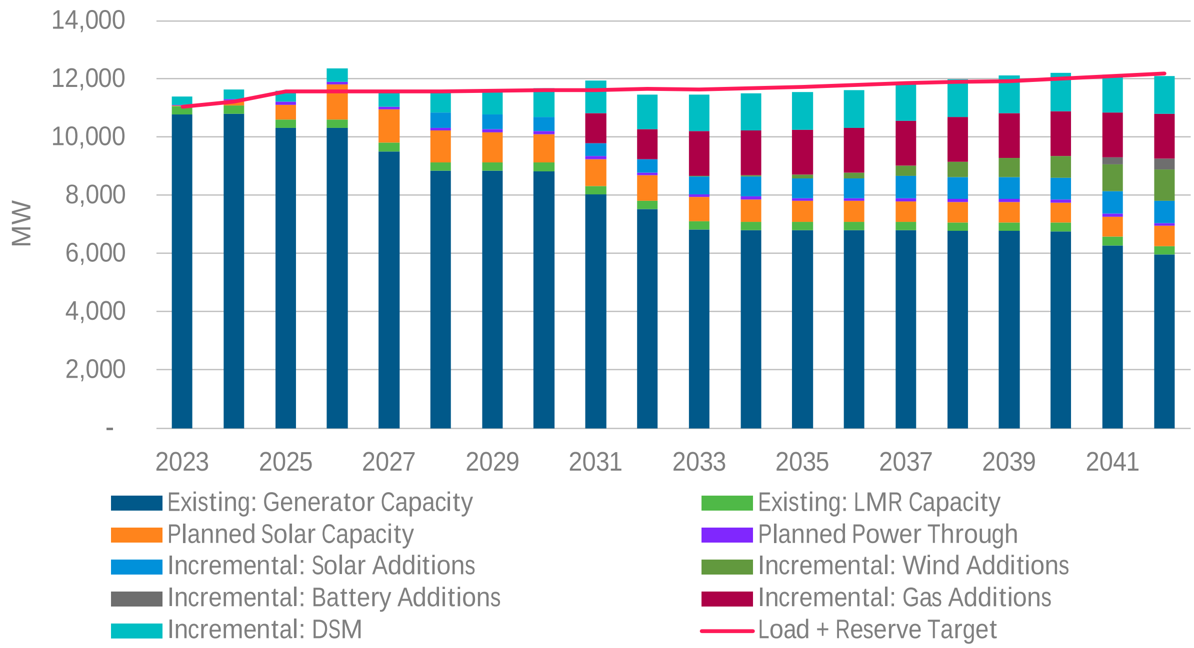


Figure 1: 2023 IRP Reference Resource Plan

The IRP's future resource portfolios are developed consistent with the Commission's Integrated Resource Planning General Order but do not represent planning decisions by ELL. Rather, the Company's specific long-term resource planning actions (e.g., capacity additions) are subject to review and approval by the Commission in future certification proceedings. In the same respect, the IRP's assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost or ownership structure for implementing those options. They are planning assumptions, with the actual costs and structures to be determined at the time of execution, likely through a market solicitation. In addition, while the IRP seeks to identify ELL's capacity needs and appropriate resources to fill those needs, this approach should not be read to foreclose the identification of a future resource which may provide significant energy value to ELL's customers or otherwise that provides value to ELL's customers and was not identified within this IRP.

ELL recognizes that creating an affordable, reliable, and sustainable future for its customers and their communities requires continued transformation of the Company's resource portfolio, and this IRP provides insights into ELL's planning process, including an illustration to show how the planning principles are applied to long-term resource planning. Affordability, as measured through the total relevant supply cost metric, is but one factor used in determining the reference IRP portfolio. In conducting the IRP and selecting a Reference Resource Plan, ELL considers cost and market risks, in addition to viability, sustainability, and executability to determine which portfolio can be most helpful in guiding future resource planning decisions that will deliver reliable service at a reasonable cost and in a sustainable manner. A full description of these qualitative risk factors is contained in Chapter 5 and ELL's selection of a Reference Resource Plan is discussed in detail in Chapter 6. Looking ahead, ELL will continue to work with regulators and its key stakeholders to transform its portfolio, building a diverse generation fleet that maintains the grid's resilience and reliability and delivers on the shared environmental commitments among ELL and its customers.

While no specific approvals are sought for this IRP pursuant to the Commission's Integrated Resource Planning General Order, the Reference Resource Plan and Action Plan outlined in Chapter 6 of the IRP reflect ELL's present expectations regarding the planning actions that can be expected over the next several years based on relevant and available information. It is important to note that these action items, as well as the Portfolios modelled herein, are consistent with Entergy's announced sustainability and emissions reductions goals and ELL's objective to provide reliable, affordable electric service to customers, which goals are driven by customers' own objectives, and this Report should be informative to stakeholders interested in the path that will lead to the accomplishment of those goals. While this Report does not represent a resource planning decision, the Company is encouraged by the fact that each of the least cost Portfolios identified through the IRP analyses are consistent with these objectives and, as such, the objectives do not appear to create additional incremental costs for customers beyond what would otherwise be incurred to reliably serve customers at a reasonable cost.

The 2023 IRP Action Plan consists of eight action items, which are summarized below and discussed in more detail in Chapter 6:

1. Implement ELL's Solar Portfolio & Geaux Green Tariff (2020 RFP)	Pursuant to the recently approved certification, ELL intends to add three new contracted solar resources (Vacherie, Sunlight Road & Elizabeth) and one new owned resource (St Jacques) to its generation portfolio. Additionally, ELL will implement Rider GGO, a new green tariff which will allow participants to subscribe to and receive value from these four solar resources to address their decarbonization objectives. The Company intends to expand Rider GGO and/or develop other renewable options (e.g., the recently proposed Rider GZ) to provide benefits to all customers (including non-participants) and address future capacity needs, where feasible.
2. Complete ELL's Two Outstanding RFPs (2021 & 2022 RFPs)	ELL's 2021 RFP sought up to 600 MWs of solar resources, with an option to provide battery storage, for resources located within SELPA. ELL recently sought certification of the resource proposal that ultimately resulted in an executed commercial agreement, along with another 49 MW solar resource, in Docket U-36685. ELL's 2022 RFP seeks up to 1,500 MWs of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of

	Louisiana for solar resources, and all of MISO South and/or SPP for wind resources. ELL is in the process of negotiating commercial agreements for resources selected from this RFP and anticipates seeking certification of contracted for resources in late 2023 or early 2024.
3. Continue the Issuance of Sizeable and Frequent Renewables RFPs	ELL intends to continue to issue sizeable and frequent renewable RFPs in an attempt to respond to customer preferences, diversity of ELL's generation portfolio, capitalize on the improving economics of solar and potentially other technologies relative to conventional generation resources, economic development opportunities, and ultimately to work toward its 2030 and 2050 sustainability goals, respectively. In response to the Commission's recent Order,[5] ELL will also work with the Commission and other stakeholders to find ways to expedite this process. Notably, in March 2023, ELL filed an application for the approval of an alternative market-based mechanism process to secure up to 3,000 MWs of solar resources, certification of those resources, potential expansion of Rider GGO and approval of Rider GZ (Docket No. U-36697). In addition, as the market continues to evolve and developers initiate projects, in accordance with LPSC guidelines, ELL will evaluate and respond to any unsolicited offer it may receive for viable renewable resource additions.
4. Cross-State Air Pollution Rule ("CSAPR")	It is anticipated that the Environmental Protection Agency's (EPA) published rule will be the subject of numerous legal challenges in various jurisdictions across the country and it is uncertain when those challenges will be resolved or what effect they may have on ELL's compliance obligations. ELL will continue to monitor the status of such challenges, as well as related legal challenges to EPA's disapproval of the Louisiana State Interstate Transport SIP for the 2015 ozone NAAQS. In May 2023, prior to the rule being published in the Federal Register, the U.S. Fifth Circuit Court of Appeals issued a stay of EPA's disapproval of the related State Implementation Plan (SIP) developed by the State of Louisiana. This stay will prevent EPA's final CSAPR revisions from taking effect in Louisiana until such time as

[5] See Commission Order U-36190 (Dated October 14, 2022) at page 9.

	the stay is lifted. Details associated with the Court's decision and the potential impact thereof can be found in the Inputs and Assumptions section of Chapter 4. As these proceedings unfold, ELL will continue the ongoing process of assessing the impacts of the CSAPR, and the associated challenges thereto, and implementing a compliance strategy to meet any new or revised compliance obligations.
5. Explore Solving Some of ELL's Energy & Capacity Deficits with Distributed Generation and/or Customer Solutions	Distributed generation provides significant benefits to the grid and ELL customers through increased reliability, increased efficiency, grid balancing, peak load reduction and onsite local self-reliance for power generation needs. The LPSC's recent approval of ELL's Power Through program is a great example of a cost-effective opportunity to provide distributed generation coupled with resiliency for its customers. ELL will continue to evaluate opportunities to install distributed generation throughout its service territory as well as seek new opportunities for customer solutions that bring renewable generation, economic development and electrification to Louisiana.
6. Continue Participation in Commission Rulemakings (Resource Adequacy & Planning, Reliability)	ELL intends to monitor and participate in Commission rulemakings regarding resource planning, reliability and resource adequacy and evaluate actions that ELL should take to protect its customers from reliability and cost shifts resulting from cooperatives that plan to serve their load without appropriate long-term physical capacity, including exiting MISO.
7. Explore Additional Demand Side Management Opportunities	ELL stands ready to expand its current DSM offerings in accordance with applicable LPSC Rules[6] and Orders and where it is cost-effective to do so.

[6] ELL notes that in the on-going rulemaking related to administration of DSM programs (Docket No. R-31106), Staff issued new draft rules on March 7, 2022. Among other things, these draft rules (if implemented as drafted) would radically change the paradigm for administration of DSM programs by removing control of the programs from utilities and seeking to hire a statewide third-party administrator to oversee programs for all utilities. It is unclear whether this model will be implemented. As ELL noted in filed comments, the Company believes the ability to achieve cost-effective savings through DSM programs would be better served by allowing utilities with existing programs to retain control over them. The discussion of DSM, and the potential benefits thereof, throughout this report and in the DSM Potential Study assumes that ELL would still be allowed to administer DSM programs once the Commission's rules are finalized and implemented. On May 4, 2023, the LPSC issued an order extending the current rules until December 31, 2025.

8. Pursue Power Resiliency	In December 2022, ELL filed its Entergy Future Ready Resilience Plan highlighting its plan to accelerate the resilience of its electric system through a comprehensive set of cost-effective hardening projects (Docket No. U-36625).

Chapter 2 Long-Term Resource Planning

Summary

- In 2012, the LPSC issued a General Order requiring its jurisdictional utilities to file an IRP at least every four years; this is the third IRP filed by ELL since the LPSC issued its Integrated Resource Planning General Order.
- The IRP process incorporates ELL's resource planning objectives, which complement the LPSC's General Order.
- ELL has made significant progress on the action items identified in its 2019 IRP Action Plan.

Introduction

This document describes ELL's long-term IRP for the period 2023 – 2042. This is the third IRP filed by ELL since the LPSC issued its Integrated Resource Planning General Order in Docket No. R-30021. Similar to prior IRPs, ELL's 2023 IRP reflects the fact that uncertainty remains an issue that must be considered in long-term resource planning, with no outcome providing absolute certainty as to the appropriate path for the utility to take. In other words, the uncertainties that dominated ELL's 2019 IRP filed with the Commission on May 23, 2019 (e.g., advances in renewable resource technology) remain but have been expanded to include other uncertainties, such as the impact and role of more significant amounts of renewable generation in the market and the growing demand from customers, evolving customer preferences, geopolitical conflicts that shift supply chain and locational optimization for industrial processing, climate change, and policy uncertainty at the local, state and federal level. This is not an exhaustive list, but rather one that will continue to grow over time and will require the attention and action from ELL.

As indicated in Chapter 1, this IRP does not provide a fixed path for future ELL resource planning. Rather, ELL's specific long-term resource planning actions (e.g., capacity additions) typically are subject to review and approval by the Commission in separate proceedings. The Action Plan contained within this IRP reflects ELL's current expectations regarding the planning actions the Company will take over the next several years and, consistent with the IRP rules, identifies a Reference Resource Plan based on information available today. As the industry pivots, ELL will address the changing economy and maintain flexibility in meeting the demands of its customers without sacrificing affordability, reliability, or environmental stewardship.

Resource Planning Objectives

ELL's resource planning efforts are driven by the fundamental goal to deliver a sustainable resource portfolio that is centered on customer outcomes. Building a sustainable portfolio requires that ELL carefully balance three key objectives: reliability, affordability, and environmental stewardship. This balance looks at both the near-term and long-term benefits and risks associated with each key objective.

Figure 2: Key Planning Objectives

ELL's development of a sustainable portfolio places an emphasis on customer preferences. ELL recognizes that customer expectations for electric service will continue to change alongside advancements in technology and evolving market and policy considerations both in and out of the traditional utility framework. Accordingly, ELL aims to meet customers' needs for reliable, reasonably priced electric services and energy solutions both for those expected today and in the future.

Through the IRP process, ELL conducts an extensive study of customers' needs over the next 20 years based on currently available data. It does so by analyzing the costs and benefits of supply-side and demand-side alternatives to develop resource portfolio options that help meet ELL's planning objectives. The results of the IRP are not intended to represent static plans or pre-determined schedules for resource additions.

Regulatory Context for ELL's IRP

ELL's previous two IRP cycles have concluded with Staff recognizing that ELL has met the requirements of the Commission's IRP General Order, with no disputed issues requiring further resolution, and recommended that the LPSC acknowledge ELL's Final IRP report. In both instances, the Commission accepted Staff's recommendation. ELL endeavors to continue to work closely with Staff and Stakeholders throughout this process, and in accordance with the rules specified in the Commission's General Order, to achieve the same outcome in this IRP cycle.

Chapter 3 Integrated Resource Planning Process

Summary

- ELL's IRP strategy ensures that the Company is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship for its customers while providing flexibility to respond and adapt to a constantly shifting utility landscape.
- This strategy requires balancing many different variables, including evolution in technology and customer preferences, resource and transmission attributes, MISO resource adequacy requirements, and sustainability goals.

The IRP plays an important role in the iterative process of planning ELL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources to ELL planners, as well as stakeholders. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that typically are presented to the Commission for approval.

The considerations detailed in this report are focused on efficiently meeting all of ELL's customers' ever-changing supply needs. ELL's IRP strategy ensures it is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship for its customers in the future. This approach also provides the flexibility ELL requires to respond and adapt to a constantly shifting utility landscape. In response to customer demand and a business environment that is increasingly focused on sustainability and renewable energy goals, ELL received LPSC approval in early 2022 for two new renewable energy credit ("REC") based green pricing options in LPSC Docket No. U-35916. Those two new offerings, Riders GPO and LVGPO, have been open for customer enrollment since May 2022.[7] Also, in September of

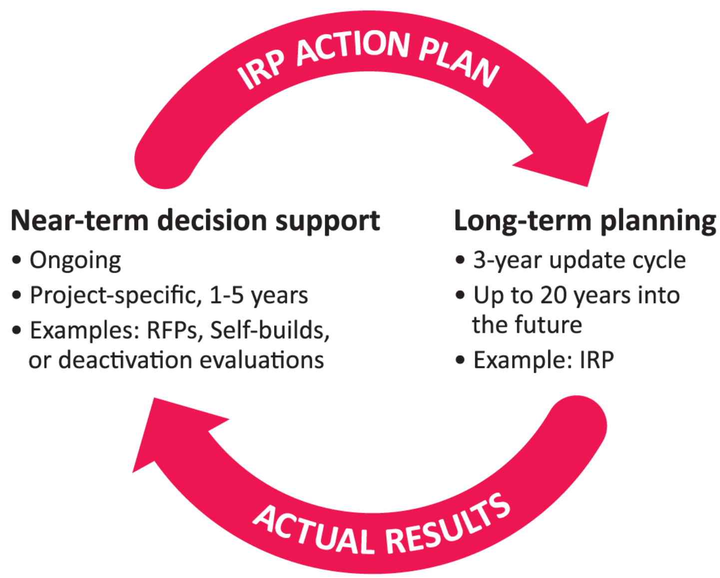


Figure 3: ELL IRP Strategy

[7] These offerings are being marketed to customers under the product names "Entergy Green Select" and "Entergy Green Select – Large Volume", and both products are Green-e® certified by the Center for Resource Solutions. *Available at* https://renew-louisiana.entergy.com/

2022, ELL received certification for a Geaux Green Option tariff in Docket No. U-36190 that offers a solution for customers to subscribe to the green tariff solution that includes RECs and value from renewable energy that is sourced from solar resources located within Louisiana. ELL is also proposing the potential expansion of the Geaux Green Option and implementation of another renewable tariff (Rider GZ) in pending LPSC dockets, as noted above. All of these voluntary renewable offerings seek to provide participating customers access to renewable energy and to support economic development in Louisiana.

The twenty-year study period for the 2023 IRP outlines the current energy landscape as well as the challenges and opportunities that lie ahead. As in ELL's previous IRPs, the 2023 IRP is guided by ELL's Resource Planning Objectives, which focus on affordability, reliability, and environmental stewardship. This IRP looks at both the near-term and long-term benefits and risks associated with each key objective.

Existing Resources

ELL provides electric service to more than 1.1 million customers and has residential, commercial, industrial, and governmental customers in 58 of Louisiana's 64 parishes. It also provides natural gas service to more than 96,000 customers in Baton Rouge, Louisiana. The Company currently controls, through ownership, Power Purchase Agreements ("PPA"), or Demand Response ("DR"), a diverse array of resources totaling approximately 11,842 MW of installed capacity and zonal resource credits ("ZRCs") to serve these native load customers as of 2022. The table below shows ELL's ownership share of its resources by resource type.

Of this 11,842 MW, about one-fourth of ELL's total capacity is derived from legacy gas units, which range in age from 47 to 56 years of service and are assumed to deactivate over the course of the IRP planning horizon. As is discussed in further detail in the Environmental section of this IRP, the EPA's revision to its CSAPR may potentially accelerate some of the deactivation assumptions.

Approximately half of ELL's total capacity is derived from CT/CCGT units, which range in age from 2 to 22 years of service. Only two of ELL's CT/CCGTs are assumed to deactivate over the course of the IRP planning horizon. 2,200 MW of this fleet have been placed into service within the last 3 years.

In addition to these legacy gas assets, ELL also maintains less than 400 MW of coal fired generation within the supply portfolio, from ownership shares in the Nelson 6 and Big Cajun 2 Unit 3 facilities, in addition to affiliate Power Purchase Agreements associated with Independence and White Bluff. To date, these resources have provided fuel diversity and solid fuel assurance to ELL's customers. However, Entergy has announced plans to cease burning coal at these facilities by 2030.

The majority of the resources included in the table below are owned by ELL, but ELL also receives energy and capacity through PPAs for certain resources, including some from other Entergy affiliates. ELL purchases 12.6% of the output of Grand Gulf through a PPA with System Energy Resources, Inc. ("SERI"), an Entergy affiliate which owns Grand Gulf. ELL also purchases a portion of Entergy Arkansas, LLC's ("EAL's") excess baseload generation. ELL purchases 2.72% of the output of Arkansas Nuclear One ("ANO") 1, 2.71% of ANO 2, an additional 2.2% of Grand Gulf, 2.72% of EAL's owned share of Independence 1, 2.82% of EAL's owned share of White Bluff 1, and 2.6% of EAL's owned share of White Bluff 2. These PPAs are in effect for the life of the resource and are filed with and approved by FERC.

In addition to purchasing the output of certain units from other Entergy affiliates, ELL also sells the capacity and associated energy of some of its resource portfolio to other Entergy affiliates. ELL sells 20% of Ninemile 6 to Entergy New Orleans, LLC ("ENOL"), 31.88% of Perryville 1 and 2 to Entergy Texas, Inc. ("ETI"), 29.75% of River Bend 1 to ETI, and 10% of River Bend 1 to ENOL. ELL also sells to ENOL 1.84% of the generation owned by or under contract to Legacy ELL at the time of the transfer of the Algiers load to ENOL (the "Algiers PPA"). The Algiers PPA includes the output of Acadia 2, ANO 1 and 2, Grand Gulf, Independence 1, Little Gypsy 2 and 3, Montauk, Ninemile 4, 5, and 6, Oxy-Taft, Perryville 1 and 2, River Bend 1, Sterlington 7, Vidalia, Waterford 1, 2, 3, and 4, and White Bluff 1 and 2. These PPAs are also in effect for the life of the resources and are filed with and approved by FERC.

Additionally, ELL receives capacity and energy through third-party power purchase agreements. The power purchase agreements included within the assumptions for this IRP are included below.

Figure 4: Capital Region Solar

A new addition to ELL's portfolio since the 2019 IRP and a result of ELL's 2016 Request for Proposals[8], ELL executed a long-term PPA for a 50 MW solar photovoltaic ("PV") resource located near Port Allen, Louisiana named Capital Region Solar.[9] The Commission certified this resource on March 18, 2019, approving the PPA. The resource achieved commercial operation in September 2020 with ELL's PPA commencing on October 9, 2020.

As was stated in ELL's 2019 IRP, ELL has worked towards executing its action plan to support ongoing planning objectives and modernizing its fleet to support existing customers and load growth in the area served by ELL, specifically industrial growth in southern Louisiana. ELL has responded to this by adding 2.2 GW of efficient, reliable gas-fired generation within historically

[8] Entergy, Notice of the final results of the Entergy Louisiana, LLC;s 2016 Request for Proposals for Long-Term Renewable Generation Resources, Entergy Corporation (February 28, 2017), available at https://spofossil.entergy.com/ENTRFP/SEND/2016ELLRenewableRFP/Index.htm

[9] See, Order No. U-34836 (March 18, 2019), Docket No. U-34836, In re: Application for Authorization to Participate in a Contract for the Purchase of Energy and Related Benefits from the LA3 West Baton Rouge LLC Solar Facility

constrained areas[10] of ELL's footprint shown in Figure 5 below. The industrial sector is continuing to experience growth and is moving forward with a number of projects, including new projects and expansions of existing facilities.

Figure 5: Outline of ELL Planning Areas

In addition to these generating resources, ELL's portfolio also includes DSM resources that provide capacity value through reductions in customer load. For the 2022/2023 Planning Year, Load Modifying Resources ("LMRs") associated with legacy interruptible customer programs contributed approximately 280 MW of combined capacity including values associated with reduced line losses and reserves. In 2021, ELL also received LPSC approval for new interruptible service options.[11] As customers enroll in these new tariffs, the Company's portfolio of LMRs may increase providing further demand response value to ELL's customers.

In addition to the DR and interruptible options, ELL also manages a portfolio of EE programs that produce both energy savings for customers and a reduction in load served for the Company. These programs have reduced the Company's load behind the customer meter by an incremental 39.9 MW since 2018 and an aggregate 61.7 MW since programs were introduced in 2014. There are no prescribed energy savings targets under the current Commission EE rules, however, in 2022, the program achieved savings of 0.15% of 2012 retail sales. ELL exceeded its planned energy savings target with an overall achievement of 121% energy savings. EE programs offered

[10] The zones depicted on this map are used by Entergy Louisiana for resource planning purposes. WOTAB is the West of Atchafalaya Basin area. SELPA is the Southeastern Louisiana Planning area. Amite South is a sub-region of SELPA, and DSG is Downstream of Gypsy, which is a sub-region of Amite South.

[11] Entergy Louisiana, *Interruptible Service Program, available at* https://www.entergy-louisiana.com/interruptible/

in 2022 also exceeded cost-benefit thresholds established by the Commission in Docket No. R-31106. Gross program savings increased from 56,082 MWh for the 2021 Program Year to 64,846 MWh for the 2022 Program year. To further supplement its successful EE programs, in 2021 ELL also began offering several pilot programs including New Construction and Agricultural Solutions. Evaluated savings and overall goal achievement for the 2022 Program Year are shown in further detail in Table 1.

Table 1: EE Program Metrics

Evaluated Savings and Goal Achievement

Evaluation Metrics	2022
ELL Gross Savings (ex ante)	61,452 MWh
As adjusted by ADM Associates, Inc. for Realization Rate (ex post)	3,393 MWh
As adjusted for Net-To-Gross ("NTG") ratios	64,846 MWh
ELL MWh Target	53,669 MWh
% of Target Achievement Based on Evaluated Energy Savings	121%

ELL's current portfolio by unit is shown in Table 2 below. Additional details associated with these resources, as is required by the IRP General Order, can be found in Appendix D, and is further supplemented by a description of each unit that ELL owns and/or operates located in Appendix E.

Table 2: ELL Owned and Contracted Capacity

Power Generation Unit Name	ELL Ownership Share of GVTC [MW]	Resource Type
Acadia	526	Owned Resource/Affiliate PPA*
Arkansas Nuclear One 1*	22	Owned Resource/Affiliate PPA*
Arkansas Nuclear One 2*	26	Owned Resource/Affiliate PPA*
Big Cajun 2 Unit 3	135	Owned Resource/Affiliate PPA*
Calcasieu 1	142	Owned Resource/Affiliate PPA*
Calcasieu 2	159	Owned Resource/Affiliate PPA*
Grand Gulf*	203	Owned Resource/Affiliate PPA*
Independence 1*	7	Owned Resource/Affiliate PPA*
J. Wayne Leonard Power Station	912	Owned Resource/Affiliate PPA*
Lake Charles Power Station	913	Owned Resource/Affiliate PPA*
Little Gypsy 2	405	Owned Resource/Affiliate PPA*
Little Gypsy 3	504	Owned Resource/Affiliate PPA*
Ninemile 4	724	Owned Resource/Affiliate PPA*
Ninemile 5	728	Owned Resource/Affiliate PPA*
Ninemile 6	438	Owned Resource/Affiliate PPA*
Ouachita 3	241	Owned Resource/Affiliate PPA*
Perryville 1	355	Owned Resource/Affiliate PPA*
Perryville 2	101	Owned Resource/Affiliate PPA*
Riverbend 30	191	Owned Resource/Affiliate PPA*
Riverbend 70	389	Owned Resource/Affiliate PPA*
Roy Nelson 6	211	Owned Resource/Affiliate PPA*
Union 3	505	Owned Resource/Affiliate PPA*
Union 4	505	Owned Resource/Affiliate PPA*
Waterford 2	415	Owned Resource/Affiliate PPA*
Waterford 3	1155	Owned Resource/Affiliate PPA*
Waterford 4	32	Owned Resource/Affiliate PPA*
White Bluff 1*	13	Owned Resource/Affiliate PPA*
White Bluff 2*	12	Owned Resource/Affiliate PPA*
WPEC	370	Owned Resource/Affiliate PPA*
Agrilectric	9	Third Party PPA
Carville	485	Third Party PPA
Capital Region Solar	50	Third Party PPA

Oxy-Taft	471	Third Party PPA
Rain CII	28	Third Party PPA
Toledo Bend	48	Third Party PPA
Vidalia	133	Third Party PPA
Load Modifying Resources[12]	301	LMRs

Figure 6 below shows the percentage, by fuel type, of energy sources serving ELL's native load in 2022.

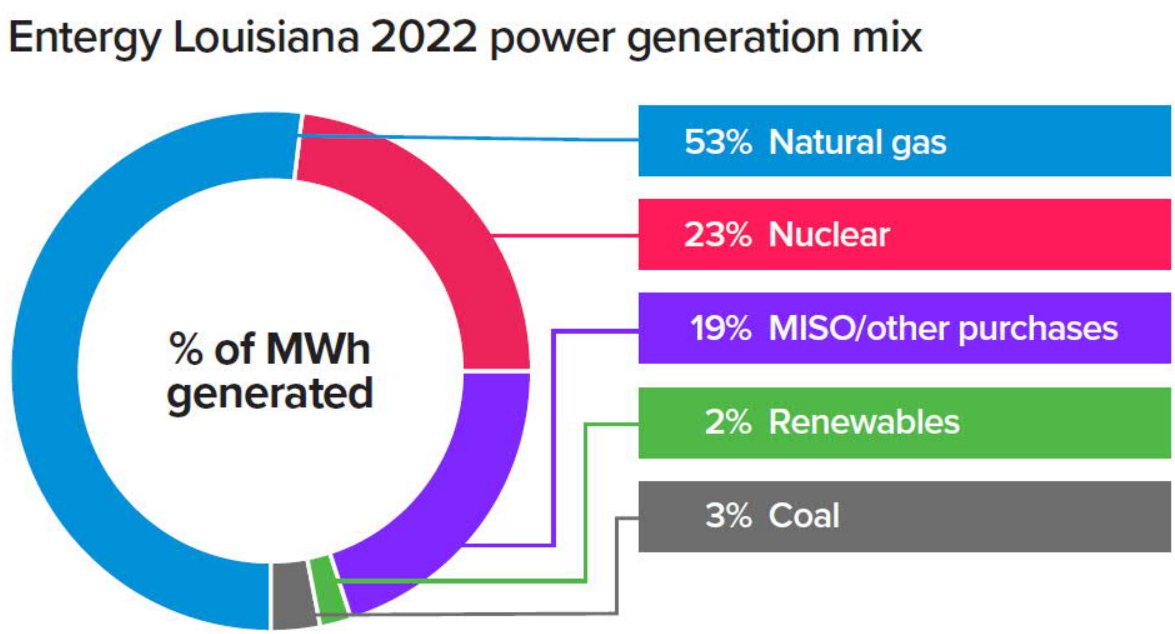


Figure 6: Entergy Louisiana 2022 Power Generation Mix

Future of Existing Resources

As indicated above, uncertainty is an ongoing issue that resource planners must consider in preparing long-term resource plans. In subsequent sections, ELL will review a number of factors that are assessed to guide and inform the portfolio design strategies and other issues facing ELL's planners.

Developing an IRP requires making assumptions about the future operating lives of existing generating units. Two key issues in this determination are the effective date of future environmental compliance requirements and whether the investments needed for ELL's older units to keep operating in compliance with those regulations are economical compared to alternative capacity resources. Another key issue in this determination is the assumed remaining

[12] ELL's existing interruptible load contracts included in the "Load Modifying Resources" assumed to remain in place throughout the entire study period

useful life of a particular technology type. In ELL's 2019 IRP, it was assumed that the useful life for CTs and CCGTs was 30 years. Since that time, ELL conducted a detailed analysis on the expected remaining useful life of those resources. The result of that analysis concludes that ELL's CTs and CCGTs are generally assumed to have a remaining useful life of longer than 30 years and most are assumed to operate beyond the end of the 2023 IRP study period (2042).

The IRP includes deactivation assumptions for existing generation to plan for and evaluate the best options for replacement capacity over the planning horizon. Based on the current design life assumptions incorporated into the IRP, a number of ELL's existing generating units and PPAs are anticipated to deactivate over the IRP planning horizon (2023-2042). During this planning period, the total reduction in ELL's capacity from the assumed unit deactivations and contract expirations grows to approximately 5,200 MW (~3,400 MW in the first 10 years). The deactivations and contract expirations anticipated over the first 10 years of the planning horizon are shown in the tables below.

Table 3: Near Term Deactivations

Near Term (10 Year) Deactivations[13]	Unit	ELL Ownership Share of GVTC [MW]	Deactivation Assumption
Big Cajun 2	3	135	2025
Waterford	2	415	2025
Little Gypsy	2,3	909	2027
Roy Nelson	6	211	2028
White Bluff	1,2	25	2028
Independence	1	7	2030
Ninemile	4	724	2031

Table 4: Near Term Contract Expirations

Near Term (10 Year) Contract Expirations	MW	Fuel	Expiration Date
Montauk	2	Biomass	2024
Toledo Bend	48	Hydro	2023
Oxy-Taft	471	Natural Gas	2028
Carville	485	Natural Gas	2032

[13] Following the ELL IRP Technical Conference, Sterlington 7A was deactivated. As a result, the resource has been removed from the table. It is important to note that ELL only owns a portion of Big Cajun 2 Unit 3, Roy Nelson Unit 6, White Bluff Units 1 and 2, and Independence Unit 1. The entire GVTC ratings for those respective units are currently 557 MW for Big Cajun 2 Unit 3, 524 MW for Roy Nelson Unit 6, 818 and 823 MW for White Bluff Units 1 and 2, respectively, and 822 MW for Independence Unit 1.

These deactivation assumptions do not constitute a definitive deactivation schedule but are used as planning tools and help to prompt cross-functional reviews and recommendations. It is not unusual for these assumptions to change over time given the dynamic use and operating characteristics of generating resources. Additionally, for ELL's nuclear fleet, the IRP reflects deactivation at the expiration of the current operating licenses. The Nuclear Regulatory Commission ("NRC") operating license for Waterford 3 and Grand Gulf will expire in 2044, and the license for River Bend will expire in 2045, all outside of the IRP planning Horizon. However, ELL's portion of Entergy Arkansas's ANO Unit 1 and ANO Unit 2 are currently assumed to become unavailable in 2034 and 2038, respectively, to align with the current operating license expirations. Entergy's Nuclear group has not yet begun its license extension review process for these nuclear units, and some degree of risk exists that an operating license extension will not be granted under the NRC's Subsequent License Renewal ("SLR") process for units requesting extended operations from 60 years to 80 years. This planning assumption results in decreased base load capacity over the planning horizon as these units reach the expected end of their licensed lives. These assumptions are discussed in greater detail in Chapter 5 of this report.

It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service.[14] As planned deactivation dates near, a significant equipment failure occurs, or operating performance diminishes, a reassessment of assumptions may be required. Unit-specific portfolio decisions, e.g., sustainability investments, environmental compliance investments (like those contemplated in the CSAPR sub-section of the Environmental section of this IRP), or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, the reliability of the system, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation, and relative economics. Accordingly, ELL's IRP seeks to retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

Planned Resources

In its 2020 Request for Proposals for Solar Photovoltaic Resources, ELL sought up to 300 MW of solar generation to add to its resource portfolio. Out of this competitive solicitation, ELL selected three resources: Sunlight Road, a 50 MW solar resource located in Washington Parish, Vacherie, a 150 MW solar resource located in St. James Parish, and St. Jacques, a 150 MW solar resource located in St. James Parish. Additionally, ELL received an unsolicited offer for, and selected, Elizabeth, a 125 MW solar resource located in Allen Parish. ELL filed for certification of these resources at the LPSC in Docket No. U-36190 in November of 2021, they were approved by the LPSC in September of 2022, and are expected to be online in the 2024-25 timeframe.

[14] LPSC Order R-34407 details the relevant considerations and analyses utilities must assess before making a decision to retire or deactivate a unit and outlines the Commission's procedural requirements related to the same. .

Additionally, in its 2021 Request for Proposals for Solar Photovoltaic Resources, ELL sought up to 600 MW of solar generation to add to its resource portfolio. The filing that seeks certification of 224 MW of solar resources, including the resource that resulted from this RFP is currently pending in Docket No. U-36685. Furthermore, ELL has an ongoing 2022 Request for Proposal for Renewable Resources which is seeking up to 1,500 MWs of solar generation, and additional wind generation. Out of this competitive solicitation, ELL has made selections, is currently negotiating with counterparties, and intends to seek certification of all contracted for resources in late 2023 or early 2024. Finally, ELL has also sought the Commission's approval to acquire up to 3,000 MW of additional solar resources in Docket U-36697 coupled with a proposed alternative market-based mechanism process to allow for more timely procurement of such resources.

In July 2021, ELL filed an application in LPSC Docket No. U-36105 seeking approval for Power Through, a turnkey backup generation product offering of natural gas-fired distributed energy resources ("DER") to be deployed across the Company's service area. The Power Through offering will provide up to 150 MW of distributed generation, including 30 MW reserved for a pilot program consisting of solar and battery installations. Power Through will offer energy resiliency as a service for commercial and industrial customers via 100 kW – 10 MW DERs installed in front of a host customer's meter. These DERs will serve the dual functions of 1) meeting a portion of ELL's capacity and energy needs by delivering power to the grid when favorable market conditions exist, and 2) meeting the backup power needs of host customers during grid outages (e.g. in the aftermath of a hurricane or other weather event). The ELL Power Through program was approved by the LPSC in September of 2022, and the DERs are expected to be operational over the next several years.

While ELL's Updated Data Assumptions filing included a planned resource identified as the "2027 ELL CT", ELL has since modified this assumption and did not include it as a planned resource in the analysis provided in this Report.

Under the assumption that the planned resources described above proceed as planned, the 2023 IRP reflects a total of approximately 11,901 MW of resources in ELL's portfolio by 2026 on an effective capacity basis.[15] The diversity of ELL's currently planned resource portfolio in 2026 is shown in Figure 7 below.

[15] In alignment with MISO's MTEP 21 Future report, an effective capacity for solar resources of 48% of installed capacity in 2026 is used. A 16.3% capacity credit for wind resources is used, which algins with MISO's 2021-2022 Wind Capacity Credit report. For conventional resources, a 100% capacity credit is used. LMRs receive peak hour capability plus reserve margin and transmission losses. See Chapter 5 for more in-depth discussion on effective capacity.

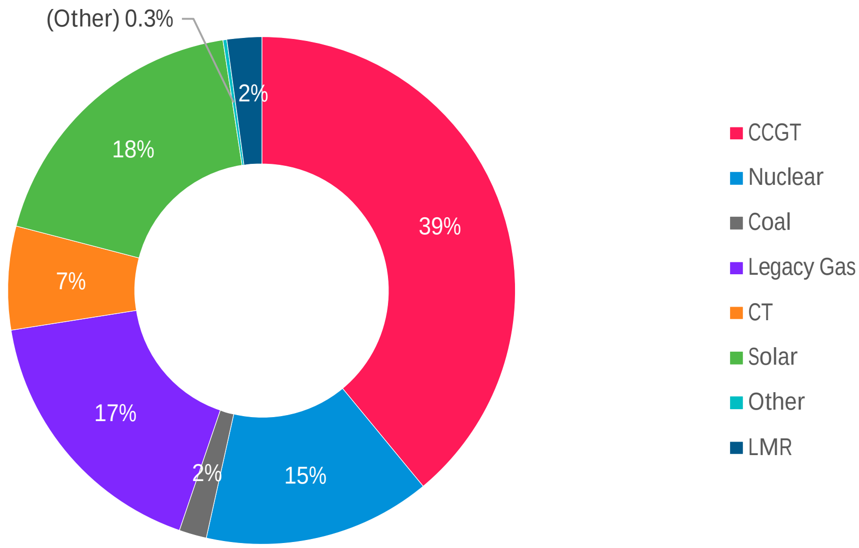


Figure 7: Entergy Louisiana 2026 Capacity Mix

Environmental Considerations

Entergy (along with its subsidiaries such as ELL) aspires to be an industry leader in protecting the environment. Environmental laws, regulations, and orders affect many areas of the Company's business, including restrictions on hazardous and toxic materials, air and water emissions, and waste disposal. ELL is committed to meeting or surpassing compliance with environmental and all applicable regulatory requirements and enhancing the communities it serves.

ELL strives to minimize any potential adverse effects of its activities on the local communities it serves, including the communities of its low-income customers. ELL considers environmental impacts in its policies and planning to minimize adverse environmental effects and to sustain its communities. ELL maintains open communication and seeks opportunities to partner with its stakeholders on environmental concerns.

To that end, the following provides an example of measures that ELL has taken regarding potential public health impacts and environmental considerations. In developing new generation, ELL identifies candidate sites and then conducts an evaluation of environmental factors and land use considerations for each site and its surroundings. This evaluation considers the presence of wetland areas, existing water quality in nearby water bodies, the potential presence of threatened or endangered species, and ambient air quality. Many of these factors are similar to the environmental indicators considered by the EPA EJSCREEN tool.[16] In addition, ELL conducts

[16] It should be noted that the EPA's EJSCREEN tool is used only to evaluate resources to be located at a specific, known location. The IRP optimized portfolios do not contain locational-specific assumptions such that use of the EJSCREEN tool is appropriate as part of the IRP.

environmental due diligence reviews to identify any existing environmental conditions at or near a proposed site for generation development. ELL continues to review and analyze best practices related to potential public health impacts and environmental considerations, including the use of EJSCREEN and other beneficial tools in planning for the future.

A more robust discussion of environmental considerations related to the IRP process is contained in the Inputs and Assumptions section within Chapter 4.

Customer Preferences and Long-term Planning

With advancements in technology and evolving priorities, both within and outside of the traditional utility framework, customer expectations will continue to change. Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in EE standards. ELL approaches EE with the broader goal of enhancing the generation, delivery, and use of energy, recognizing that a well-designed electric system, with the proper mix of generating resources, is just as important to reducing customer costs and bills as are programs aimed at educating customers on how to efficiently manage their usage.

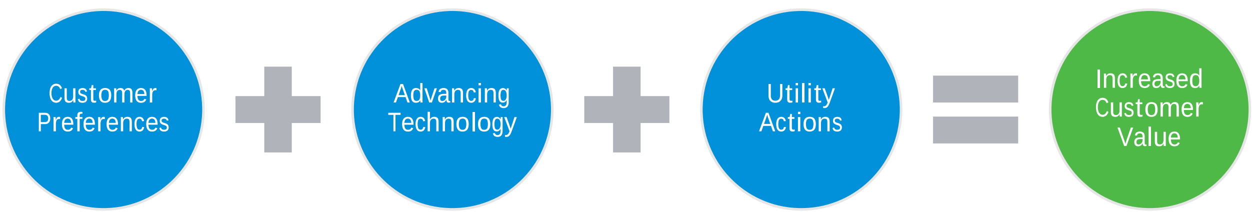


Figure 8: Changes and Opportunities Within the Utility Industry

Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived. As reflected in ELL's AMI proceeding in Docket No. U-34320, ELL's deployment of AMI is in response to ever-evolving customer expectations regarding the provision of electric service and technological innovation that is changing the way energy is supplied and distributed. ELL's interest is in actively engaging its customers to obtain a better sense of those expectations and the ways in which ELL can bring offerings to the marketplace to meet those expectations.

Increasingly, ELL customers are becoming more interested in sourcing their power from cleaner, more sustainable sources of energy, with a clear preference for renewable resources like solar. As mentioned earlier, ELL's green pricing and green tariff offerings provide participating customers the ability to subscribe directly to output from renewable sources, which have been, or will be, acquired to serve and benefit all customers consistent with ELL and the LPSC's long-term planning objectives, while avoiding the financial and operational risks associated with building or contracting for their own facilities.

ELL is focused on achieving a better understanding of these evolving customer preferences, and the IRP is one set of input information ELL can leverage to help accomplish that goal. That understanding will allow ELL to:

1. Develop a comprehensive outlook on the future utility environment so ELL can more effectively anticipate, and plan for, the future energy needs of its customers and region.
2. Incorporate new, smart technologies and advanced analytics to better assess where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid.
3. Continue to seek cost-effective renewable resource additions to ELL's portfolio to support and expand offerings of renewable energy to interested customers.

Advancing Technology – Technological advancements provide the energy industry increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs and to partner with customers to accomplish those shared objectives. From improving the reliability and efficiency of energy production and delivery of that energy to customers, to more customer facing opportunities, like storage, conservation, and AMI-enabled options, these innovations can strengthen reliability and increase affordability for the homes, businesses, industries, and communities that ELL serves. These new technologies also support the continued development and expansion of sustainability efforts while addressing ELL's long-term planning objectives, outlined in further detail below.

The deployment of advanced meters and development of smart energy grids, for example, are enabling the entire utility industry to better understand the new and changing ways in which customers are using energy. This allows energy companies to make more informed decisions and provide tailored customer solutions through enhancements to electric infrastructure and the adoption of new products and services.

Increased Customer Value – By combining an understanding of what customers want with sound and comprehensive planning, ELL can deliver the type of service customers expect while continuing to address the utility-wide planning objectives of cost, reliability, risk, and sustainability. Increasing the array of alternatives provides an opportunity to better meet ELL's planning principles by providing a diverse portfolio of resources to meet long-term service requirements. A diverse portfolio mitigates customer exposure to price volatility associated with uncertainties in fuel and power purchase costs and risks that may occur through a concentration of portfolio attributes such as technology, location, or supply channels. Additionally, by taking advantage of increased and evolving opportunities, ELL continues its effort of modernizing its supply portfolio.

Innovation

ELL strives to solve critical customer frictions for residential, commercial, and industrial customers by building new products and services. Every customer is an integral part of ELL's success. ELL collaborates with its customers, partners, and colleagues to build a more robust, sustainable power network for today and future generations.

For example, with the growing opportunity and challenges that will come with electrification of transportation in the coming years, ELL expects its customers to increasingly electrify as more vehicle models become available and their prices reach parity with, or become less expensive than, internal combustion engine alternatives. Specific to the commercial space, ELL also sees a growing number of organizations exploring electric vehicle alternatives in order to help them reach their internal sustainability goals. ELL's forecasting processes include assumptions around increased energy usage tied to electrification, which is discussed in greater detail in Chapter 4.

ELL looks to enable opportunities in this space and expects to remain customer centric with its approach. Accordingly, ELL will be exploring solutions in the future relating to fleet electrification, public charging, and workplace and residential charging. In parallel, ELL is committed to having the resources and infrastructure in place to support these initiatives.

Another example of ELL's efforts includes being one of the founding members of The Electric Highway Coalition. The collective group of utilities announced a plan in March 2021 to enable electric vehicle drivers seamless travel across major regions of the country through a network of direct current fast chargers for electric vehicles. The companies are each taking steps to provide EV charging solutions within their respective service territories. Since the March announcement, the coalition already has doubled in size with commitments from other utility partners.

MISO Resource Adequacy ("RA") & Planning Reserve Requirements

MISO RA Requirements – As a load serving entity ("LSE") within MISO since 2013, ELL is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. To this end, ELL must maintain the proper type, location, level of control, and amount of capacity in its portfolio. With respect to the amount of capacity, two considerations are relevant:

1. MISO Resource Adequacy Requirements
2. Long-Term Planning Reserve Margin Targets

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient short-term capacity, through the procurement of ZRCs equal to their seasonal PRMRs, in order to ensure regional reliability. ZRCs are provided by both supply-side generation and demand-side alternatives. An LSE's PRMRs are based on its seasonal forecasted peak load coincident with MISO's seasonal forecasted peak load, plus a seasonal planning reserve margin, which is established by MISO annually, for the MISO footprint.

Contrary to the apparent belief of several Louisiana electric cooperatives, MISO's annual planning resource auction is not and should not be relied upon as a long-term source of capacity. MISO is not authorized to build or procure generating capacity to ensure there is an ample supply; MISO relies on LSEs and retail regulators like the LPSC to ensure each LSE has an appropriate amount of long-term physical capacity to support resource adequacy. If ZRCs submitted in the planning auction are less than the PRMR, the planning auction will clear at CONE and MISO will manage subsequent operational generation shortfalls induced by resource inadequacy through controlled load sheds as needed. Notably, ZRCs are not sold through the planning auction. Rather, utilities participating in the planning auction merely make a payment, up to CONE, that fulfills their obligations vis-a-vis their respective PRMRs. It is possible that utilities may make such a payment and still not have secured sufficient capacity from identifiable, physical resources to support their loads. This increases the risk of load shed events. And the risk of such load sheds is not limited to the utilities whose overreliance on the MISO annual auction contributed to the operational shortfall. Rather, the load sheds potentially adversely affect customers across the state, including those customers served by utilities that have deployed reasonable long-term resources sufficient to serve their load and collected the resulting costs from such customers in rates. For this reason, reasonable and responsible resource planning requires a long-term plan for physical resources, and plans to rely on the MISO annual auction as a source of that capacity are misguided and harmful to the interests of electricity customers across the state.

Under MISO's Resource Adequacy process, the MISO-wide seasonal planning reserve margins are determined annually by November 1st prior to the upcoming planning year (June – May). Additionally, through MISO's annual Resource Adequacy process, MISO determines the amount of physical capacity needed within a particular region or LRZ based on load requirements, capability of existing generation, and import capability of the LRZ. Those capacity requirements are referred to as the Local Clearing Requirement ("LCR") for the LRZ for each season in the Planning Year. Through MISO's methodology for setting each LRZ's LCR, MISO has sent signals emphasizing the need for in-zone resources to contribute to LRZ resource adequacy.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually for four seasons and apply only to the upcoming year. Similarly, the value of seasonal ZRCs, as determined annually by the seasonal auction clearing prices that occur in MISO's Planning Resource Auction, apply only to the upcoming year. Both the level of required ZRCs and the value of those ZRCs are subject to change from year to year. In particular, the value of ZRCs can change quickly as a result of variables such as changes in forecasted load, transmission import/export constraints, market participant bidding strategies, the availability of accredited generation capacity within MISO and a specific LRZ, or an LRZ's LCR. For example, if existing LRZ 9 generation is deactivated and replaced with generation outside of LRZ 9, there will be an increased risk of higher ZRC prices due to potentially insufficient in-zone generation to meet the LRZ 9 Local Clearing Requirement. ELL forecasts that absent planned physical generating resource additions beyond what had been proposed to and/or certified by the LPSC at the time of the Data Assumptions Filing, the current LRZ 9 generation surplus above its LCR is expected to erode by the 2025/2026 planning year, largely due to load growth and existing unit deactivations driven by age, economics, contract expirations, and environmental regulations, which, as previously stated, would put the entirety of LRZ 9 at risk of clearing at the CONE prices within future MISO PRAs, significantly increasing costs and jeopardizing future reliability for all within the region. As noted above, the recently released PRA results for the 2023/2024 MISO Planning Year show that the capacity surplus in MISO South decreased by nearly 40% from last year's auction to this year's and capacity in the South exceeds requirements by just 5.1%. The recent experience of MISO North, which has a surplus of 4.7% in this year's auction but, just last year, had every LRZ clear at CONE, shows that the current MISO South surplus of 5.1% is sufficiently narrow that it could easily become a deficit in a single year. This year's PRA results also include increased prices in LRZ 9 (including prices for the Winter and Fall that are significantly higher than all other zones), providing further evidence of the reduced availability of capacity within the zone. The projected capacity deficits shown in the chart below could be even greater due to load growth, the new MISO seasonal construct and accreditation changes, and/or if CSAPR or other environmental regulations trigger earlier unit deactivations. By contrast, the projected capacity deficit could be mitigated if the LPSC requires all LPSC-jurisdictional LSEs to support new or existing load with physical capacity and ensure resource adequacy.

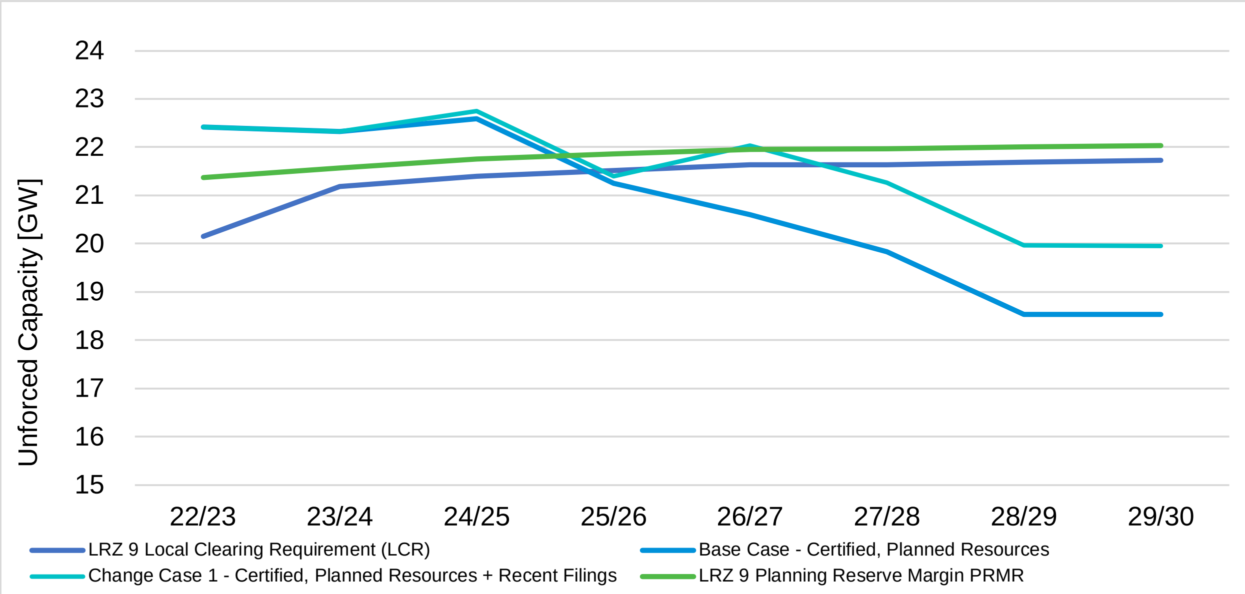


Figure 9: LRZ 9 Forecasted Unforced Capacity Position

MISO market constructs, rules, and methodologies continue to evolve, including items that impact Resource Adequacy requirements and capacity accreditation. In November of 2021, MISO filed a proposal at the FERC that shifts the current annual Resource Adequacy construct to a seasonal construct including modification to the way requirements and accreditation are derived. FERC accepted MISO's proposed tariff changes in August of 2022, and these changes have been implemented for the 2023/2024 PY. Given that these tariff changes were accepted late in the ELL IRP process, ELL's 2023 IRP will continue to be based on an annual construct, including the information contained throughout this report. Notwithstanding this, it is important to note that ELL's current annual solar and battery capacity credit assumptions do account for the reliability contribution of these resources across all times of the year, not just the summer peak period.

In light of the recent tariff changes, ELL has adjusted generation planned outage scheduling practices to protect unit accreditation ratings and has revised PRA unit offer strategies to minimize PRA costs. ELL's long-term planning approach is currently being re-evaluated to determine what updates are needed to align with MISO's new resource adequacy construct. Additionally, as capacity accreditation for non-thermal resources, such as solar, wind, and battery, is updated by MISO and approved by FERC (assuming FERC approval), ELL will align its long-term planning strategies with these updates as well. With anticipated increases in renewable penetration, MISO[17] and ELL anticipate that the capacity value contribution of solar and wind will evolve.

[17] MISO, *MISO's Renewable Integration Impact Assessment (RIIA),* MISO Energy (February 2021), *available at* https://cdn.misoenergy.org/RIIA Summary Report520051.pdf

As an LSE within MISO, ELL is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. Among other things, the resource portfolio must include the appropriate amount and type of generation to reliably support ELL's load. While the focus of resource additions will be on renewable resources, utilities must ensure they obtain or maintain an appropriate amount of dispatchable generation to support needs created by intermittent renewable resources. Moreover, the development of new capacity resources is a multi-year process, and load forecasts increase in their degree of uncertainty the further out into the future the forecast applies. Therefore, ELL plans beyond the immediate year requirements outlined by MISO's Resource Adequacy process. However, as discussed below, ELL's long-term reserve margin target is informed by MISO's Resource Adequacy construct.

It should also be noted that MISO's resource adequacy construct is still evolving. Currently, MISO is conducting a stakeholder process on a proposal to replace the vertical demand curve with a sloped demand curve in the PRA. ELL is engaged and participating in this stakeholder process. If and as any proposal relating to a sloped demand curve is submitted to and approved by FERC, ELL will adapt its long-term planning efforts and strategies to align with the resulting market design change.

Long-Term PRM Targets – Although the MISO Resource Adequacy process establishes minimum seasonal requirements that must be met in the prompt-year and are updated annually, for various reasons, including that developing new resources requires substantially more lead time than one year and entails substantial risk, it does not provide an appropriate basis for determining ELL's long-term resource needs. Moreover, relying on the MISO Planning Resource Auction as a source of generation capacity to meet customers' long-term power needs would unnecessarily expose customers to cost and reliability risk. For these reasons, ELL employs a more stable approach that is better suited for long-term planning to meet its long-term planning objectives. ELL's planning reserve margin reflects a long-term point of view that is intended, in part, to provide a buffer, or margin, above peak load to maintain reliable service during unplanned events such as higher than expected peak loads, longer than expected lead time to develop new resources, and unplanned outages of units committed to supply energy into the MISO market.

ELL's long-term planning construct is informed by a Loss of Load Expectation analysis which draws upon ELL's experience participating in MISO. The result of that analysis was a decision, in 2020, to change from the prior 12% reserve margin based on installed capacity ratings and forecasted non-coincident peak to a 12.69% reserve margin based on unforced capacity ratings and forecasted peak coincident to MISO. The changes in the planning reserve margin are intended to maintain the 1-day-in-10-year loss of load expectation level of reliability in the MISO region over the long-term planning horizon while considering long-term uncertainty related to load forecast, weather impacts, and available supply. Load forecast uncertainty was assessed by modeling a distribution based on economic uncertainty and corresponding forecast error associated with a four-year period, which was the assumed minimum lead time required to plan and install new capacity. Weather uncertainty was captured through application of historical weather shapes to forecasted peak demand and energy volumes. Supply-side resource forced outage rates for Entergy units was based on unit level historical operating data. For non-Entergy resources, MISO class average forced outage rates were used. ELL's current long-term planning construct is based on an annual target derived using the 12.69% reserve margin applied to ELL's summer peak load coincident with MISO. As discussed above, FERC recently approved MISO moving from its current annual PRA construct to a seasonal construct. With FERC having approved this change, ELL will continue to evaluate what changes, if any, are needed to the long-term planning construct.

Resource Needs

A number of factors are considered and evaluated in order to understand and determine ELL's resource needs:

Long-Term Capacity Requirements – ELL is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions and load growth into account, the long-term deficit is expected to exceed 510 MW by 2027. This need may grow to over 5,100 MW by the end of the planning horizon. The below figure shows ELL's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to ELL's peak load-plus-reserve-margin target. An assumption for future energy savings due to continued and expanded EE programs is included in the peak load. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

Figure 10: ELL Capacity Position

Energy Requirements – In addition to addressing long-term capacity requirements, ELL regularly assesses how its generating fleet is expected to align with its long-term energy requirements. Based on the current planning model projections and absent any changes to deactivation assumptions, approved resource additions, and renewable resources solicited in ELL's 2021 and 2022 Solar and Renewable RFPs (identified as "Planned Solar Capacity" in

Figure 10 above),[18] ELL is expected to fall short of effectively meeting its long-term energy requirements without significantly relying on other Entergy operating companies and the MISO market. However, the amount of energy produced by owned generation is subject to change based on fuel prices, market conditions, and unit operations.

Through the technology assessment and the IRP analytics, ELL evaluates energy-producing resources like renewable energy and dispatchable natural gas resources to meet both capacity and energy requirements over the long-term planning horizon. As resources deactivate and capacity requirements increase, ELL will look to balance energy producing and peaking generation to meet customer requirements effectively and efficiently.

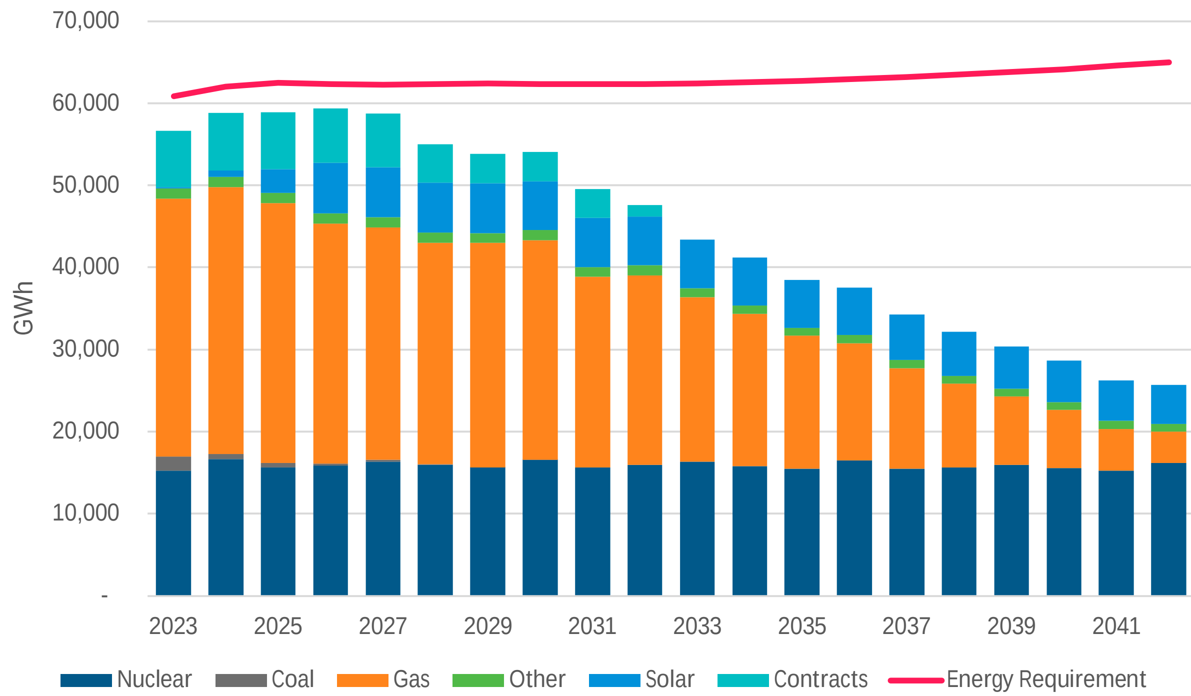


Figure 11: ELL Energy Requirements

Customer Usage – Of course, both capacity and energy resource needs are driven by customers' consumption and preferences. The type, size, and timing of future resource needs may be affected as customers gain additional resources to manage consumption, such as those that will be enhanced by AMI or those affected by increased accessibility to rooftop solar or battery storage technology.

ELL's long-term planning process and the evaluation outlined in this IRP helps inform how ELL can meet its future capacity and energy requirements needed to continue reliably serving its

[18] It is important to note that it is possible that planned additions may not come to fruition to provide the level of capacity solicited from RFPs. RFP solicitations identify a targeted amount of capacity. It is possible that selections from RFPs may not yield the solicited level of capacity, or that proposals selected do not ultimately come to fruition due to a variety of factors, several of which are beyond ELL's control.

customers. Consistent with the resource planning objectives outlined in Chapter 2, ELL's planning approach is to employ a diverse portfolio of energy generation resource alternatives, located in relatively close proximity to customer load with flexible attributes to help provide sufficient capacity during peak demand periods as well as adequate reserves. Given the primary objective of risk mitigation, these practices ensure that ELL is able to continue providing safe and reliable service at a just and reasonable cost for its customers.

Supply Role Needs – As discussed previously in the existing resource section, ELL's CCGT generation fleet provides customers base load and load-following energy supply**.** In ELL's 2019 IRP, it was assumed that the useful life for CTs and CCGTs was 30 years. Since that time, ELL conducted a detailed analysis on the expected remaining useful life of those resources. The result of that analysis concludes that ELL's CTs and CCGTs are generally assumed to have a remaining useful life of longer than 30 years and most are assumed to operate beyond the end of the 2023 IRP study period (2042). ELL's 2023 IRP reflects the useful life assumptions noted above. These deactivation assumptions result in less than a 1 GW decrease in base load and load following capacity within the planning horizon. As noted previously, ELL is continually assessing these units in order to refine the useful life assumptions based on historical operations and current conditions of the facilities.

ELL's current generating fleet also includes Coal, Legacy Gas, CT, Nuclear, and PPAs of varying technologies that reliability serves ELL's customer demand over seasonal peaks. However, roughly 40% of this capacity will deactivate at varying times over the planning horizon. ELL has publicly announced its commitment to cease burning coal at all of its plants by 2030. Additionally, EAL has announced the planned deactivations of White Bluff 1&2 in 2028 and Independence 1 in 2030.

Locational Considerations – The location of resources can have a significant impact on the electric grid. Resources, both supply-side and demand-side, can have an impact on the pattern of power flowing on the transmission system and on the voltage at the substations in the vicinity of the resource. The addition of a generating resource injects power into the electric grid; this additional power might help alleviate congestion on the electric grid, but the incremental power might also result in thermal constraints that may have to be alleviated with transmission upgrades. The addition of resources may also add reactive power into the system which can provide voltage regulation. This effect on the electric grid is particularly beneficial for large industrial loads and other similar loads that impose reactive power demands. Deactivations of resources can similarly change the power flows through the electric grid and may result in overloads or voltage constraints, and any resource additions or replacements in lieu of resource deactivations may be strategically located on the electric grid to minimize any detrimental impacts. Finally, the location of resources also has a broader impact on the MISO capacity auction. A location within a LRZ allows a resource to contribute to the local clearing requirement of a LRZ in the MISO PRA.

Flexibility Considerations – The portfolio design analytics explore the value of renewable energy projects, energy storage, peaking, and CCGT capacity. Based on these analyses, the long-term planning horizon will include additions of renewable and possibly energy storage and other technologies to ELL's portfolio. As intermittent additions increase, as high capacity factor loads increase, and as ELL's legacy fleet deactivates, ELL also may see increased value in additional flexible peaking and quick-response capability more indicative of spinning technologies, such as Reciprocating Internal Combustion Engines ("RICE"), Aero-derivative CT technologies, and CCGTs as well. ELL continues to be committed to exploring clean, alternative fuel sources to ensure longevity of these resources.

ELL will continue to assess the likely increasing capacity, energy and operational flexibility required over the long-term planning horizon. This on-going assessment of the generation supply plan against dynamic factors like capacity requirements, operational requirements, grid reliability and evolving technologies will enable ELL to continually improve efficiencies to develop solutions to address its customers' needs while mitigating risk.

Transmission Planning

Transmission planning ensures that the transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") reliability standards, and related Southeastern Electric Reliability Council ("SERC") and ELL's local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since December 2013, ELL has been a Transmission Owning member of MISO, a Regional Transmission Organization ("RTO"). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit member-based organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. In cooperation with stakeholders, MISO manages 65,800 miles of high voltage transmission and 189,421 megawatts of power generating resources across its footprint. Since joining MISO, ELL has planned its transmission system in accordance with the MISO Tariff.

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). ELL is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 23 cycle. Participation in the MISO MTEP process is the method by which ELL's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owner's transmission plans which address issues more local in nature and are driven by the need to provide service safely and reliably to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Through these MTEP related activities, ELL works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. ELL's participation helps ensure that opportunities for system expansion that would provide benefits to ELL customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.

ELL's transmission planning is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the ELL transmission system is thoroughly studied to verify that it will continue to provide customers with reliable and safe service through compliance with all applicable NERC reliability standards as well as ELL's local planning criteria and guidelines.

These studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to develop projects and determine what, where, and when system upgrades are required to address any future reliability concerns. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, retirements of existing generation resources, implementation of new generating resources, the adequacy of new and existing substations to meet local load, the expected power flows on the bulk electric system, and the resulting impacts on the reliability of the ELL transmission system.

These reliability studies result in projects which are presented annually to the ELL Operating Committee and ultimately must be approved by ELL's President and CEO. Once approved, these reliability projects are submitted to MISO for regional study, to 1) verify that the reliability need exists, 2) verify that the proposed solutions solve the reliability need, and 3) provide stakeholders the opportunity to propose alternatives. Additionally, MISO performs other studies each year to consider planning issues including Market Efficiency Projects, Multi-Value Projects, and customer driven projects, such as those driven by generator interconnection requests, and opportunities for interregional projects with neighboring planning regions.

The result of the MISO MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP cycle lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors. Since joining MISO in 2013, ELL has submitted projects into MTEP 14 through MTEP 23. The ELL projects that were approved for inclusion in Appendix A of MISO's MTEP 16 thru MTEP 21 cycles are provided in Appendix F – Table 22 through Table 27, respectively. Also, submitted Target Appendix A projects for MTEP 22 and MTEP 23 are in Appendix F -Table 28 and

Table 29. These future transmission projects and other transmission plans developed during the next three years will be important inputs to consideration of future resource needs.

Integration of Transmission and Resource Planning – The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Optimal construction of generating resource and transmission facilities, both in terms of location and timing, and the continued maintenance of this integrated electric network is crucial to the functioning of an efficient and reliable electric network capable of delivering value to customers. Generating resources and the transmission grid serve complementary roles: while the transmission system conveys power to customers, the generating resources help meet the energy and capacity requirements of the grid. Moreover, like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting ELL's planning objectives of low cost, improved reliability, and reduced risk.

The continued evaluation and condition of ELL's generation fleet must be considered for integrated generation and transmission planning. ELL's planning assumption includes deactivation of existing generation resources during the planning horizon, which could have an impact on transmission reliability without proper siting of replacement generation. Likewise, the location of planned transmission facilities on the bulk electric system, particularly those at higher operating voltages, can have a significant impact on the siting, timing, size, and type of planned resources to address the generation needs of a particular area.

Distribution Planning & Grid Modernization – Through its distribution planning process, ELL's efforts will continue to maintain and improve the reliability of its distribution lines and its distribution line infrastructure, while aiming to minimize customer outages. Customers directly benefit from improvements in line maintenance, infrastructure, vegetation management, and substation reliability through reduced outages and outage duration. Customers also benefit from the reduction in costs from extending the life of distribution assets and minimizing maintenance costs with respect to those assets.

Additionally, ELL's grid modernization efforts are aimed at continually upgrading and redesigning grid infrastructure to facilitate adding new technologies and intelligent devices that facilitate safe multi-directional energy flows, automate operations, enable remote control, increase operational efficiency, improve quality of service, increase reliability and resiliency, and expand options for customers.

This modernized grid infrastructure, including enhanced communications networks that incorporate radio mesh networks, cellular and fiber optic links, is not only critical for day-to-day utility reliability needs but also to support the greater deployment of advanced meters and related infrastructure, DERs, and other technologies. ELL's objective is to achieve a modernized distribution system over time that also improves reliability to meet customers' evolving needs and expectations.

Integration of Transmission and Distribution Planning – While MISO operates an energy and ancillary services market, administers a Transmission Planning process and a resource adequacy process through an annual PRA, ELL, in its role as an LSE, must integrate resource, transmission, and distribution planning to ensure that energy can be supplied to customers in a manner that is reliable, affordable, and environmentally responsible.

As discussed above, distribution investment will enable the interconnection of DERs and impact the reliability of the system. Additionally, driven by customer specific sustainability goals, or economically offsetting wire investments, distributed generation may be deployed across the ELL service area. These investments impact the need for other transmission and generation investment.

Due to the interdependencies of the resource, transmission, and distribution long-term planning processes, coordinating and harmonizing these three planning processes is crucial to ensure that ELL's planning objectives of affordable cost, high reliability, and environmental stewardship are met.

Sustainability Goals

Entergy has been an industry leader in voluntary climate action for over two decades. In 2001, Entergy was the first U.S. utility to voluntarily limit its carbon dioxide emissions. After beating this target by more than twenty percent, Entergy renewed and strengthened this commitment twice and outperformed by eight percent its 2020 commitment to maintain carbon emissions from Entergy-owned facilities and controllable power purchases through 2020 at twenty percent below year 2000 levels.

Building on its longtime legacy of environmental stewardship, Entergy has enhanced its climate action strategy with near-term goals to achieve 50% carbon-free energy generating capacity by 2030 and to reduce the utility emission rate by 50 percent by 2030 in comparison to Entergy's emission rate from its baseline year of 2000, and a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. ELL intends to contribute to the company accomplishing these goals by working with its regulators and other stakeholders to balance reliability, affordability, and sustainability.

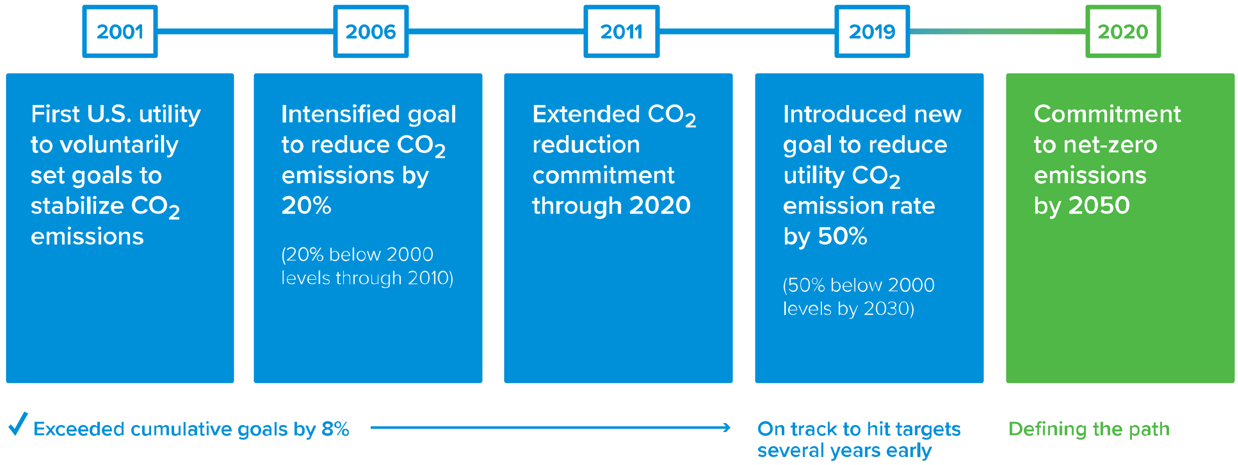


Figure 12: Entergy Climate Action Strategy

Entergy is taking action now toward a carbon-free future and expects to achieve its net-zero 2050 commitment by enhancing its portfolio transformation strategy with emerging technology options, working with customers, key suppliers and partners to advance new technologies necessary to reduce emissions, continuing to engage with partners and gain experience on enhancing natural systems like forests and wetlands that absorb carbon, and partnering with customers to electrify other sectors like transportation and industry for net emissions reductions and community benefits.

Additional details are available in ***Entergy's 2022 Integrated Report[19] and Entergy's 2022 Climate Report[20].***

[19] Entergy, *Pathway to Premier,* Entergy Corporation (2022), *available at* https://integratedreport.entergy.com/

[20] *Entergy's path to net-zero emissions and climate resilience* (2022), available at https://www.entergy.com/userfiles/content/environment/docs/2022-Climate.pdf

Chapter 4 Model Inputs and Assumptions

Summary

- ELL's reference forecast projects nearly flat growth in electricity consumption, with total energy growth of 0.35% annually and peak demand to growth of about 0.37% over the forecast horizon.
- ELL's technology assessment and fuel price forecasts have been updated.
- A third-party consultant was engaged to conduct an independent forecast of the achievable potential of DR and EE program types and DER technologies on the Company's system. The resulting forecasts were incorporated into the IRP's modeling process.

Resource Planning Considerations

Guided by its Resource Planning Objectives, ELL's resource planning process seeks to maintain a portfolio of resources that reliably meets customer power needs at a just and reasonable supply cost while minimizing risk exposure. The landscape within the electric utility industry is changing, and this IRP offers early insight for opportunities to respond to this evolving environment.

ELL recognizes the way customers consume energy and the type of energy they prefer is changing, therefore, the way the Company plans for, produces, and delivers the power on which customers rely must continue to change as well. ELL strives to have a planning process that provides for the flexibility needed to better respond to this constantly evolving environment.

Load Forecasting Methodology

Each year, ELL develops a forecast that is used for financial and resource planning. That forecast is often used as the Base Case or Reference Case for scenario analysis such as the IRP process. The Reference Case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view, which is then converted into hourly loads across each month. Future forecasts are then developed in a similar manner starting with monthly energy and then converting those levels to hourly loads. ELL developed two future forecasts in addition to the Reference Case forecast for the 2022 IRP. These are discussed in further detail below.

Load Forecast Uncertainty – Electric load in the long term will be affected by a range of factors, including:

1. Increases in EE, brought about by:
   a) Technological changes – lighting, heating, ventilation, and air conditioning ("HVAC"), appliance efficiency
   b) Structural changes – changes in building codes or state/national requirements[21]

[21] State requirements may include future policies and rules adopted in LPSC rulemakings such as the ongoing LPSC Docket No. R-31106.

   c) Other conservation measures – changes in personal behavior
2. Increased participation in DR and/or interruptible programs
3. Increased adoption of Electric Vehicles (Evs) in place of vehicles using internal combustion engines
4. Other electrification opportunities brought about by customers' reductions in natural gas usage in favor of electric end-use equipment
5. Levels of economic activity and growth, including expansion or contraction with large industrial load, as well as changes in population affecting residential and commercial classes
6. Potential adoption of behind-the-meter self-generation technologies (e.g., rooftop solar)
7. Changes in temperature and weather patterns over time.

Such factors may affect the levels of electricity consumption over the term of a study period as well as the hourly patterns of consumption across individual days. Annual peak loads could be higher or lower, and daily peaks could shift to later hours in the day. Uncertainties in these load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

Reference Case Energy Forecast – In accordance with the LPSC IRP Rules and the timeline provided by ELL at the start of this IRP cycle, the Reference Case forecast was developed in 2021 using a bottom-up approach by customer class: residential, commercial, industrial, and governmental. The forecast was developed using historical sales volumes, customer counts, and temperature inputs from January 2010 through December 2020, as well as future estimates for normal weather and EE. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, and estimates of future consumption growth from EVs and declines due to future rooftop solar adoption.

Regression Models for Non-Large Industrial Forecasts – The sales forecasts for the residential, commercial, small industrial, and governmental classes are developed individually using statistical regression software and a mix of historical data and forward-looking data. The historical data primarily includes monthly sales volumes by class and temperature data expressed as cooling degree days ("CDDs") and heating degree days ("HDDs"). Some of the forecasts also use historical indices for elements such as population, employment, and levels of end-use consumption for things such as heating/cooling, refrigeration, and lighting. These historical data are used in the Metrix ND® forecasting software, which is licensed from Itron. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and/or month-of-year, and those relationships are applied going forward to estimates of normal weather, economic factors, and/or month-of-year to develop the forecast. Explanatory variables are typically included in each class-level forecast model if the statistical significance is greater than 95%.

Residential Forecasts – Long-term residential forecast projects a slight increase in electricity consumption with 0.5%/yr. CAGR over the planning period. This forecasted increase is largely due to increasing customer counts due to household formation growth in ELL's service area as well as slightly positive average Use Per Customer ("UPC") growth.

Population projections come from IHS Markit[22] parish level data for ELL's service area. Overall, average annual kWh consumption per household is expected to grow slightly by 0.1%/yr. This UPC growth is driven mostly by increased electric vehicle adoption in the latter years of the forecast period, partially offset by increases in energy efficiency due to both organic adoption of newer, more efficient, technologies as well as from company sponsored EE programs.

The monthly model for residential UPC, taking into account expected efficiency is:

Residential UPC per day =

Heating Degree Days * Heating efficiency index * Heating coefficient +

Cooling Degree Days * Cooling efficiency index * Cooling coefficient +

other use coefficient * other use efficiency index

The residential forecasts use variables for individual months rather than using heating or cooling indices with monthly values across a year, allowing for greater precision with each monthly result. The regression uses actual historical weather, and the resulting coefficients are applied to estimates for normal weather levels in the future.

Trended Normal Weather - Analysis of historical data reveals that trends in average temperatures, expressed as CDDs and HDDs, have not been flat over the last few decades, and there is no evidence at this time to support an assumption of future temperatures remaining flat versus current (2020/2021) levels. As such, ELL has calculated a “trended normal” assumption for long-term energy planning using trends in 20-year rolling averages of monthly temperatures from 2001-2020, which are used in the Reference Case forecast. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility. The 20-year trended normal temperatures are built from hourly temperatures and are allocated to each calendar month. By 2042, the effect of the trended normal temperature assumption increases summer (July - September) residential and commercial energy consumption by 116 GWh (1.5%) and decreases winter (January, February, December) energy consumption by 46 GWh (-0.8%).

[22] *See,* IHS Markit Ltd. - www.ihsmarkit.com.

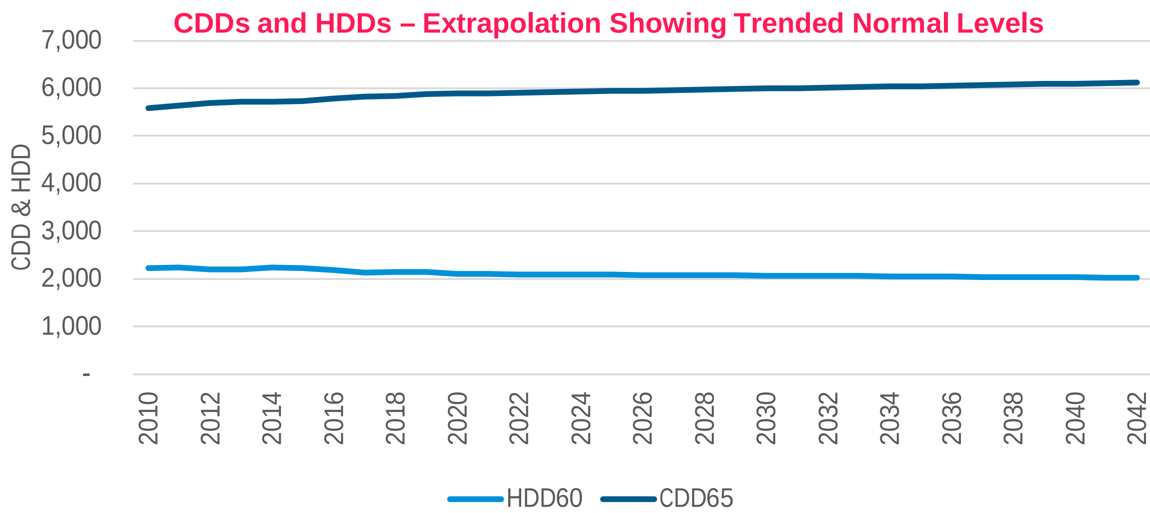


Figure 13: Changes and Opportunities Within the Utility Industry

Table 5: YoY Growth Residential

Year	Energy	Customers	UPC
2024	-0.1%	0.7%	-0.8%
2027	0.0%	0.6%	-0.6%
2030	-0.3%	0.4%	-0.7%
2033	0.3%	0.4%	-0.1%
2036	0.8%	0.3%	0.5%
2039	1.2%	0.2%	1.0%
2042	2.0%	0.2%	1.8%
2023-2042 CAGR	**0.5%**	**0.4%**	**0.1%**

Residential Forecast - ELL is expecting slightly positive residential customer count growth throughout the study period, with slight UPC declines in the near-term offsetting some of the MWh growth from increasing customer counts. Based on expected future growth in average residential UPC in ELL's service area, ELL is expected to have positive average residential UPC growth starting in the mid-2030s as increased adoption of electric vehicles begins to offset declining UPC from energy efficiency. For the period overall, the forecast is relatively flat with residential UPC growth of 0.1%/yr. for 2023-2042. The combined effect of slightly positive UPC growth and positive customer count growth leads to a net forecasted CAGR in residential energy of 0.5%/yr. The sales forecast includes a net 1.5% decrement to the residential sales, phased-in between 2020 and early 2022. The phase-in for these effects was based on the latest AMI deployment schedule available at the time of the forecast development plus a time allowance for the AMI-related customer information programs to show an effect.

See Table 5 showing the year-over-year changes and CAGRs in residential energy, customer counts, and UPC.

Commercial Forecast - Commercial use of electricity is forecasted to decrease slightly for 2023-2042 with a CAGR of -0.2%/yr. This decrease is driven by forecasted UPC decreases of -0.4%/yr. offset by slightly positive customer count growth of 0.2%/yr.

Table 6: YoY Growth Commercial

Year	Energy	Customers	UPC
2024	-0.1%	0.3%	-0.4%
2027	-0.5%	0.2%	-0.8%
2030	-0.5%	0.2%	-0.7%
2033	-0.3%	0.2%	-0.5%
2036	-0.2%	0.1%	-0.3%
2039	0.1%	0.0%	0.0%
2042	0.5%	0.0%	0.4%
2023-2042 CAGR	**-0.2%**	**0.2%**	**-0.4%**

The commercial sales forecast is developed using a similar methodology to the residential forecast with the exception that commercial sales are forecasted in total rather than by UPC because of the diversity of commercial customers, such as a large hospital versus a small office. Otherwise, the commercial forecast accounts for organic EE, primarily from HVAC and refrigeration, as well as Company-sponsored DSM programs discussed further below. The commercial forecast also includes the same type of AMI-related decrement phased-in from 2020-22 and then at the full 1.5% for the remainder of the study period.

Commercial Sales$_m$=

Heating Degree Days * Heating efficiency index * Heating coefficient$_m$ +

Cooling Degree Days * Cooling efficiency index * Cooling coefficient_m +

other use coefficient * other use efficiency index_m

See Table 6 for estimated year-over-year changes and CAGRs for commercial sales, commercial customer counts, and UCP.

Governmental Forecast - Governmental energy usage is forecasted to be relatively flat with only a slight increase for 2023-2042 with a CAGR of 0.2%/yr. This is due to a slight increase in customer counts and in UPC.

Small Industrial Forecast - The small industrial forecast includes industrial sales that are not forecasted individually in the large industrial forecast, described below. Forecasts are based on historical trends and IHS economic indices such as for labor force, refining, and chemicals. Small industrial sales can be volatile and are generally not temperature related.

Table 7: YoY Large Ind Growth

Year	Energy
2024	4.2%
2027	0.0%
2030	0.3%
2033	0.4%
2036	0.4%
2039	0.4%
2042	0.4%
2023-2042 CAGR	**0.62%**

Large Industrial Growth - The 2023-2042 CAGR for ELL's large industrial sales is 0.6%/yr. Due to their size, customers in the large industrial class are forecasted individually. Existing large industrial customers are forecasted based on historical usage, known or expected future outages, and information about expansions or contractions. Forecasts for new or prospective large industrial customers are based on information from the customer and from ELL's Economic Development team as to each customer's expected MW size, operating profile, and ramping schedule. The forecasts for new large customers are also risk-adjusted based on the customer's progress towards achieving commercial operation.

Table 7 shows the forecasted year-over-year growth in sales attributable to large industrial customers.

Energy Consumption by Class - ELL's energy consumption comes mostly from the industrial and residential customer classes who account for 56% and 24%, respectfully, of the forecasted sales for 2023. Commercial customers consume 19% of the energy with governmental customers consuming the remaining 1%.

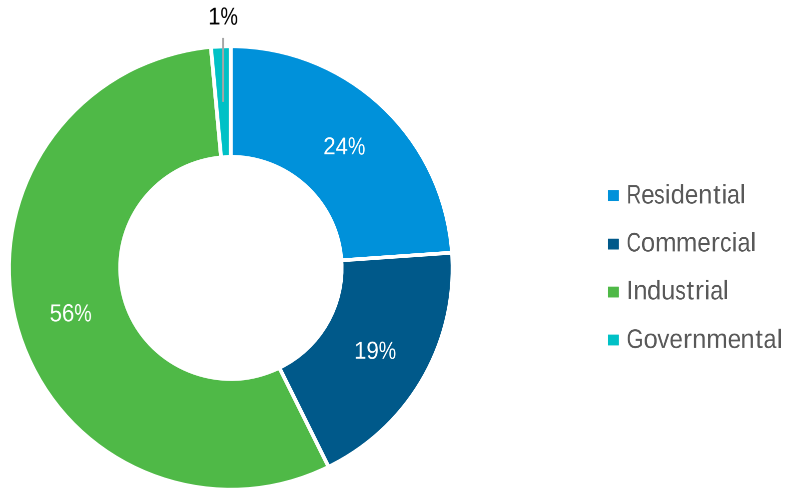


Figure 14: 2023 Energy Class Mix

This consumption mix by class is expected to remain largely unchanged throughout the study period. See Figure 15 below for the projected 2042 energy mix by customer class.

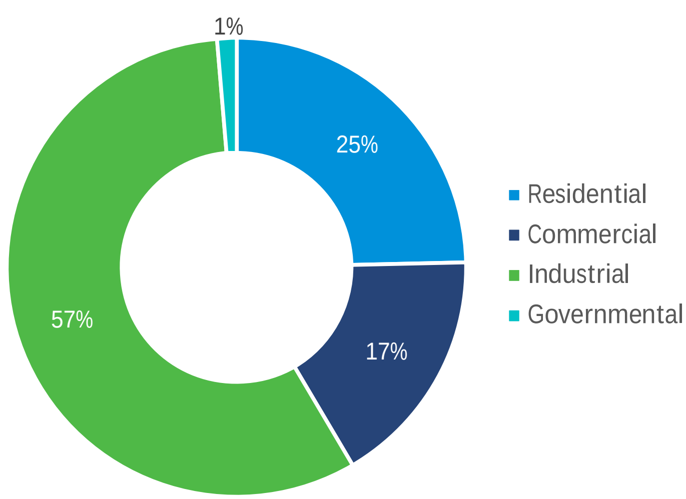


Figure 15: 2042 Energy Class Mix

Demand Side Management - ELL has had company-sponsored EE programs since late 2014, such as ones targeted for lighting, appliances, and HVAC efficiency.

DSM programs from one year have effects that carry forward into future years. As such, to develop an estimate of the DSM effects on the forecast, ELL starts with the historical (by year) DSM levels and develops an estimate of the cumulative effects of each year's programs on future years. See Figure 16 below.

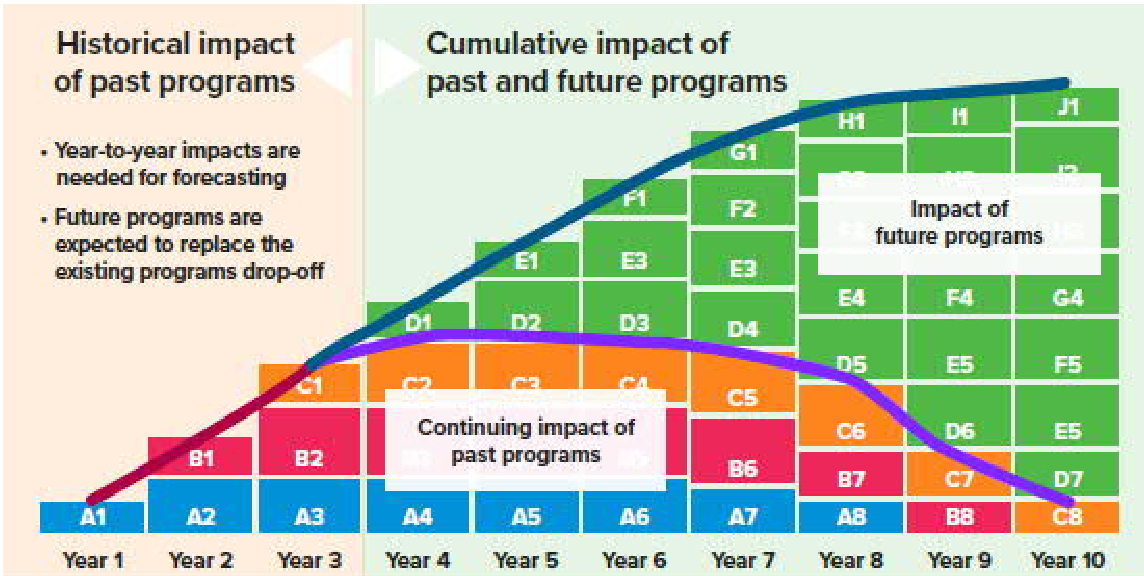


Figure 16: Chronological DSM Impacts

An add-back method was employed to develop the load forecast. See Figure 17 below. The add-back method takes the estimated cumulative historical volume of DSM savings in kWh and adds those amounts back to monthly billed-sales to develop a forecast as if there had never been DSM programs. From that forecast, the expected future levels of DSM are subtracted from the No-DSM forecast to arrive at the net forecast levels. This method was used for the Residential, Commercial and Small Industrial forecasts.

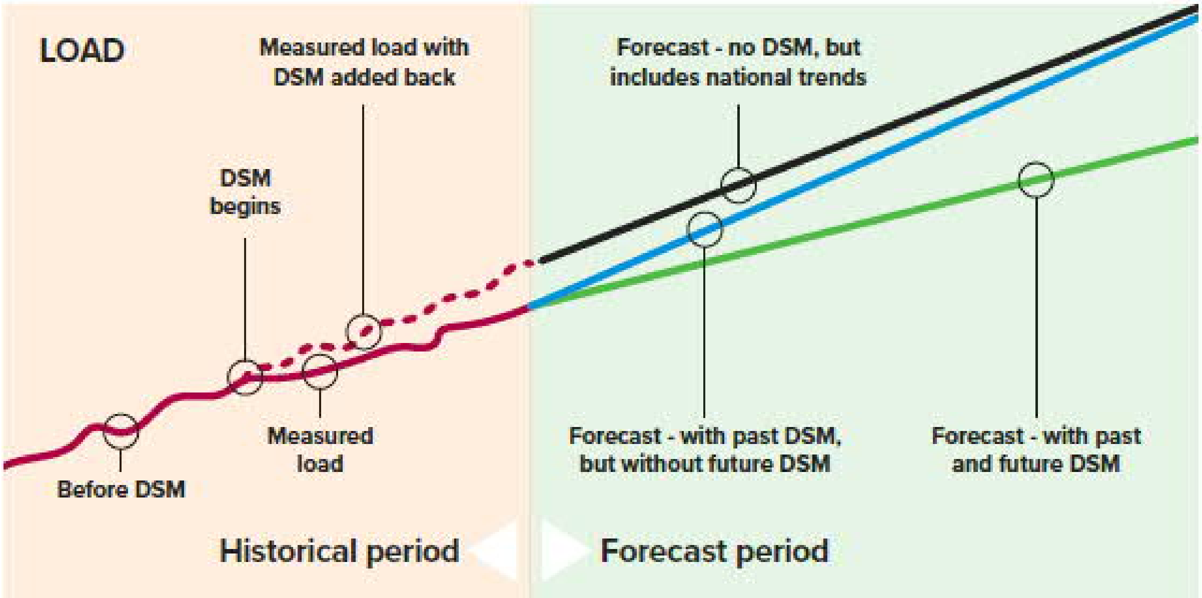


Figure 17: Add-Back Method

Using this methodology, new programs in future years are expected to reduce 0.1% of the total annual sales for ELL by 2023 in the IRP Reference Case forecast. Table 8 below shows ELL's expected incremental savings from pre-approved programs in the IRP Reference Case forecast. After 2023, there are assumptions around potential Phase II rules, with incremental savings levels increasing through 2031.

Table 8: Annual MWh Savings[23] (Incremental Assumptions)

	2023
Home Performance with Energy Star	5,264
Retail Lighting & Appliances	13,464
Income Qualified Solutions	1,257
High Efficiency AC Tune-Up	4,007
Manufactured Homes Pilot	2,190
Multifamily Solutions	3,923
School Kits & Education	1,354
Small Commercial Solutions	7,890
Large Commercial & Industrial Solutions	19,291

[23] Aligns with what was included in BP22.

Figure 18 below shows the estimated levels of cumulative annual energy savings included in the Reference Case forecast as a result of ELL's historically implemented DSM programs as well as savings from future DSM programs based on the incremental levels laid out in Table 8 above. DSM levels are expected to increase gradually through early 2030s, and then level off by mid-2030s and beyond.

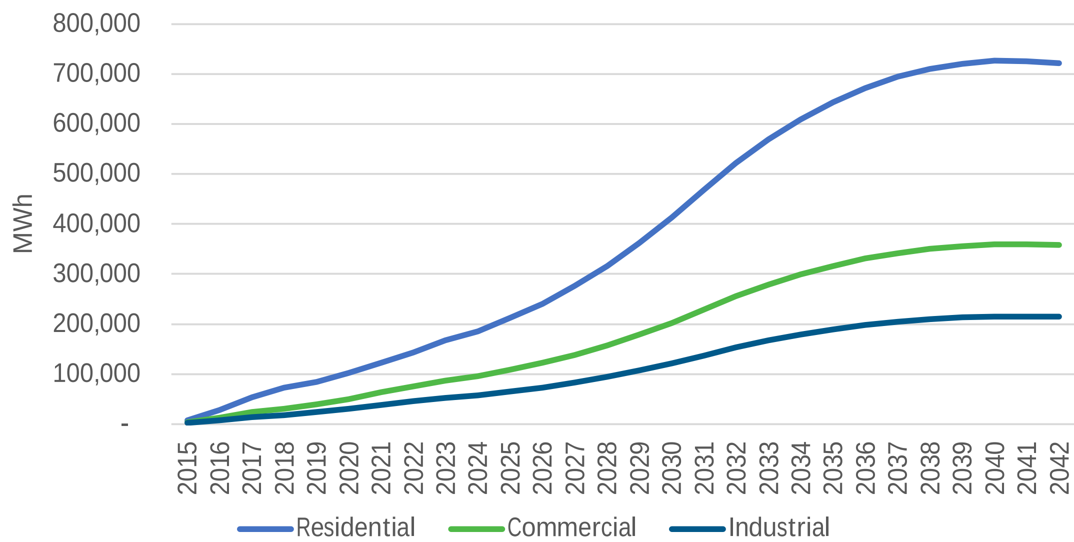


Figure 18: ELL Annual Energy Savings

Electrification and Conversions - The Reference Case forecast includes an assumption for sales growth as a result of programs sponsored by ELL to encourage electrification. The programs include electric forklifts, electric billboards, electricity-consuming services at truck stops, and agricultural irrigation pumps. Based on estimates from May 2021, these projects are expected to add nearly 335 GWh to commercial sales by 2042.

Hourly Load Forecast

Methodology - The load forecast is the result of combining three elements: the volumes from the monthly sales forecasts described above, the estimated monthly peak loads, and the hourly consumption profiles or shapes. These elements are developed using Itron's Metrix ND® software.

The forecasted monthly sales provide the monthly MWh volume for the load forecasts and reflect the expected effects of a few elements such as customer growth or declines, new large industrial customers, and EE. The monthly volumes are also used to develop the peak forecasts, which are estimated based on the historical relationship of peaks to energy while also considering the effects of weather. Hourly load shapes are developed from historical hourly load by customer class and in total. Those historical shapes are used along with historical weather data (HDD and CDD), calendar data to account for differences in usage on weekends or holidays, and other data to develop "typical load shapes" by customer class to be used for the forecast period.

The final step in producing the hourly load forecasts is to combine – or calibrate – the monthly energy, monthly peak, and the hourly shapes described above. Using Itron's Metrix LT® software, the energy volumes, the estimated peaks, and the typical hourly shapes are calibrated such that the three elements fit together in a way that the final result preserves the volume of energy while fitting it to the hourly profiles while maintaining, as closely as possible, the relationship of peak MW to monthly MWh. This process also reallocates the forecasted solar and EV energy using specific profile hours for each product technology. The result is a set of hourly load values, by class, for the forecast period from which a peak level can be determined. These hourly values are grossed up for Transmission and Distribution losses, which are calculated based on historical line losses. The Transmission and Distribution losses used in the IRP forecast are shown below.

Table 9: Transmission and Distribution Losses

	Legacy EGSL	Legacy ELL
Total Company T&D	3.8758%	3.9461%
Total Company Distribution	2.0199%	2.2219%

Reference Case Peak Comparison to Previous IRP - Since ELL's 2019 IRP cycle there have been decreases in the peak load forecast levels. This decrease is due to decreases in forecasted sales volumes across all customer classes between the two forecasts.

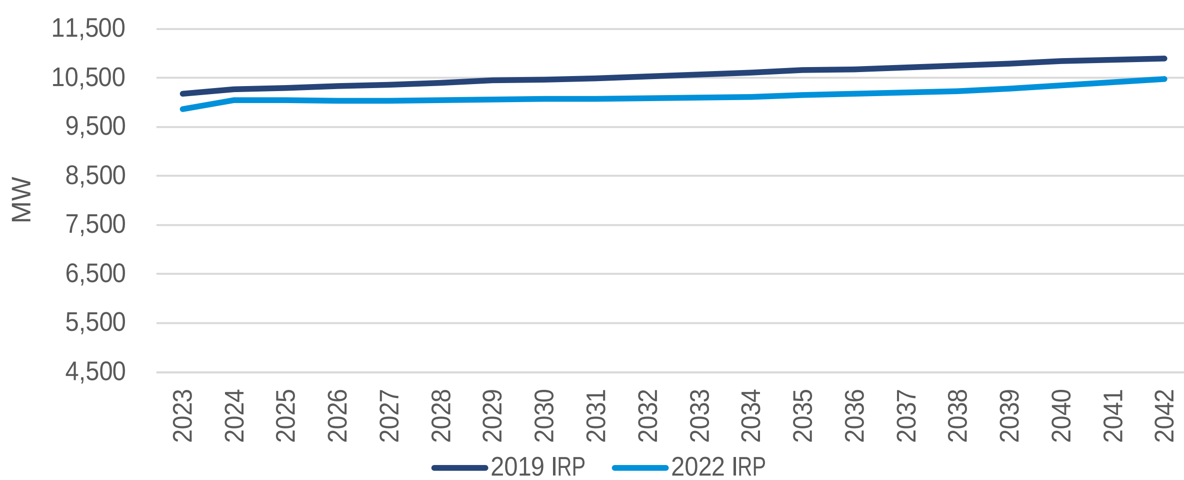


Figure 19: ELL IRP Reference Case Peaks by Version

IRP Scenarios - In previous IRP iterations, ELL would create "High" and "Low" sensitivity forecasts by adjusting the Reference Case forecasts up or down by a certain percentage to reflect a range of load possibilities. For this IRP iteration, a different approach was used in the development of the sensitivity forecasts for each Future by discerning the likely levers present based on the characteristics of each Future. Future 1 is the Reference Case forecast described above. See Table 10 below for a list of the levers and load effect in each Future scenario. Additional information for each Future used within the IRP analytics is described in Chapter 5.

Table 10: Load Levers by Future

	Item	Future 1: Reference Case	Future 2:	Future 3:
Narrative		Future 1 aligns with ELL's Reference Case Business Plan ("BP22") Uses ICF's Reference case BTM solar forecast instead of the BP22 solar forecast	Future 2 is a high growth scenario driven by growth in all customer classes, the main driver being transportation electrification and industrial growth related to process electrification. This growth is partially offset by increased BTM solar adoption.	Future 3 is a growth scenario driven by passenger vehicle electrification and industrial growth related to process electrification. This growth is partially offset by increased BTM solar adoption.
Res	Peaks Energy	Reference	Highest	Between Reference and Highest
Inputs	BTM Solar	ICF Reference	ICF High Solar + High Batteries	ICF High Solar + Reference Batteries
	Electric Vehicles (EVs)	Reference (2055)	Highest EV (2045 Passenger and Commercial Fleet)	High EV (2045 Passenger EV)
	Res. & Com. Growth	BP22	High Growth	Between Reference and High
	Refinery Utilization from EVs	BP22	Lowest	Between Reference and Lowest
	Industrial Growth	BP22	High	Between Reference and High

In Future 2, ELL sees strong growth from transportation electrification in both the passenger vehicle and commercial fleet space, whereby it's expected that ~100% of new passenger vehicle sales will be electric by 2045. Additionally, there is significant industrial growth from various types of process electrification driven by customers' desire to reduce their emissions at their facilities in ELL's footprint. This growth is partially offset by lower refinery utilization due to the prevalence of electric vehicles as well as an increased behind-the-meter (BTM) solar + battery forecast. The DR and EE programs provided by ICF were not included in the Future 2 load forecast, but rather selected based on positive net benefits or selected during capacity expansions, respectively. The methodology to select DR and EE programs in Future 2 will be discussed in Chapter 5.

In Future 3, ELL sees growth from transportation electrification only in the passenger vehicle space, whereby ~100% of new passenger vehicle sales will be electric by 2045. Additionally, there is industrial growth from process electrification driven by the customers' desire to reduce emissions at their facilities, however that growth is not as strong as the growth seen in Future 2. The reduction due to lower refinery utilization from EV growth is not as strong as Future 2. The BTM solar forecast is in line with Future 2, but the battery forecast is lower. In alignment with Future 2, Future 3 DR and EE programs provided by ICF were not included in the Future 2 load forecast, and followed the same methodology laid out in Future 2 above and further explained in chapter 5.

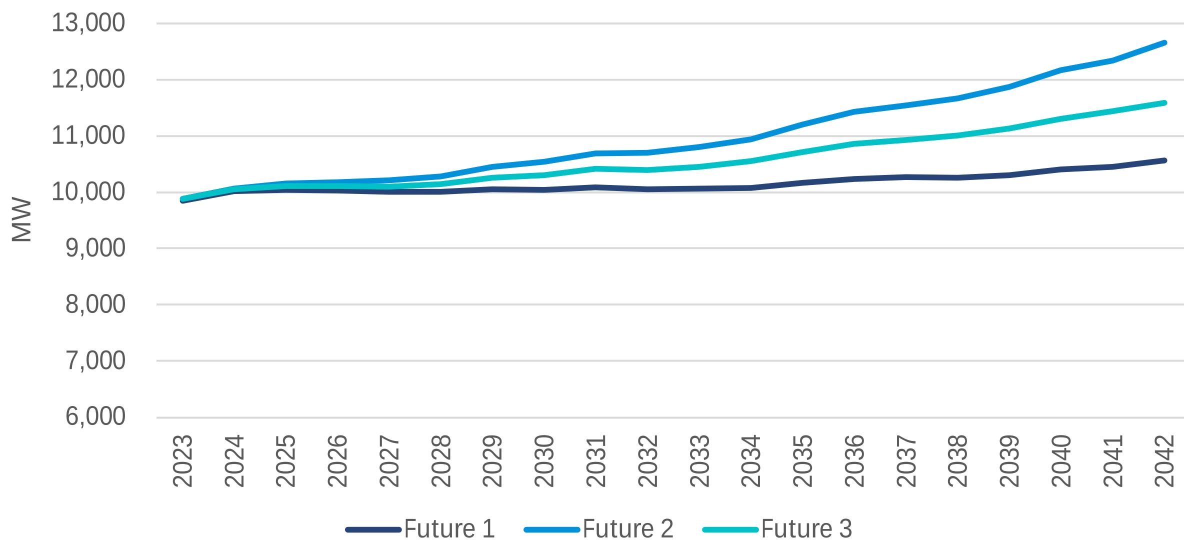


Figure 20: ELL IRP Peak Load Forecast by Future

Behind-the-meter Solar Generation - For all of the Futures scenarios, ICF produced behind-the-meter solar or solar plus battery impact estimates including a Reference Case level for Future 1, a High Solar + High Battery Case for Future 2, and a High Solar + Reference Battery for Future 3. Discussion of the methodology and assumptions for those can be found in Appendix L which contains the report produced by ICF.

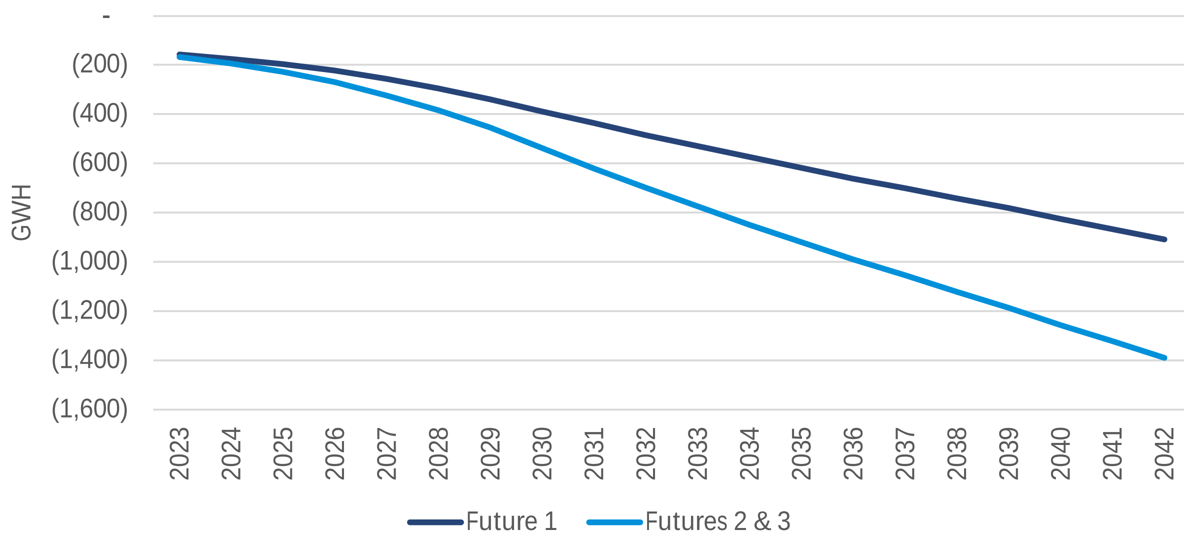


Figure 21: Residential & Commercial Solar Levels

Electric Vehicles - The Reference Case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs as well as growth in the numbers of total on-road vehicles over time as overall population is expected to continue to increase. The adoption over time is gradual based on an S-curve that assumes 99% of all passenger vehicle sales will be EVs by 2055. The effects for ELL are based on the estimated proportional numbers of vehicles in each jurisdiction within Entergy's footprint.

Overall, the additional GWh volumes from the EV forecast in the Reference Case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start increasing more in the mid-2030s. These levels were used for the EV forecast inputs for Future 1.

Futures 2 and 3 used more aggressive forecasts in which 100% of new passenger vehicle sales are expected to be EVs by 2045 while taking into account expected population growth and vehicle per capita increases. Additionally, Future 2 considers EV adoption for commercial. EV market share growth in new vehicle sales is based on an S-curve. Overall, the additional GWh volumes for the 2045 EV forecast is accelerating higher in the near-term compared to the Reference Case estimate and are adding 30% and 80% to ELL's sales totals by 2042, respectively.

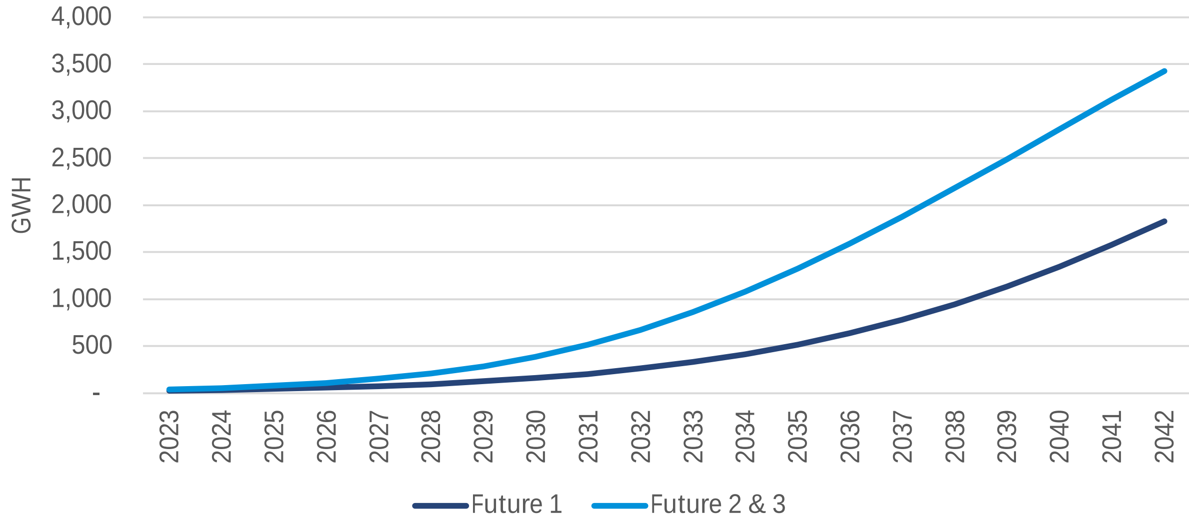


Figure 22: Residential EV Levels

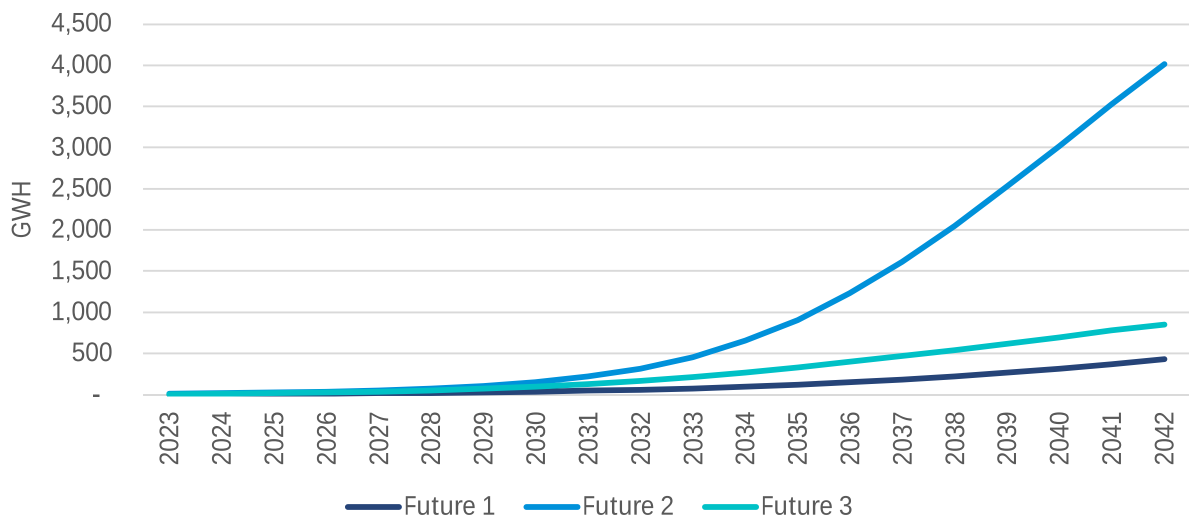


Figure 23: Commercial EV Levels

DSM (EE and DR) Measures - Discussion of the methodology and assumptions for EE and DR Measures can be found in Appendix L which contains the report produced by ICF.

Industrial Growth - Regarding industrial growth, Futures 2 and 3 have higher levels of growth than the Reference Case. The growth in Futures 2 and 3 are based on an analysis to determine the potential for Industrial process electrification in ELL's service area. Future 2 has roughly double the amount of process electrification compared to Future 3, however, both are well below the estimated potential for the service area.

Capacity Resource Options

Generation Technology Assessment - As part of its long-standing environmental stewardship and as the operator of one of the cleanest generation fleets in the nation, the commitment by Entergy to reduce utility emissions by 50% below 2000 levels by 2030 and achieve net-zero emissions by 2050, requires a continued transformation of its generation portfolio. The IRP process evaluates available supply-side resource alternatives to meet customer energy needs in accordance with ELL's planning objectives of balancing reliability, affordability, and environmental stewardship, including the existing generation fleet, DSM programs, and supply-side resources. As part of this process, the Generation Technology Assessment was prepared to identify a range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ELL's planning objectives.

Technology Evaluation and Selection - As illustrated in Figure 24, ELL conducted an evaluation of the cost-effectiveness and feasibility of deployment for more than 30 potential supply-side resources. The three-phased (i.e., Technical, Economic, Technology Selection) process to select generation alternatives, consider qualitative and quantitative criteria, and results in a final selection of supply-side resources that are best positioned to meet customer energy needs in accordance with ELL’s planning objectives.

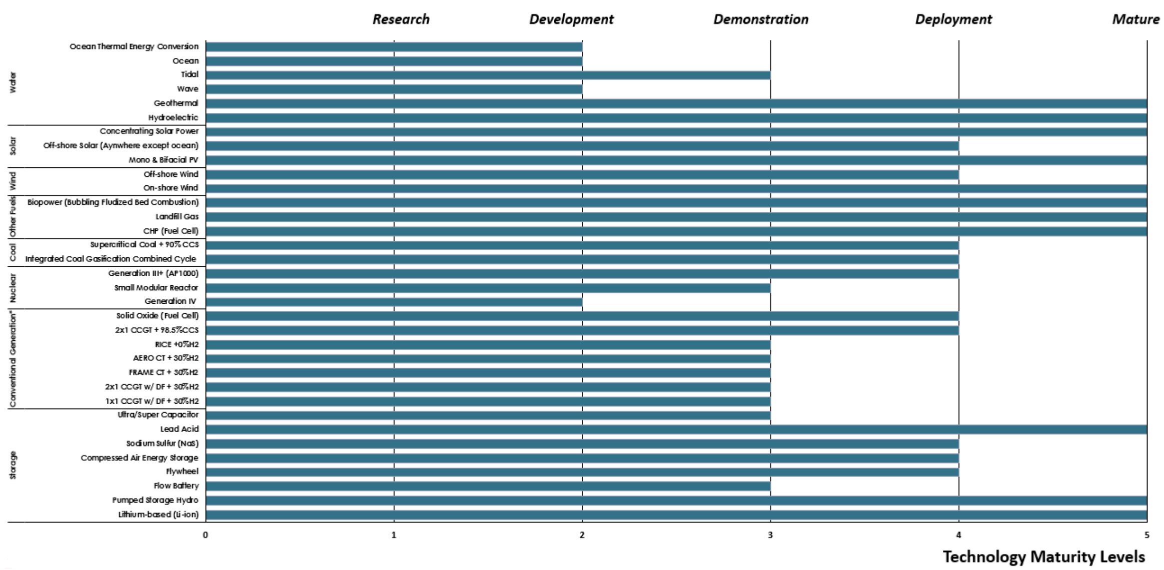
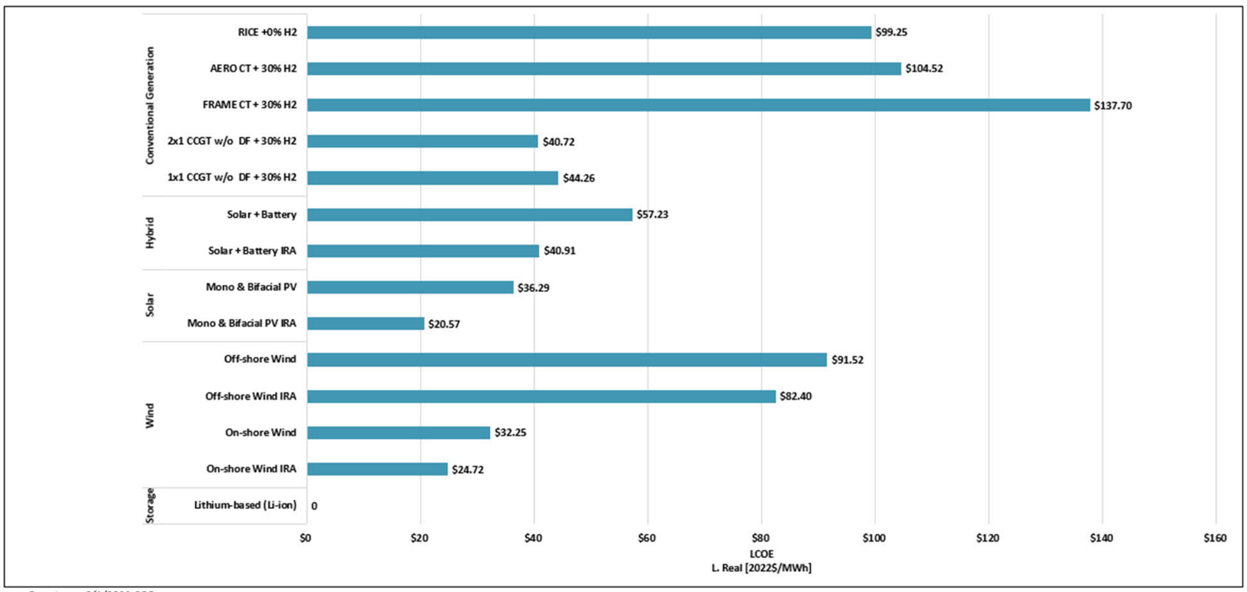


Figure 24: Technology Maturity Level

In the technical evaluation, potential supply-side resources were evaluated relative to technology maturity, environmental impact, fuel availability, and feasibility of deployment to serve ELL's service area. In the economic evaluation, ELL developed and compared technology alternatives relative to Levelized Cost of Electricity ("LCOE") and key performance indicators, including multiple renewable, energy storage, and hydrogen-capable conventional generation, as well as consideration for off-system solar and wind resources. Following the economic screening, the supply-side resources selected for inclusion in the capacity expansion models are those deemed to be the most feasible to serve ELL's generation needs based on comparative LCOE and performance parameters, deployment risks (cost/schedule certainty), and emerging commercial, technical, and policy trends. Notwithstanding the technologies specifically discussed in this IRP and included in the capacity expansion models, ELL continually evaluates existing, new, and emerging technologies to inform deployment decisions and building a balanced generation portfolio that optimizes its planning objectives. Figure *25* illustrates the LCOE results for the supply-side alternative selected for inclusion in the capacity expansion models.



- *Based on a 6/1/2023 COD resource.*
- *LCOE is calculated as levelized total cost over the book life divided by the levelized energy output over the book life.*
- *LCOE for storage is not shown because as storage just moves MWh from one time to another there is no actual 'output' of energy therefore it's undefined.*
- *Solar resources include an additional $55M per 100MWs for interconnection costs.*
- *Offshore wind values do not include cost adders for transmission.*
- *Inflation Reduction Act ("IRA")*

Figure 25:Levelized Cost of Electricity of Selected Technologies

In the sections that follow, the selected technologies are discussed in more detail as well as the key emerging supply trends and implications that will shape the future of ELL's resource portfolio.

Conventional Generation w/ Hydrogen Capability - Natural gas-powered generation technologies are a competitive supply-side resource alternative due to historically relatively lower natural gas prices in ELL's service area and suitability to serve a variety of supply roles (baseload, load-following, limited peaking). These technologies offer synergies with the existing ELL fleet, including supply chain economies of scale and deep-rooted operational expertise.

The long-term suitability of dual fuel natural gas and hydrogen powered generation technologies to meet ELL's planning and sustainability objectives is largely dependent on natural gas prices and technology improvements, specifically, development of hydrogen co-firing capabilities, from 30% co-blending today to approaching 100% hydrogen. For wider deployment of this technology, necessary advancements that need to be made, include, but are not limited to, building hydrogen production and delivery infrastructure, combustor systems, and emission reduction technologies for Nitrogen Oxide ("NO_x"). As Original Equipment Manufacturers ("OEMs") make advancements, ELL continues to track the development of hydrogen fueled power generation technology.

Table 11 below summarizes the natural gas-powered w/hydrogen capability generation alternatives resource assumptions, followed by a comparison of relative benefits of each alternative along with a description of each technology.

Table 11: Conventional generation with H2 capable-powered resource assumptions[24]

Technology	**Net Max Summer Capacity** [MW-ac]	**Installed Capital Cost** [2022$/KW]	**Fixed O&M** [2022$/KW]	**Variable O&M** [2022$/MWh]	**Full HHV Summer Heat Rate**[25] [Btu/kWh]	**H2** (%)
CT *(*M501JAC*)*	365	$925	$6.66	$14.74	9,165	30%
CCGT *(1x1* M501JAC*)*[26] w/o Duct Firing	525	$1,156	$18.43	$3.47	6,375	30%
CCGT *(2x1,* M501JAC*)*[27] w/o Duct Firing	1,055	$894	$12.07	$3.48	6,355	30%
Aero-CT *(* LMS100PA*)*	100	$1,438	$6.47	$3.21	9,015	30%
RICE *(*7x Wartsila 18V50SG*)*	129	$1,688	$23.35	$8.06	8,464	0%

Combined Cycle Gas Turbines (CCGT) with 30% Hydrogen Firing Capability - Driven by economies of scale and historically relatively low gas prices, CCGT fleet operators have remained competitive, from a $/MWh perspective, when compared to solar and wind resources. CCGTs are suitable to efficiently serve as baseload, load-following, and offer plant flexibility. In this analysis, CCGT units included are comprised of either one or two frame Combustion Turbines (CT) and a steam turbine that recovers thermal energy from the CTs, which provides an efficient heat rate

[24] Natural gas-powered resources shown are hydrogen capable, except for RICE resources. Assumptions do not include costs associated with firing hydrogen.

[25] Heat Rate in Full HHV Summer Condition. CCGT heat rate is reflective of the base capacity without duct firing.

[26] CCGT units without duct firing.

[27] Ibid.

and moderate flexibility. Achieving greater volumes for hydrogen co-firing will be dependent on the technology development of hydrogen fired CTs. Depending on the relative hydrogen co-firing volume, system modifications would be required in the CT and steam system of the plant. In addition to advancements in CT technology, potential modifications for a future hydrogen fueled CCGT plant could include, but is not limited to, modifications to the heat recovery steam generator system and post-combustion NO_x control systems.[28]

Frame Combustion Turbine (CT) with 30% Hydrogen Firing Capability - Historically, CTs have functioned as the technology of choice to support peaking application, resulting from consistent technological improvements, supported by relatively lower natural gas prices. Over time, renewable resources, particularly solar, have become an economically competitive source of peaking capacity to mitigate summer season reliability risk. While renewable resources are expected to play a larger share of the role for peaking applications, CTs can support integrating renewables and build a balanced, reliable, portfolio by offering quick-start (~30 minutes) backup power when renewables cannot meet peak demands.

Most dry, low-NO_x designs can accommodate hydrogen blends in the range of 20%-30% with advanced dry, low-NO_x technologies under development to enable higher blend rates up to 100% hydrogen fired systems.[29] Achieving higher hydrogen firing rates will be dependent on combustor designs as well as other system modifications, for example, fuel management systems/compression, CT enclosures, and control system updates.

Aeroderivative Combustion Turbine (AERO CT) with 30% Hydrogen Firing Capability - AERO CTs have gained market share in applications to serve peak and intermittent power, offering inherent flexibility as a product of applications from the aviation to power industry. Traditionally, AERO CTs provide higher flexibility than frame CTs due to their hot start time (10 minute), minimum up/down time (5/5 minute), and ramp rate (100 MW/minute).

AERO CT OEMs are continuing to develop combustion systems to enable higher hydrogen blend rates. Current dry, low-NO_x systems utilized within AERO CTs enable blending of hydrogen in the range of 30% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.

Reciprocating Internal Combustion Engine (RICE) with 0% Hydrogen Firing Capability - As renewable penetration increases, RICE units may be leveraged to support the integration of renewable generation. RICE units can support increased demand for reliability through dispatchable power that can be placed online rapidly with the ability to frequently start/stop in response to changing load conditions. RICE units can ramp up to a full load in less than 5 minutes and operate at about 33% of nominal rating without compromising heat rate, a unique capability versus CTs, which generally ramp at a slightly slower rate (10 – 15 minutes), and while they can turn down to approximately 40% of their rated output, heat rate is compromised. RICE units,

[28] Dr. Jeffrey Goldmeer, *Gas Turbines: Hydrogen Capability and Experience,* The Department of Energy (March 9, 2020), *available at* https://www.hydrogen.energy.gov/pdfs/06-Goldmeer-Hydrogen%20Gas%20Turbines.pdf

[29] Electric Power Research Institute Innovation Scouts, *Hydrogen-Capable Gas Turbines for Deep Decarbonization,* Electric Power Research Institute (November 14, 2019), *available at* https://www.epri.com/research/products/000000003002017544

however, tend to have higher actual forced outage rate versus expected forced outage rate, but as more units are deployed more broadly, this factor is likely to improve.

RICE OEMs have claimed that existing models are able to accompany blends of hydrogen up to 25%, however, they have yet to demonstrate this in the field. Technology advancements and the necessary plant modifications required to increase the hydrogen blend capability above 25% remains uncertain.[30] RICE OEMs are also working to develop models compatible with other potential low-carbon fuels.

Renewable and Energy Storage Systems - Over the past decade, driven by technology improvements resulting in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed around the world, particularly utility-scale solar, followed by onshore wind and battery energy storage systems ("BESS"). Renewable energy resources add fuel diversity and play a core role in building a balanced resource portfolio.

Renewable energy resources add fuel diversity and will play a core role in building a balanced and diverse resource portfolio, and when paired, renewable energy projects and energy storage technologies have zero net emissions. Due to the intermittent nature of renewable generation, a balanced portfolio must maintain the ability to meet the changing instantaneous nature of customer usage and renewable production curves (e.g., on-peak production versus off-peak production).

The IRP total relevant supply cost analysis incorporates key renewable energy provisions included in the Inflation Reduction Act (IRA) of 2022, which was signed into law in August 2022. The IRA includes tax credits for clean energy technology, with the goal of reducing carbon emissions. The tax credits include full production tax credits (PTCs) of $27.50/MWh (real 2022$) for solar, offshore wind, onshore wind and hybrid solar and assume the PTCs are realized at 90% through the cash conversion or monetization process permitted in the IRA. The analysis includes investment tax credits at 30% for standalone and hybrid battery resources, which are applied to 90% of total resource cost. Consistent with the IRA provisions, the tax credits are phased out over the IRP evaluation period, beginning in 2036. In addition to incorporating key IRA provisions, the IRP analysis incorporates an update to the solar technology interconnection cost, following through on the interactive IRP stakeholder engagement process to review solar interconnection costs. For solar resources, the IRP total relevant supply cost analysis reflects an incremental $55/kW capital cost to account for incremental transmission interconnection costs. This represents a reduction to the previous $100/kW capital cost adder included in the Draft IRP analysis.

Table 12 below summarizes the renewable and energy storage resource assumptions used in this IRP followed by a discussion on each technology.

[30] Wartsila, *Energy Solutions,* Wartsila (2021), *available at* https://www.wartsila.com/docs/default-source/power-plants-documents/pps-catalogue.pdf

Table 12: Renewable and Energy Storage Resource Assumptions[31]

Technology[32]	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2022$/KW]	Fixed O&M [2022$/KW-yr.]	Capacity Factor [%]	Useful Life [yr.]
Utility-scale Solar[33] (Single-axis tracking)	100	$1,063	$10.52	26.75% (MISO South)	30
Onshore Wind	200	$1,505	$37.72	36.8% (MISO South)	30
Offshore Wind	600	$3,620	$76.95	38.3% (Gulf of Mexico)	25
BESS[34] (Li-ion, 4hr)	50MW/ 200MWh	$1,171	$13.39	N/A	20
Solar + BESS	100 MW Solar 50 MW/ 200 MWh Battery	$1,612	$10.52	25.6%	30-year Solar 20-year Battery

Solar - Across the U.S., deployment of solar energy resources has continued to grow rapidly and as its economics improved, and solar has become a central resource in building a balanced portfolio. From 2014 to 2020, utility-scale solar capital costs declined by more than 50%, resulting from declines in global PV module prices and economies of scale from larger project capacities. While the cost for solar has recently increased due to several factors, resource alternatives have also increased in cost and PTCs for solar have helped to offset some of this increase. Therefore, despite the near-term market issues, solar remains an economic addition to ELL's portfolio and ELL's point of view remains that beyond 2030, project costs are expected to continue to decline, albeit at a slower pace than in the prior decade as the industry continues to mature. In addition to cost impacts from the industry maturing, new module designs and configurations continue to be developed to improve efficiency and reduce overall costs. Over the next 30 years, costs are expected to decrease with solar resources expected to become a larger share of the generation portfolio mix. However, because solar energy production is variable in nature, grid flexibility and quick start backup generation are necessary to ensure reliability. Additionally, as part of the

[31] Source: IHS 2020: All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

[32] Solar, wind, and BESS fixed O&M excludes property tax and insurance. Solar includes inverter replacement in year 16.

[33] Solar capacity value is representative of year 1. Further explanation of solar capacity value as evaluated in the 2021 ELL IRP is summarized in the "Portfolio Design Analytics" section.

[34] BESS round-trip efficiency is assumed as 86%. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by replacement of 10% of battery modules every five years (year 6, 11, & 16) to allow for a 20-year life.

planning considerations for utility-scale facilities, land size requirements and site-specific needs must be evaluated.

Onshore Wind - Onshore wind resources have gained momentum in the US and international markets, driven by technology improvements that reduced capital costs. Between 2014 to 2020, capital costs decreased by approximately 18%, resulting primarily from reductions in turbine costs due to economies of scale created from larger turbines with higher capacity projects. Further cost reductions are expected to be incremental as developers improve efficiency and as larger turbine model market penetration increases. Larger wind turbine blade diameters have rapidly entered the market, and while in 2010, no onshore wind project utilized blades 115 meter or larger, as of 2020, 91% met or exceeded that length.[35] ELL is considering the reliability, cost, and executability tradeoffs between the potential deployment of onshore and offshore wind resources located in its service area and imported from neighboring markets.

ELL is actively evaluating cost effective ways to integrate wind resources into its portfolio. However, some aspects of wind energy that is local to the area served by ELL is currently challenging compared to wind energy that serves some nearby regions. For example, wind energy in MISO South has an estimated capacity factor of ~37%, compared to those in MISO North (~47%) and SPP (~49%). However, ELL's wind resource options may include some local wind, and wind energy imports from nearby regions with a stronger wind resource.

Offshore Wind - In the U.S., the offshore wind industry has been developing with its first commercial offshore wind farm becoming operational in Rhode Island in 2016 (30 MW Block Island Wind Farm). At this time, while most of the U.S. industry is concentrated in the northeastern United States, potential projects have been developing across the U.S. with more widespread maturity having been achieved in Europe. Offshore wind technologies are comprised of both fixed and floating foundations, and in recent years, turbine capacity has increased significantly with OEMs offering larger diameter systems in the range of 14 MW per turbine. In 2022, the U.S. Bureau of Ocean Energy Management identified potential wind energy areas and proposed to hold the first federal lease auction in the Gulf of Mexico. Since ELL's service area is prone to frequent hurricanes, development of offshore wind resources in the Gulf of Mexico will depend, in part, on advancing the capability of wind energy generation equipment to withstand sustained hurricane force winds. Assuming technology improvements are achieved, conditions in the Gulf of Mexico and current economics, however, position fixed turbines are more suitable for deployment, particularly in areas with relatively shallower depths. Additional development of offshore wind projects in the northeast may positively impact costs, but for offshore wind resources in the Gulf of Mexico to be included in the longer- term transmission and supply planning efforts, technology improvements suited for ELL service areas along with reduction in resource cost projections, relative to alternative, will need to show a positive impact for its key stakeholders.

[35] Berkeley Lab, *Land-Based Wind Market Report,* U.S. Department of Energy (2022), *available at* https://emp.lbl.gov/wind-technologies-market-report/

An important advancement in the development of offshore wind in the Gulf of Mexico is an action laid out in Louisiana's Climate Action Plan that includes a goal of adding 5 gigawatts of offshore wind generation by 2035. Further, the LPSC has asked utilities to evaluate the costs and benefits of offshore wind in order to ensure every available technology is analyzed in long term resource planning initiatives. To advance this opportunity, in September 2022, ELL announced a Memorandum of Understanding ("MOU") with Diamond Offshore Wind regarding the evaluation and potential early development of wind power generation in the Gulf of Mexico. The MOU provides the framework toward future development of potential demonstration projects and in the near term will focus on the evaluation of grid interconnection to determine the optimal size and locations of future projects. This will be ELL's first step in understanding feasibility of projects. As part of this work, ELL will grow internal knowledge and build partnerships with external experts to understand costs in order to fully undertake a cost benefit analysis. In March 2023, ELL announced an MOU with RWE, AG which also seeks to explore such development opportunities in the Gulf of Mexico.

Battery Energy Storage Systems (BESS) - From 2015 to 2020, utility-scale BESS capital cost declined by 180% with battery modules contributing to two-thirds of the decline (ATB NREL), a trend that is expected to continue. Current use cases of battery technology are applied to discharge times that are four-hours or less to provide peak shaving capabilities. When strategically and efficiently integrated into the electric grid, BESS have the potential to provide transmission and distribution grid benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak shaving applications, BESS can provide voltage support, which mitigates the effects of electrical anomalies and disturbances. If paired together, BESS have the potential to deliver solar energy production into late afternoon hours, mitigating the ramping requirement created by the daily decline in solar energy production.

In addition to the above, BESS have the potential to offer additional values through MISO markets to benefit customers by effectively enabling an intra-day temporal shift between energy production and energy use. Through this process, energy can be absorbed and stored during off-peak/low-cost hours and discharged during on-peak/high-cost hours. When dispatched advantageously, the spread (i.e., cost difference) between the time periods can create cost savings for customers. BESS qualify in some markets for various ancillary service applications such as frequency regulation, reserves, voltage regulation, and given enough discharge duration, can qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including fire prevention.

Hydrogen - ELL is well-positioned to play a key role in the opportunities presented by hydrogen technology due to the Company's proximity to the existing US hydrogen infrastructure. Low-to zero-carbon hydrogen appears to represent one of the key technology evolutions that can potentially support continued transformation of ELL's resource portfolio. Hydrogen has the potential to provide diverse reliability and sustainability benefits through its applications as a dual fuel paired with natural gas and providing long duration energy storage. It also provides a potential pathway to ensure that highly flexible, load following power generation resources with the capability for spinning reserves have a line of sight into operations. Hydrogen investments by customers in or near ELL's territory, recently accelerated by the tax credits provided in the Inflation Reduction Act, support this value proposition. While hydrogen remains one of several emerging technologies the Company is monitoring as an option for meeting resource needs, it appears to have the potential to play an important role in a balanced resource portfolio.

Carbon capture, utilization, and sequestration - ELL is monitoring the development of carbon capture, utilization, and sequestration ("CCUS") technology for potential deployment for its existing and future fleet to support resource planning objectives. CCUS can potentially serve as a decarbonization solution in ELL's existing natural gas fleet and as a complement to its low-to zero-carbon hydrogen strategy for traditional hydrogen production using steam methane reforming. The geology and infrastructure in south Louisiana are well-suited to deployment of CCUS technology and support incurring reduce costs associated with CO_2 transportation and storage. ELL's proposal that was submitted to the United States Department of Energy (DOE) for the purpose of obtaining a financial assistance to support integrating a full-scale CCS facility at the Lake Charles Power Station was recently selected for negotiation of a financial assistance award.

Newer generation of fossil fueled technologies coupled with carbon capture and storage may present the opportunity to generate cost-effective low to zero carbon electricity in the future. The Company will continue to monitor the development of this technology.

Advanced Nuclear Technology and Small Modular Reactors - Nuclear energy is a key component for meeting ELL's long-term resource planning objectives. As ELL continues to operate its existing nuclear fleet, it continues to observe industry developments in Advanced Nuclear Technology and Small Modular Reactors (SMRs) to meet customer needs. SMRs may potentially offer several benefits, including being physically smaller, reduced capital investments and opportunities for incremental power additions, as well as supplying base load electricity including system "inertia" that is lacking in inverter-based resources. In addition, SMRs generally rely on passive safety systems, requiring no manual intervention or externally applied forces to safely shut down. Pairing SMRs with renewable resources would provide complementary technology that does not depend on climate and time of day. The Company will continue to monitor the development of this technology.

Summary of Emerging Supply Trends and Implications - Advancement in generation technologies provides new opportunities to meet customer needs reliably and affordably, increasingly rendering new supply-side generation alternatives as viable options to address planning objectives. ELL's planning processes strive to understand these technological changes to enable the Company to design a portfolio of resources and services that meet customers' needs and wants, while maintaining a reliable grid.

Renewable and energy storage system technologies have emerged as viable economic alternatives and are expected to continue to improve through the planning horizon. Increased deployment of intermittent generation will need to be balanced with flexible, dispatchable and diverse supply alternatives. Smaller, more modular resources, such as Aero-CT, RICE, and battery storage, provide an opportunity to reduce risk and better address locational, site-specific reliability requirements while continuing to support overall grid reliability. Combining these trends provides additional opportunities to meet ELL's planning objectives.

Looking ahead, ELL will endeavor to maximize clean energy options while balancing reliability, affordability, and environmental stewardship. Efforts will include renewable energy as well as modern resources with optionality to be powered with hydrogen and/or retrofitted with carbon capture and sequestration technology.

DSM Potential Resource Assessment

As part of the development of ELL's 2023 IRP, ELL engaged a third-party consultant, ICF International, Inc., ("ICF") to conduct an independent forecast of the achievable potential of EE and DR program types and DER technologies on the utility's system. EE and DR programs and DER technologies were selected for analysis based on their relevance to utility planning practices nationwide and their specific relevance to ELL's customers and planning processes.

The resulting ICF forecast was used by ELL to provide hourly inputs for its IRP modeling process over the period 2023 through 2042. ICF produced forecasts for two scenarios: high levels of program or technology adoption and reference levels of adoption.

The starting point of ICF's forecasts for ELL was the selection of relevant EE and DR programs and DER technologies. Among EE, ICF analyzed existing programs offered through Entergy Louisiana's Quick Start EE programs as well as additional measures that ICF determined could be cost-effective to deploy for ELL customers. Among DR, ICF analyzed event-based program types, separated for residential, commercial, industrial, and agricultural customers, as well as existing and new rate-based DR programs. For DER, PV and battery storage technologies were separated by residential and C&I adoption.

For each selected EE program, DR program and DER technology, ICF produced hourly ELL net load forecasts covering 20 years for each of two scenarios: reference (expected) adoption and high adoption. The reference scenario reflects ICF's judgment as to the level of adoption that is most likely to occur given ELL and external market information available at the time of the study.

As described in detail later in this IRP, the incremental EE portfolios were included in Aurora's Capacity Expansion Tool for economic selection along with supply-side resource options for Futures 2 and 3. The DR programs were evaluated based on each program's benefit to cost ratio where DR with ratio higher than 1 were selected. Each portfolio included an assumed start date, program measure life, hourly demand profile, and annual program costs.

Environmental

Another key driver to changes in future resource needs is the various environmental regulations that have the potential to affect the long-term viability of ELL's existing generating units. Five key areas of regulations are discussed here: Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals Rule, Effluent Limitation Guideline Rule, and Potential Greenhouse Gas Regulation. The uncertainty associated with each area varies. For example, the Regional Haze requirements have been in place for some time and are far more developed, with greater certainty as to the compliance requirements and timing. Even so, the specifics that will be required for compliance with Regional Haze are not known fully at this time.

Regional Haze Rule - The current Regional Haze Program was established as part of the 1990 amendments to the Clean Air Act. This program is designed to protect visibility at certain federally designated Class I areas and to return visibility conditions at those areas to natural background visibility conditions by the year 2064. This is to be accomplished via a series of 10-year planning periods where each state is charged with surveying contributions from air emissions sources in that state and developing a Regional Haze State Implementation Plan ("SIP") to ensure that sufficient emission reductions occur during each planning period to remain on course to achieve natural background conditions in all Class I areas by 2064. During each planning period, the State of Louisiana must evaluate contributions from sources within the state for potential impacts to visibility conditions at various Class I areas. During the first planning period, Louisiana finalized a SIP which imposed a lower emission limitation, corresponding to the use of lower-sulfur coal, for emissions of sulfur dioxide (SO_2) from Nelson Unit 6. This limit went into effect in January 2021 and the Unit has operated in compliance with this regional haze SIP limit since this time. Compliance is achieved via management of the sulfur content of the fuel supply to the unit.

For all states, a SIP for the regional haze second planning period, which spans from 2018 to 2028, was to be submitted to the EPA by July 31, 2021. Many states, including Louisiana, continue to prepare their second planning period SIP for submittal to the EPA. On July 8, 2021, the EPA issued a memorandum to provide states with additional information and feedback to consider for supporting their SIP development. In that same memorandum, EPA recognizes that while some states have already submitted final SIPs, others are at different stages of the SIP development process. Subsequently, in April of 2022, the EPA announced that it would issue a formal Finding of Failure to Submit to any state which did not submit a final SIP for the Regional Haze second planning period by August 15, 2022.

As part of their SIP development process for the second planning period, the Louisiana Department of Environmental Quality (LDEQ) issued Information Collection Requests (ICRs) to ELL which requested that certain air pollution control retrofit analyses be conducted for emissions of SO_2 and oxides of nitrogen (NO_x) from Unit 6 and emissions of NO_x from Units 4 and 5 at the Ninemile Point Station.

LDEQ issued a draft regional haze SIP for public review and comment in April of 2021, and this draft SIP did not propose to require any additional pollution control requirements for any ELL units. LDEQ received significant public comment on this draft SIP and continues to work towards the development of a final SIP. As a result, the state did not meet the August 15, 2022, deadline for submittal of a final SIP and EPA formally published a Finding of Failure to Submit for Louisiana on August 30, 2022. This finding will be effective on September 29, 2022 and triggers an obligation for EPA to either approve a final SIP submitted by Louisiana or to issue a final Federal Implementation Plan (FIP) for Louisiana within two years, by September 28, 2024.

Final determinations of whether any additional air pollution control retrofits are necessary at ELL generating units will be made once EPA either approves a SIP or issues a final FIP for Louisiana. This is expected to occur in 2023 or 2024.

Cross-State Air Pollution Rule (CSAPR) - The EPA finalized the CSAPR in 2011 under the “good neighbor” provision of the Clean Air Act to reduce transported pollution that significantly affects downwind non-attainment and maintenance interference for the 2008 ozone National Ambient Air Quality Standard (“NAAQS”). The rule was vacated and stayed December 30, 2011, but in late 2014 the stay was lifted following a Supreme Court reversal of the lower court decision. Louisiana is subject to CSAPR for ozone-season (May 1 – September 30) emissions of NO_x. Affected entities must hold one allowance for every ton of NO_X and SO_2 generated, depending on the programs in which their respective state is required to participate.

Phase I of CSAPR went into effect in May 2015 and Phase II went into effect in May of 2017. On September 7, 2016, the EPA issued a CSAPR update rule which revised the CSAPR program. This 2016 update rule revised the total allowance pool for Louisiana sources.

In March of 2021, the EPA issued the revised CSAPR update rule, which was published in the Federal Register on April 30, 2021. This rule establishes a new CSAPR Group 3 which is comprised of 12 of the 21 CSAPR Group 2 states. Louisiana was one of the 12 states moved to CSAPR Group 3 and the state-wide CSAPR NOx allowance budget for Louisiana was reduced by approximately 20% by this 2021 rule. Due to the more limited number of NOx emission allowances budgeted to states subject to the Group 3 program, allowance costs increased for Group 3 allowances from historical values of $100-500 per allowance under the Group 3 program to approximately $6,000 per allowance by February 2022.

On April 6, 2022, the EPA issued a new regulatory proposal to again revise the CSAPR to move additional states to the Group 3 allowance program and to further reduce state NOx emission budgets for Louisiana and 23 other states, including Arkansas, Mississippi, and Texas. These further revisions to the CSAPR program were proposed in order to address interstate transport requirements of the Clean Air Act with respect to the 2015 National Ambient Air Quality Standard (“NAAQS”) for ozone. Under the April 2022 proposal, the statewide NOx emission allowance budget for Louisiana with a further decrease of approximately 37% (from the 2022 budget) in 2023 and a cumulative decrease of approximately 75% (from the 2022 budget) in 2026. EPA proposed to establish the stringent 2026 state budget via a proposed dynamic budgeting approach to be conducted in 2025, based on prior-year actual unit operating and emissions data and presumed pollution control retrofits to install Selective Catalytic Reduction (SCR) NOx emission control systems on most coal-fired and certain large gas-fired generating units prior to the 2026 ozone season.

ELL-owned (or co-owned) units identified by EPA for such SCR retrofits, under this proposal included: Nelson 6, Big Cajun II Unit 3, Little Gypsy 2, Little Gypsy 3, Ninemile 4, and Ninemile 5. While the EPA proposal would not have explicitly required SCR retrofits for any units, it would significantly reduce state NOx emission budgets and corresponding unit-level emission allocations as if these SCR retrofits had occurred, resulting in a likely significant NOx emission allowance shortfall, in the 2026 and subsequent ozone seasons, for any unit which continues to operate but does not conduct a SCR retrofit or otherwise significantly reduce NOx emissions.

In February 2023, EPA finalized disapproval of the Louisiana Interstate Transport SIP for the 2015 ozone NAAQS. EPA subsequently finalized revisions to the CSAPR program, in the form of a Federal Implementation Plan (FIP) in March 2023 with initial changes going into effect for the 2023 ozone season. With respect to Louisiana, EPA's final rule was substantially similar to the April 2022 proposal, with a few key changes. These key changes in the final rule include: delaying full implementation of the budget reduction proposed for 2026 until 2027, with half of this reduction occurring in 2026 and the remainder in 2027, creation of a "pre-set" minimum state NOx budget for 2026-2029, and raising the limit for the maximum number of program-wide allowances that can be "banked" and carried forward for use in future ozone seasons.

There are ongoing legal challenges to EPA's disapproval of the Louisiana Interstate Transport SIP, including challenges by the Louisiana Attorney General and Louisiana Department of Environmental Quality, Louisiana industry groups, as well as a challenge by ELL. The SIP Disapproval in Louisiana has been stayed by the U.S. Fifth Circuit Court of Appeals pending review. A decision on the merits of the Louisiana SIP Disapproval by the Fifth Circuit will be made at a later, undetermined date. There may also be legal challenges to the FIP following the official publication thereof. The framework EPA used to determine where the rule would apply and what the new emission allowance budgets would be may survive those challenges. So long as the stay of the Louisiana SIP disapproval remains in effect, the FIP and associated changes to the CSAPR program will not go into effect in Louisiana and ELL's generation units will continue to receive NOx allowance allocations under the higher Louisiana state NOx budget established by the 2021 version of the CSAPR Group 3 program.

Since EPA's proposed FIP was issued in April 2022, significant price volatility has been reported for Group 3 NOx emission allowances. Reported pricing for Group 3 allowance transactions increased from approximately $6,000/allowance prior to the EPA proposal to the range of $15,000 to $47,000 per allowance during the third and fourth quarters of 2022. Group 3 NOx allowance pricing has been in the range of $10,000-$14,000 per allowance since EPA's final revisions were released in March 2023. While the stay granted by the Fifth Circuit appears likely to delay implementation of the final CSAPR FIP in Louisiana, Louisiana remains in the Group 3 CSAPR trading program and ELL will be impacted by these higher Group 3 allowance prices in the event that it becomes necessary to procure additional NOx emission allowances.

Coal Combustion Residuals Rule - ELL operates a coal ash landfill which is regulated as a Coal Combustion Residuals ("CCR") unit at Nelson Unit 6, which is subject to the CCR rule. In April 2015, the EPA published the final CCR rule regulating coal ash from coal-fired generating units as non-hazardous wastes under RCRA Subtitle D. The final regulations became effective on October 19, 2015, and created new compliance requirements for CCR management including modified storage, new notification and reporting practices, product disposal considerations, ongoing monitoring requirements and CCR unit closure criteria. In December 2016, the Water Infrastructure Improvements for the Nation Act ("WIIN Act") was signed into law, which authorizes the EPA to enforce the CCR rule rather than leaving primary enforcement to citizen suit actions.

On August 21, 2018, the D.C. Circuit Court vacated and remanded several provisions of the CCR rule that relate to inactive and unlined surface impoundments. On August 28, 2020, the EPA issued a final rule with a revised date of April 11, 2021, that unlined surface impoundments and units that failed the aquifer location restriction must cease receiving waste and initiate closure.

The Nelson 6 facility operates a coal ash landfill which is regulated under the CCR rule. The Nelson 6 facility does not operate any surface impoundments regulated by the CCR rule.

The CCR rule allows states to seek approval from EPA for state CCR permit programs. Louisiana is working toward submission of a state CCR permit program for EPA approval but has not completed development of this program.

Effluent Limitation Guideline Rule - Updates to the Effluent Limitation Guideline rule ("ELG") were finalized by the EPA on November 3, 2015. These revisions apply to ELL's coal-fired generating asset, Nelson 6, and require that coal-fired electric generating units achieve zero discharge of bottom ash transport water (BATW). The requirement was originally scheduled to become effective between November 1, 2018, and December 31, 2023, with the exact date to be determined by the permitting authority (LDEQ). On September 17, 2017, the EPA finalized a revision to the ELG rule which modified the earliest possible compliance date from November 1, 2018, to November 1, 2020. In this action, the EPA also indicated its intent to reconsider other aspects of the 2015 ELG rule, including the requirements for bottom ash transport water. On October 13, 2020, EPA issued a further revision to the final rule which would allow for limited discharges of bottom ash transport purge water under certain defined circumstances.

The Nelson 6 unit utilizes a dry ash handling system to manage fly ash generated by operation of the unit. However, the site utilizes a wet sluicing system to manage bottom ash. This system utilizes BATW and may generate a BATW discharge under certain circumstances. ELL has obtained a modified and renewed Louisiana Pollutant Discharge Elimination System (LPDES) permit from the LDEQ which allows for such limited discharges of BATW in accordance with the provisions of the October 2020 revisions to the ELG rule.

In March 2023, EPA released proposed revisions to the ELG rule which would require that coal-fired generating units achieve zero discharge of BATW by no later than December 31, 2029. ELL tracks the progress of this proposed revision to the ELG and advocates for flexible implementation of any revisions.

316(b) Cooling Water Intake Rule - Section 316(b) of the Clean Water Act requires the EPA to issue regulations on the design and operation of water intake structures to minimize adverse impacts on aquatic organisms. On August 15, 2014, the EPA issued the final 316(b) rule for existing electric generating facilities which use one or more cooling water intake structures to withdraw water from waters of the US and have a cumulative design intake flow of greater than 2 million gallons per day (MGD).

Implementation of the 316(b) rule is ongoing at ELL's generating facilities, with technology evaluations expected to occur at the Ninemile Point and Waterford 2 generating stations in 2025-

2026, and at the Little Gypsy generating station in 2027-2028. The results of these technology evaluations will inform the selection of appropriate water intake technology to install at each facility to reduce the impingement and entrainment of aquatic organisms in the water intake at each site.

Potential GHG Regulation - ELL's Point of View ("POV") is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon control program are highly uncertain.

Under both the Obama and Trump administrations, EPA developed regulations for emissions of greenhouse gas (GHG) emissions from existing electric generating units ("EGUs") under Section 111(d) of the Clean Air Act. The Clean Power Plan ("CPP") was developed by the Obama Administration and the Affordable Clean Energy ("ACE") rule was developed by the Trump Administration. Both rules were stayed, vacated, and/or remanded by federal courts and neither was fully implemented.

EPA's authority to regulate GHG emissions from existing EGUs was again reviewed by the US Supreme Court in 2022, and in June 2022 the court issued a decision in *West Virginia v EPA* which held that that Section 111(d) of the Clean Air Act ("CAA") does not provide EPA with the authority to establish GHG emission standards based primarily upon generation shifting from coal to natural gas-fired generating units. The court held that such generation shifting would constitute a "major question" that is, an agency action that would result in "…vast economic and political significance." For such a "major question," the court held that EPA would require clear authorization from the U.S. Congress providing the regulatory authority asserted by the agency, and that Section 111(d) of the CAA does not provide the authority cited by EPA to justify the use of generation shifting to craft the CPP.

On May 11, 2023, EPA released a new regulatory proposal to regulate GHG emissions from EGUs. This proposal includes both proposed emission guidelines for GHG emissions from existing fossil fuel-fired EGUs, including both coal- and gas-fired EGUs, as well as proposed revised GHG emission standards for new gas-fired combustion turbine EGUs. At this time, this proposal has not yet been published in the Federal Register. This proposal will be subject to public review and comment, and EPA is expected to issue a final rule in 2024.

ELL is currently reviewing this new regulatory proposal from EPA and will consider the impacts of the final rule in future IRPs.

CO_2 Price Forecasts - ELL's CO_2 point of view is based on the following four cases:

- A "No CO_2 Policy/Clean Energy" in which, the power sector does not face a CO_2 price due to preference for clean energy standards, lack of federal action, or other factors.
- A "Regulatory" in which, Low prices representative of action under Clean Air Act (similar to Clean Power Plan) are utilized.
- A "50% Reduction" in which, Mid prices representative of price needed to reach national target of 50% reduction from 2020 levels by 2050 are utilized.

- A “Legislative” in which, High prices consistent with Climate Leadership Council proposal and other proposals from the 116th Congress are utilized.

After deriving projections of CO_2 allowance prices for each of these four cases, the following probability weightings were applied to each to arrive at the ELL's point of view assumption:

Table 13: CO_2 Probability Weightings

Reference CO_2 Case Probability	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2035**	**2040**	**2045**
No CO_2 Policy/ Clean Energy	100%	90%	70%	60%	55%	50%	45%	40%	35%	30%	20%	10%
Regulatory	0%	10%	20%	25%	27%	29%	31%	33%	35%	30%	25%	20%
50% Reduction	0%	0%	10%	15%	18%	21%	24%	27%	30%	35%	40%	45%
Legislative	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	15%	25%

The low case assumes no CO_2 price, the reference case assumes the ELL's point of view CO_2 price, and the high case assumes the CO_2 Price High Tax case as shown below:

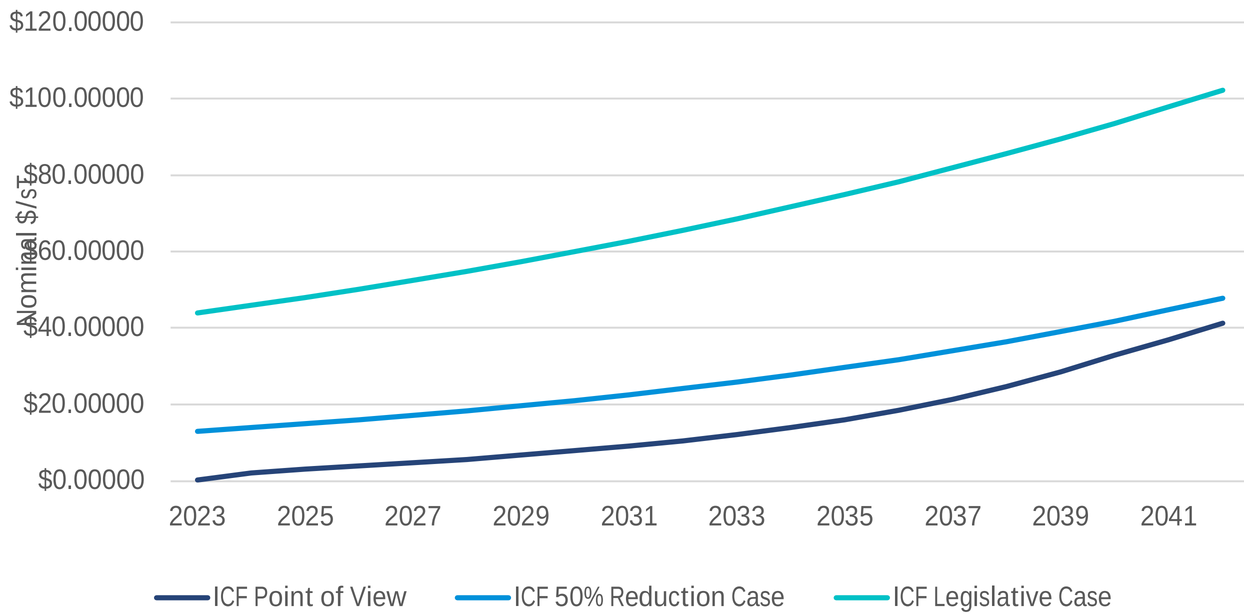


Figure 26: CO_2 Price Forecast Scenarios

Fuel Price Forecasts

Natural Gas Price Forecasts - Three natural gas price forecasts were used in the development of the 2023 IRP. The near-term portion (year one) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of November 2021. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point of view regarding future natural gas prices utilizes a consensus across several independent, third-party consultant forecasts. Gas markets are influenced by a number of complex forces; consequently, long-term natural gas prices are highly uncertain and become increasingly uncertain as the time horizon increases. Therefore, ELL presents and uses three alternatives for natural gas prices to address this uncertainty. In levelized 2023 dollars per MMBtu throughout the IRP period, the reference case natural gas price forecast is $3.73, the low case is $2.92, and the high case is $5.00.

Described in more detail later in this section, each of the IRP Futures assumes the natural gas price forecast sensitivity appropriate for the future world envisioned.

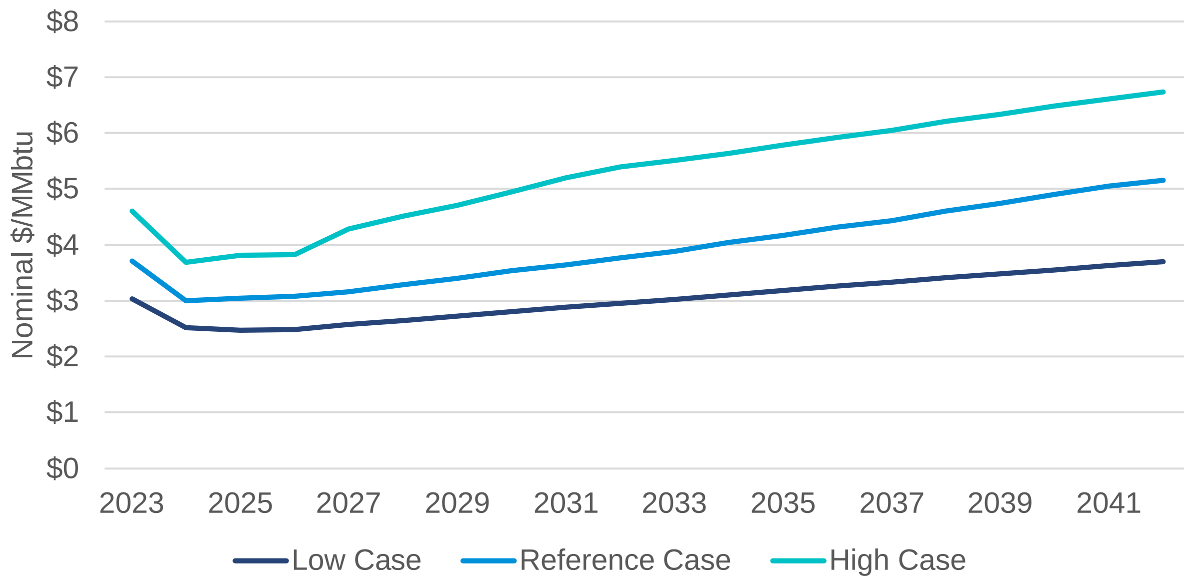


Figure 27: Annual Natural Gas Price Forecast

Coal Price Forecasts - The delivered to plant coal price forecast for Nelson 6 is based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. The current transportation rate for Nelson 6 is escalated by 2% annually and current fuel surcharges are escalated by the On-Highway Diesel fuel price index. Current plant specific delivery component costs are escalated based on an appropriate index to forecast the future year component cost. In levelized 2023 dollars per MMBtu throughout the IRP period, the delivered coal price for Nelson 6 is $2.06. The delivered coal price forecast for non-Entergy plants comes directly from the Aurora default input database provided by Energy Exemplar and prices vary by plant.

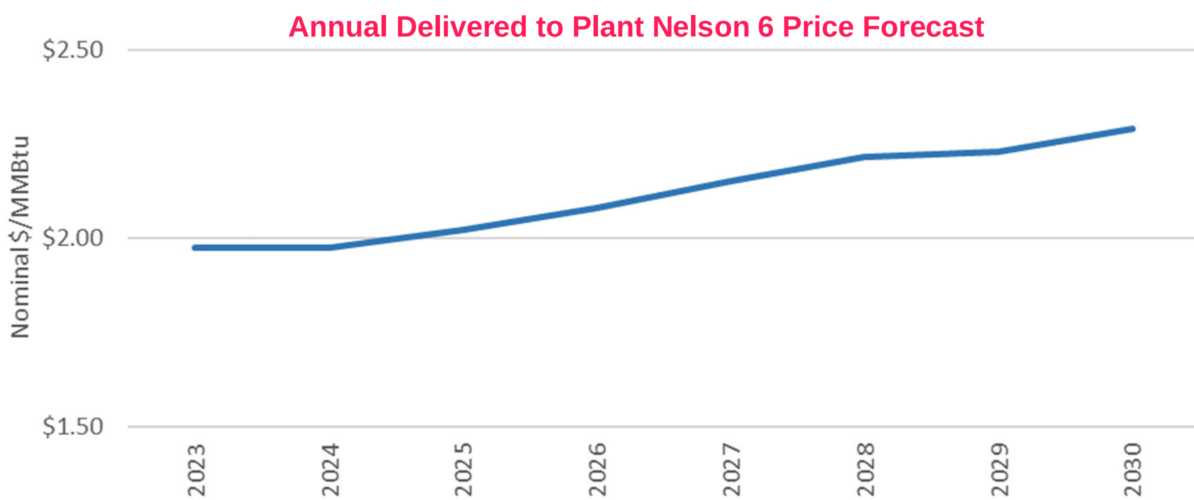


Figure 28: Coal Price Forecast

Chapter 5 Modeling Framework

Summary

- As with the 2019 IRP, a futures-based approach was employed for the 2023 IRP. Three futures were modeled to bookend a broad range of uncertainties.
- Renewable capacity accreditation was aligned with MISO MTEP methodology.
- Planning reserve margins and capacity accreditation were applied on an annual basis. Season requirements are being considered for modeling exercises going forward as discussed in the MISO Resource Adequacy ("RA") & Planning Reserve Requirements section in Chapter 3.

Futures-Based Approach

Instead of analyzing and planning for one set of outcomes, ELL's IRP uses a futures-based approach to evaluate portfolios across a broad range of potential future conditions. This is done because long-term outcomes are uncertain for many input assumptions. Futures are described as different combinations of assumptions that could plausibly coexist together resulting in a range of market outcomes. The 2023 IRP considers the following three Futures:

Table 14: IRP Futures Assumptions

	Future 1	**Future 2**	**Future 3**
Peak Load & Energy Growth	Reference	Highest	Between Reference and Highest
Natural Gas Prices	Reference	High	Low
MISO Coal Deactivations[36]	All ETR coal by 2030 All MISO coal aligns with MTEP Future 1 (46 year life)	All ETR coal by 2030 All MISO coal aligns with MTEP Future 3 (30 year life)	All ETR coal by 2030 All MISO coal aligns with MTEP Future 2 (36 year life)
MISO legacy gas deactivations	55 year life	45 year life	50 year life
Carbon tax scenario ICF 2020 post-election	ICF Point of View	ICF Legislative Case (High)	ICF 50% Reduction Case (Mid)
ITC/PTC Assumptions	Current Methodology[37]	HR 5376	Current Methodology
DSM Potential Study	ELL EE embedded in BP22 Load Forecast + for DR: option to select ICF up to High Case	Option to select ICF DR & EE up to High Case	Option to select ICF DR & EE up to High Case
Allow Future Emitting Resource	Yes	No	Yes

[36] Deactivation assumptions will be consistent with current planning assumptions for ELL owned or contracted generation.

[37] While Current Methodology was utilized in the capacity expansion model, following the Draft IRP Filing it was decided to include Inflation Reduction Act (IRA) tax credits assumptions for all futures. This update was completed outside of model and Capacity Expansion was not re-run.

Narrative	Aligns with Point of View CO_2 price consistent with expected probability weighted CO_2 price. Point of View CO_2 leads to electrification decisions driven by sustainability efforts rather than CO_2 prices. Point of View CO_2 leads to relatively constant consumption of natural Gas and constant pricing. Coal is not economic to operate past 46 years of life and Legacy Gas is not economic to operate to full life assumption.	Aligns with high CO_2 price consistent with aggressive decarbonization mandate scenarios. High CO_2 price increases natural gas extraction and export leading to high gas prices. Coal is not economic to operate past 30 years of life and Legacy Gas is not economic to operate to full life assumption.	Aligns with mid CO_2 price representative consistent with ICF 50% Reduction Case Mid price CO_2 lowers consumption of Natural Gas thus decreasing prices on a global scale. Coal is not economic to operate past 36 years of life and Legacy Gas is not economic to operate to full life assumption

Renewables Capacity Credit - The solar capacity credit assumption used in the IRP aligns with the solar assumption detailed in the 2021 MISO Futures Report. Under this assumption, all solar units have a 50% capacity credit at the beginning of the study period and then decreases by 2% starting in year 2026, until the capacity credit reaches a minimum of 30%.

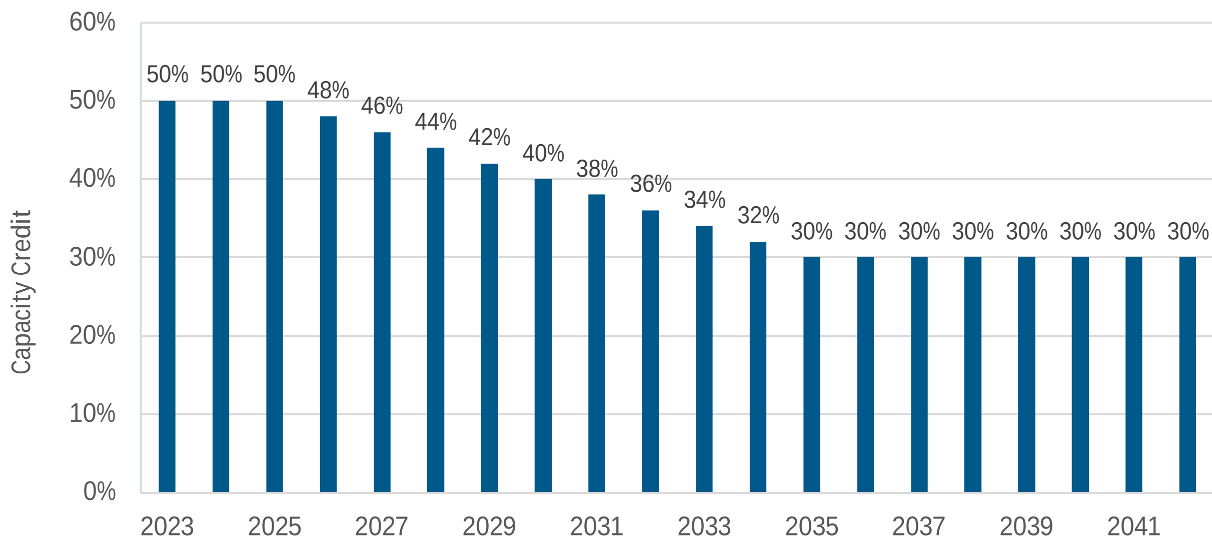


Figure 29: MTEP21 Solar Capacity Credit Approach

The 16.3% wind capacity credit assumption used in the IRP is sourced from MISO's 2021/2022 PY Wind & Solar Capacity Credit Report. The MISO system-wide wind capacity credit is calculated using a probabilistic approach to find the Effective Load Carrying Capability ("ELCC") value for all wind resources in the MISO footprint.

Market Modeling

The development of the 2023 IRP relied on the Aurora[38] Energy Market Model to develop optimized portfolios and generate Locational Marginal Prices ("LMPs") for the MISO energy market and for ELL under a range of possible futures. Aurora is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, available DSM program alternatives, environmental constraints, and future demand forecasts. Aurora's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints.

The first step within the market modeling process is to utilize Aurora to perform capacity expansion to develop a projection of the future market supply based on the specific characteristics of each future. Once the market supply resources are determined for each future, energy market simulations are performed, which results in hourly energy prices for each of the three futures. This projection encompasses the power market for the entire MISO footprint (excluding ELL). MISO (excluding ELL) projected power prices are extracted from the energy market simulations to assess potential portfolio strategies for ELL within each future. Figure 30 - Figure 35 below show the projected market supply for each of the three futures. Figure 36 represents projected annual MISO (excluding ELL) power prices for each future.

[38] The Aurora model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for ELL. Aurora supports a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publicly owned utilities, regulators, planning authorities, independent power producers and developers, research institutions, and electric industry consultants.

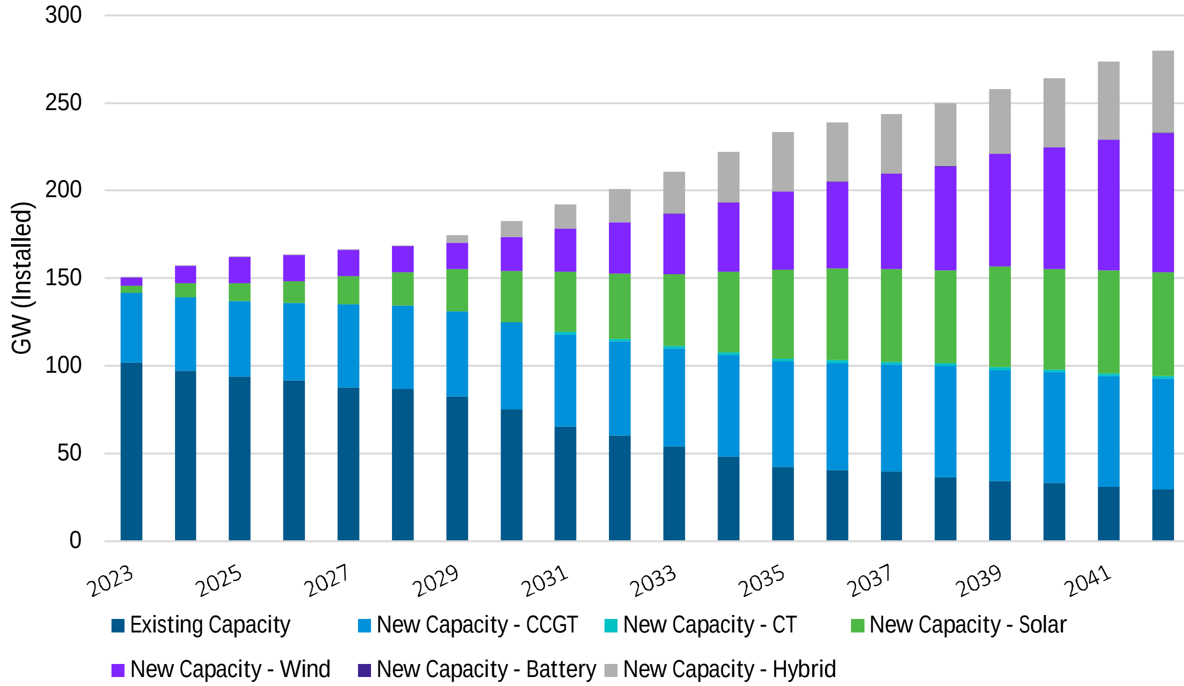


Figure 30: Future 1 Annual Projected Future MISO Market Non- ELL Installed Capacity

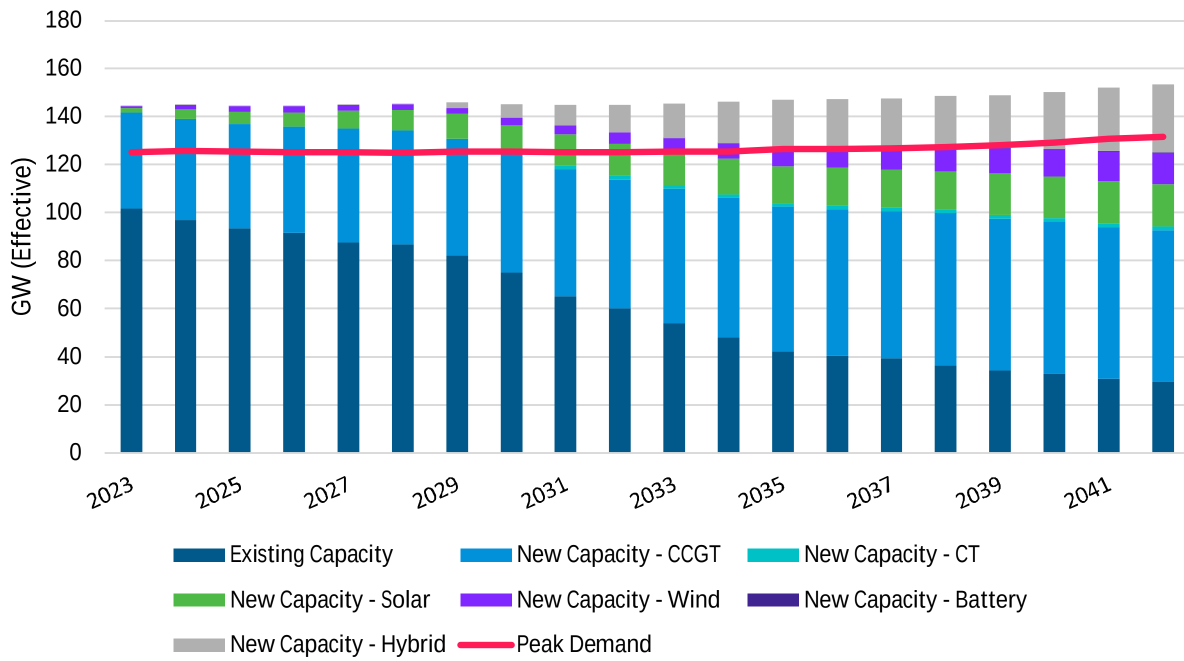


Figure 31: Future 1 Annual Projected Future MISO Market Non-ELL Effective Capacity

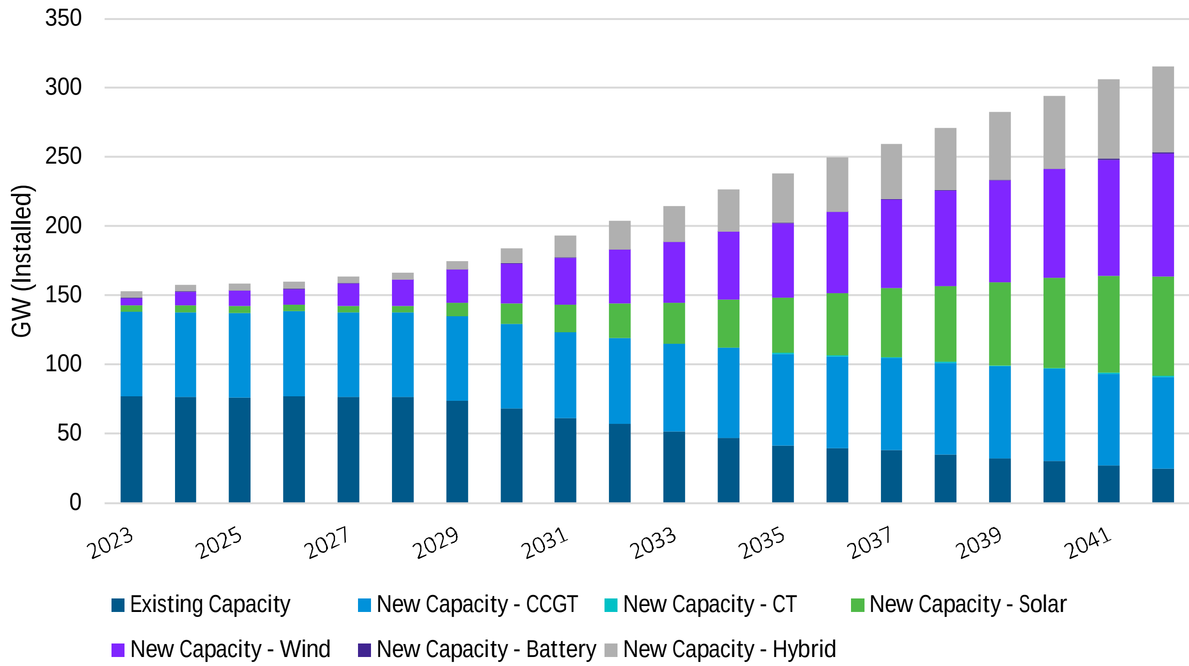


Figure 32: Future 2 Annual Projected Future MISO Market Non- ELL Installed Capacity

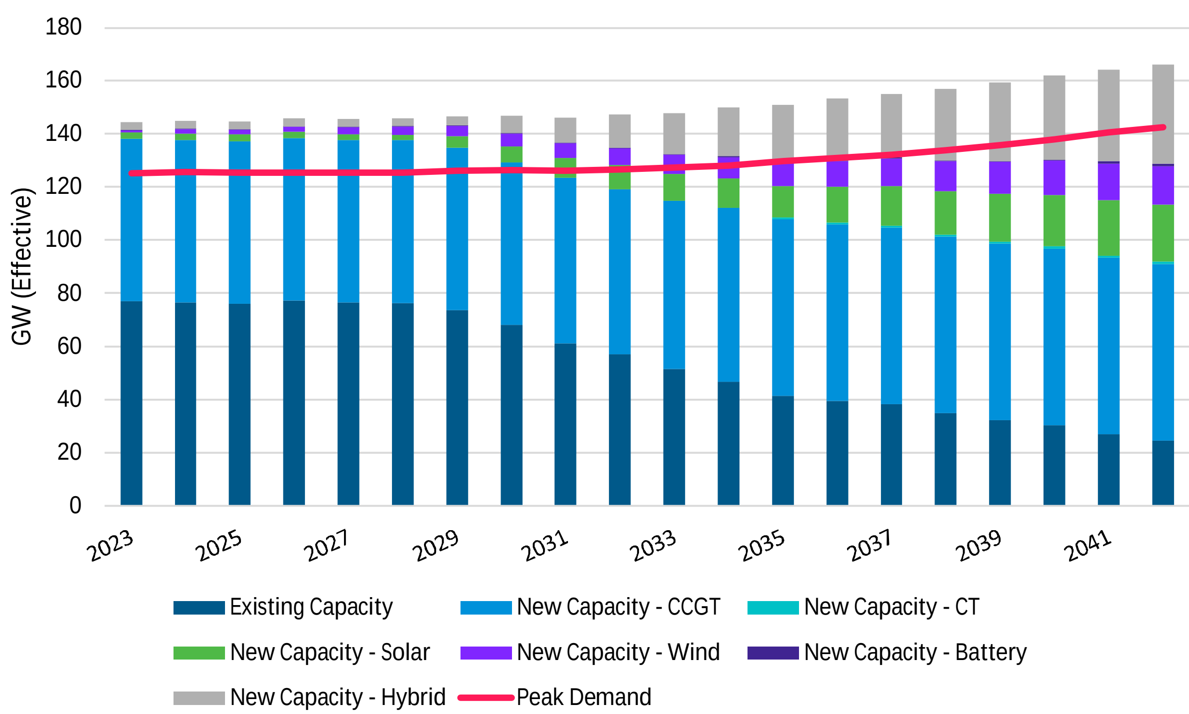


Figure 33: Future 2 Annual Projected Future MISO Market Non-ELL Effective Capacity

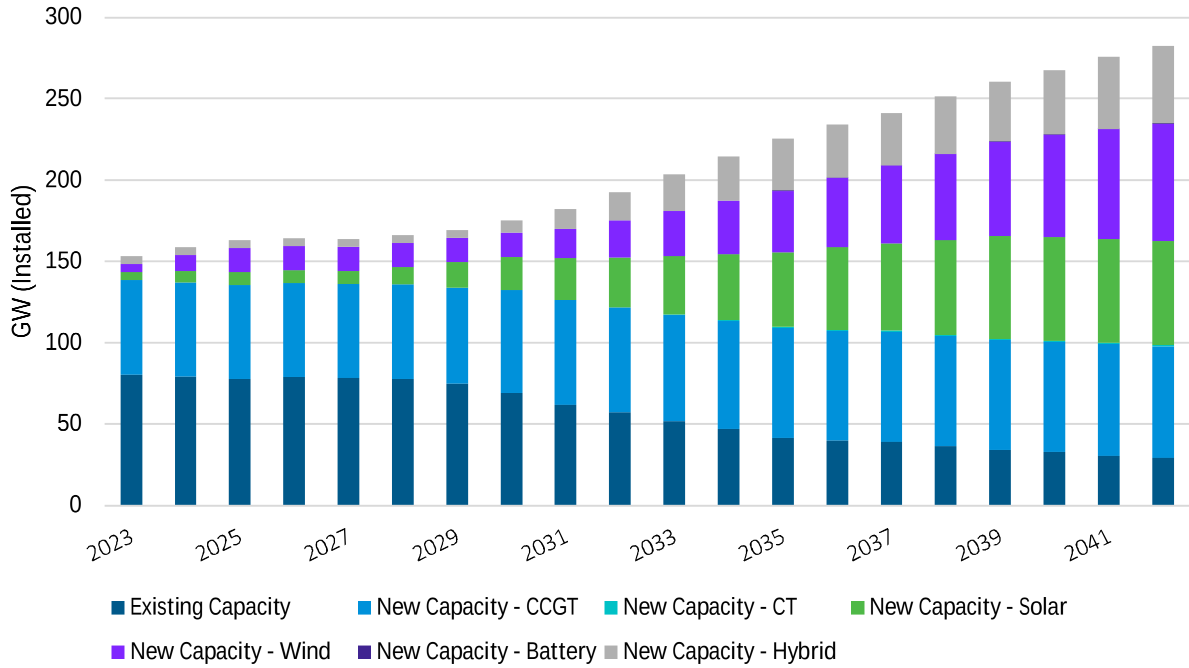


Figure 34: Future 3 Annual Projected Future MISO Market Non- ELL Installed Capacity

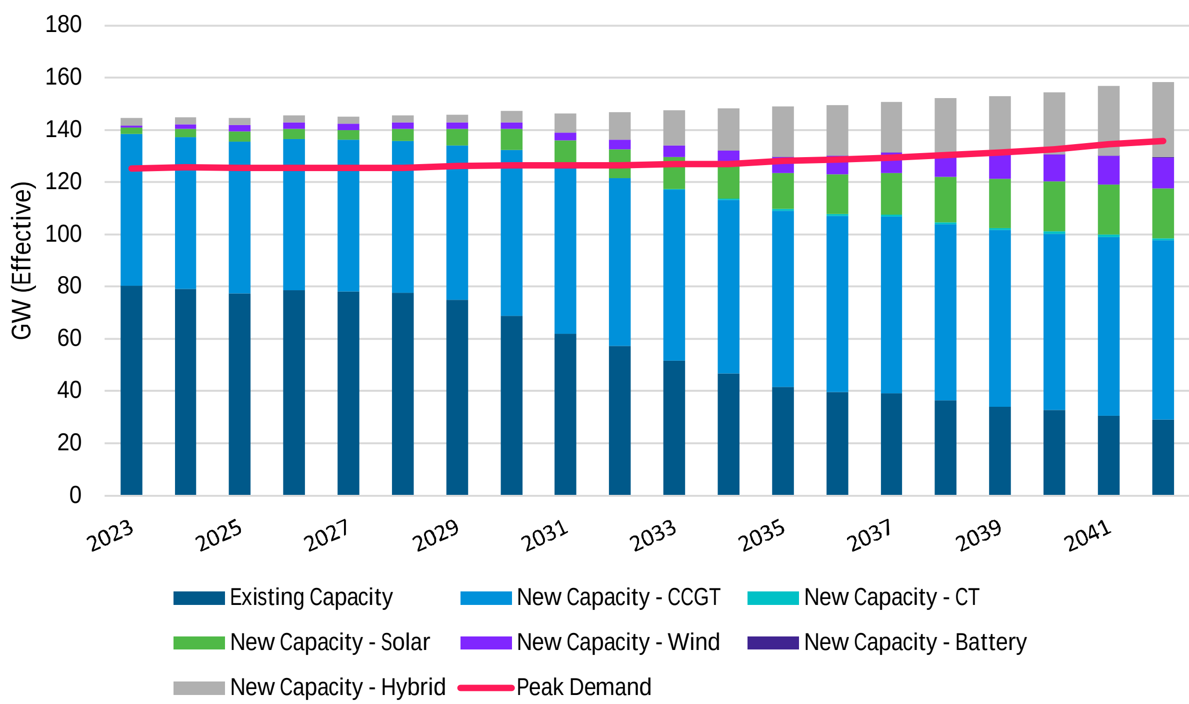


Figure 35: Future 3 Annual Projected Future MISO Market Non-ELL Effective Capacity

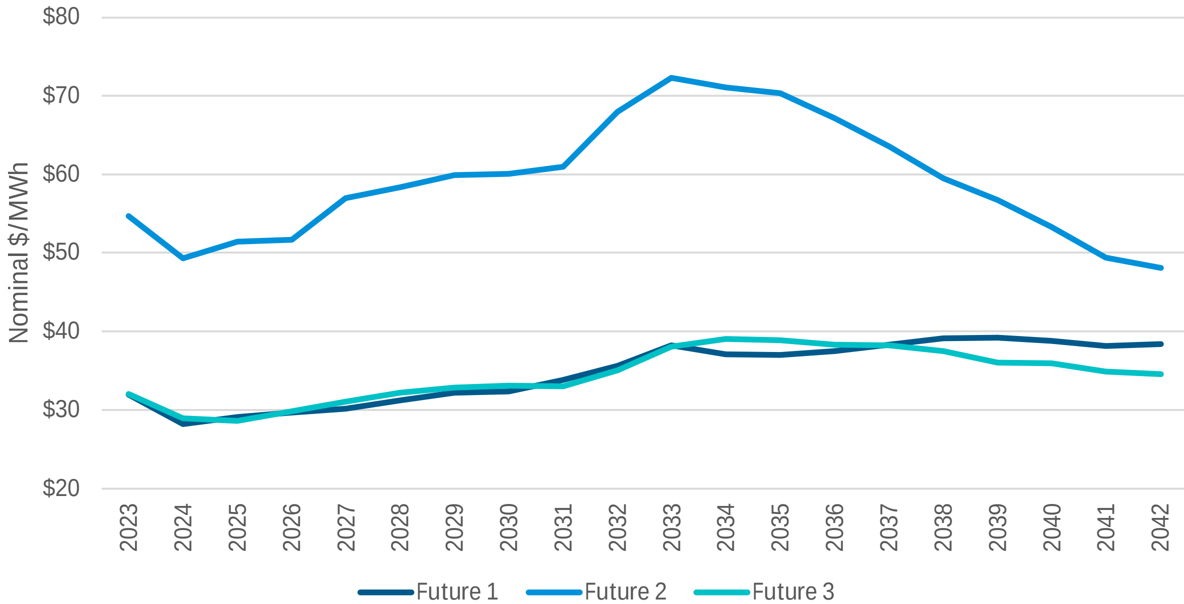


Figure 36: Average Annual MISO Market Non-ELL LMP

ELL Portfolio Optimization

Following the market modeling process, which results in LMPs for the non-ELL MISO region, the Aurora long-term capacity expansion logic was used to identify economic type, amount, and timing of demand-side resources and supply-side resources needed to meet ELL's future capacity needs. The result of this process is a portfolio of demand-side resources and supply-side resources that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the three futures (the "optimized portfolio").

DSM Modeling - DSM Potential Programs were evaluated as resource alternatives to identify the most economic programs to be included in ELL's portfolio. Potential DR and EE programs were developed and evaluated by ICF based on the characteristics and attributes described in Chapter 4. ICF's reference and high DR programs were evaluated using ELL and ICF data to estimate the net benefits of each program. DR programs with benefit to cost ratios higher than 1 were selected and used to reduce the peak load. Since the high and reference programs are mutually exclusive, only one tier of each program was allowed to be selected.

EE programs were selected using Aurora. In Future 1, no ICF EE programs were allowed since EE was already embedded in the base BP22 load forecast[39]. In Future 2 and Future 3 EE was not included in the load forecast, hence, both high and reference ICF EE programs were offered for economic selection. Similarly, since the high and reference programs are mutually exclusive, only one tier of each program was allowed to be selected.

[39] The amount of embedded EE within the BP22 load forecast included in Future 1 is similar to the ICF High EE scenario

Aurora considers the cost and revenue of energy and capacity in the context of the MISO market for each EE program alternative. Due to the nature of the forecasted EE programs that gain adoption by customers over time, each program was designed to start in 2023 and continue through the end of the technical life of the technology, if applicable, or through the end of planning horizon. Because ELL is not projected to have a need for incremental capacity in 2023, the selection of the EE programs in the model was based strictly on economics, and not capacity position. The capacity credit of selected EE programs is counted toward meeting ELL's capacity needs through reduction of peak load.

Table 15: High ICF DSM Programs Selected by Aurora by Future

ICF High DSM Programs	Type	Sector	Future 1	Future 2	Future 3
Agricultural	DR	Com	✓	✓	✓
DLC Water	DR	Com	×	×	×
Interruptible	DR	Com	✓	✓	✓
Smart Thermostat	DR	Com	✓	✓	✓
Interruptible Existing	DR	Ind	✓	✓	✓
Interruptible New	DR	Ind	✓	✓	✓
DLC Water	DR	Res	×	×	×
Smart Thermostat	DR	Res	✓	✓	✓
Agricultural	EE	Com	-	✓	✓
Large Commercial Solutions	EE	Com	-	✓	✓
Midstream Lighting	EE	Com	-	✓	✓
Retro-commissioning	EE	Com	-	✓	✓
Small Business Direct Install	EE	Com	-	✓	✓
Small Commercial Solutions	EE	Com	-	✓	✓
Industrial SEM	EE	Ind	-	✓	✓
Large Industrial Solutions	EE	Ind	-	✓	✓
AC Solutions	EE	Res	-	✓	✓
Appliance Recycling	EE	Res	-	✓	✓
Behavioral Home Energy	EE	Res	-	✓	✓
Home Performance	EE	Res	-	✓	✓
Income Qualified Solutions	EE	Res	-	✓	✓
Manufactured Homes	EE	Res	-	✓	✓
Midstream HVAC	EE	Res	-	✓	✓
Multifamily Solutions	EE	Res	-	✓	✓
Prepay	EE	Res	-	✓	✓
Retail Lighting	EE	Res	-	✓	✓
School Kits	EE	Res	-	✓	✓

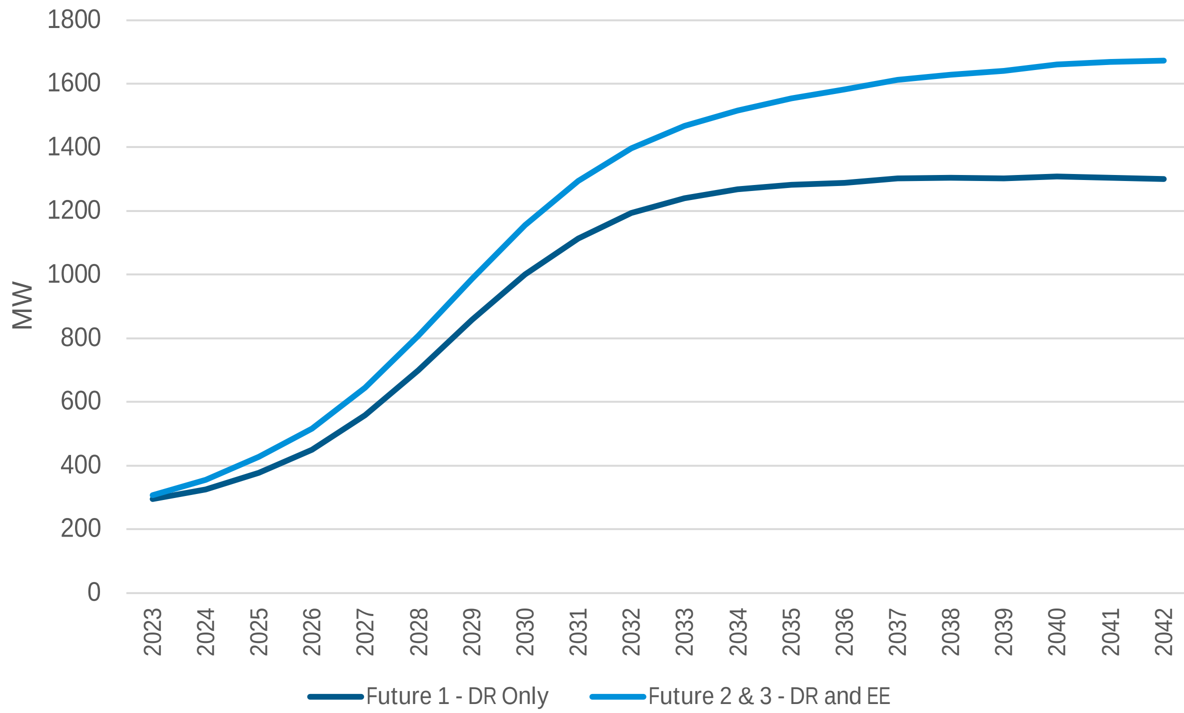


Figure 37: Selected Gross DR and EE Programs[40,41]

Results - Capacity Expansion & Total Relevant Supply Cost Metric

The following figures show the timing of incremental resource additions throughout the ELL IRP evaluation period of 2023-2042. All existing and planned capacity for ELL, as described in the Existing Resources section of Chapter 3, was included in the AURORA model to determine timing and need for incremental resources. These existing and planned resources, however, are not shown in the figures below. For each optimized portfolio, the load requirement is reflective of the future for which the portfolio is optimized (e.g., Portfolio 1 is optimized in Future 1), and includes the assumed effects of incremental DSM on the peak load requirement.

Each ELL portfolio is simulated with the Aurora production cost model for the relevant future and combined with other spreadsheet-based cost components to produce the total relevant supply cost. As previously noted, all three portfolios are consistent with and make progress towards Entergy Corporation's announced sustainability and emissions reductions goals. The results of the analysis are summarized below.

Portfolio 1

Future 1 is defined by reference load growth, reference gas price, high DR addition, and the ICF Point of View CO_2 price. The capacity under the reference assumptions is optimized to include a

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[40] Future 1 shows the DR Selected through the Capacity Expansion Evaluation. EE was embedded in the Load Forecast; therefore, EE is not included in the table, however, it was included in Future 1.

[41] DSM grossed up for reserve margin and transmission loss.

diverse mix of baseload energy producing resources, renewable energy projects, energy storage, and DSM.

In Portfolio 1, 1.6 GW of thermal capacity and 9.3 GW of renewable capacity were added within the 20-year planning horizon. The optimized Portfolio 1 also includes 450 MW of additional BESS capacity which could be paired with a renewable resource or utilized as standalone resources. Most of the ICF high DR programs were economic in Portfolio 1 and included to help reduce the peak load. In the optimized Portfolio 1, solar was added first to meet the capacity need from load growth and assumed existing unit deactivations, and then CCGTs were added when large legacy dispatchable gas units are assumed to deactivate. Solar was added until the daylight hour's energy demand became saturated and then wind was added as an economic compliment to serve the load in non-daylight hours. BESS was added near the end of the study period when it is needed to move intermittent renewable energy to hours of high customer demand net of renewable energy production. These resources and DR programs together address ELL's energy needs as well as account for the future deactivation of dispatchable units. More detail on the total relevant supply cost estimate and projected rate impacts for each future can be found in Appendix I.

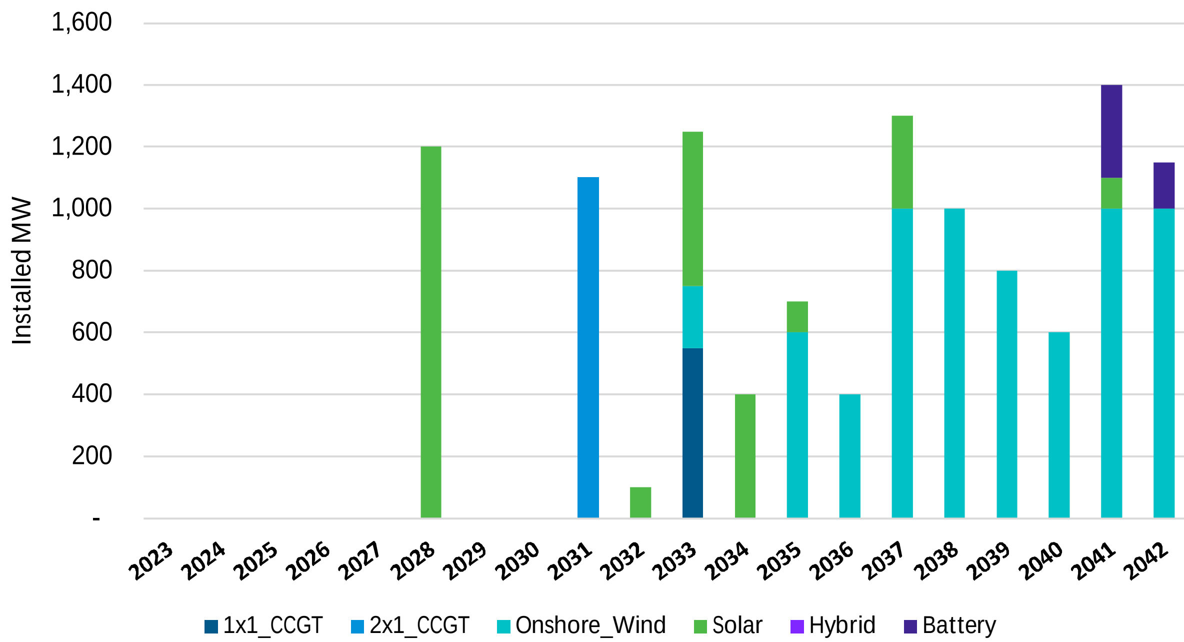

Figure 38: Annual Capacity Expansion Additions Portfolio 1

Table 16: Capacity Expansion Optimized Portfolio 1

Technology[42]	Portfolio 1 Installed MW (ICAP)	Portfolio 1 Effective MW (UCAP)
2x1 CCGT	1,102	1,102
1x1 CCGT	549	549
Aeroderivative CT	0	0
Single Axis Solar	2,700	810
Hybrid (Solar + Battery)	0	0
Lithium-Ion Battery	450	450
On-shore Wind	6,600	1,076
Total Supply Side Additions	11,401	3,987
Gross DR Programs (2042)[43]	1,301	1,301

Portfolio 2

Future 2 is defined by high load growth, high gas price, high DSM addition, and the ICF Legislative Case CO_2 price. Because Future 2 assumes an environment which would be favorable for the economics of renewable resources, emitting resource additions were not allowed to be built. Due to the high load and low peak credit of renewables, more incremental capacity was required in Portfolio 2 compared to Portfolio 1.

In Portfolio 2, 8.8 GW of installed capacity additions are sourced from solar resources and another 1.5 GW are sourced from solar resources with BESS. Portfolio 2 also includes 16 GW of additional wind resources. As shown in Table 15 above, most of the DR and all the EE offered in the ICF high programs were included resulting in 1,673 MW of gross DR and EE netted against the peak. Future 2 produced an environment where ELL would be reliant on wind resources and solar resources to meet the peak and energy requirements. Portfolio 2 also relies on the MISO energy market to a larger extent than portfolios 1 and 2 to balance ELL's generation and demand due to the level of intermittent resources added to ELL's portfolio. For the reasons described throughout this document, over-reliance on the MISO markets can pose risks to customers and reliability. Solar with BESS (i.e., hybrid resources) were added towards the end of the study to move intermittent renewable energy to hours of high customer demand net of renewable energy production.

[42] Reciprocating Internal Combustion Engine, Combustion Turbine, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[43] DSM value represented in Table 16 is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

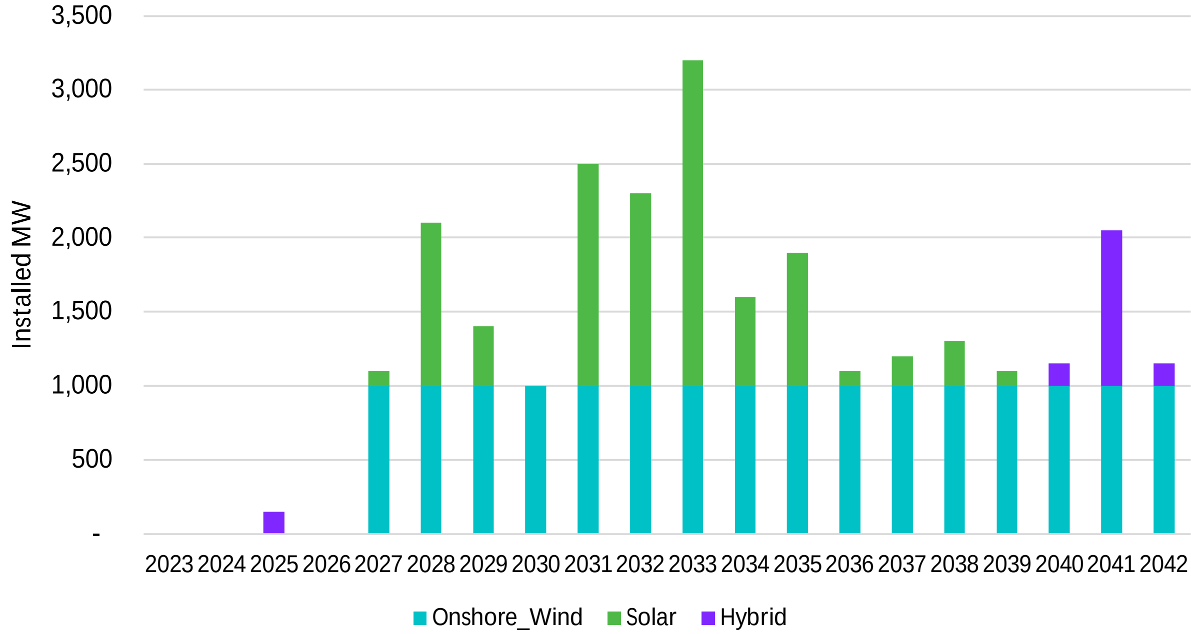

Figure 39: Annual Capacity Expansion Additions Portfolio 2

Table 17: Capacity Expansion Optimized Portfolio 2

Technology[44]	**Portfolio 2 Installed MW (ICAP)**	**Portfolio 2 Effective MW (UCAP)**
2x1 CCGT	-	-
1x1 CCGT	-	-
CT	-	-
Single Axis Solar	8,800	2,640
Hybrid	1,500	900
Lithium-Ion Battery	0	0
On-shore Wind	16,000	2,608
Total Supply Side Additions	26,300	6,148
Gross DR and EE Programs (2042)[45]	1,673	1,673

[44] Reciprocating Internal Combustion Engine, Aeroderivative CT, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[45] DSM value represented in Table 17is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

Portfolio 3

Future 3 is defined by load growth that is between reference and high, low gas price, high DSM addition, and the ICF 50% Reduction Case CO_2 price. Economically, this environment favors gas based dispatchable resources. The optimized capacity selected to best fit this environment includes a greater supply of gas resources with renewable energy, energy storage, and DSM resources providing a substantial amount of capacity.

In Portfolio 3, 3.2 GW of installed capacity additions are sourced from solar resources and another 450 MW are sourced from solar resources with BESS. The optimized Portfolio 3 also includes 400 MW of additional BESS capacity which could also be paired with a solar resource or utilized as standalone resources. Also, an additional 2.8 GW are sourced from combined cycle resources. Like Portfolio 2, most of the DR and all the EE offered in the ICF high programs were included, shown in Table 15 above, which resulted in 1,673 MW of gross DR and EE netted against the peak. First, solar was added for capacity and energy needs, and then CCGTs were added to when large legacy gas units are assumed to deactivate. Solar was added until the daylight hour's energy demand was saturated and then wind was added to serve the load in non-daylight hours. Finally, BESS was added near the end of the study to move intermittent renewable energy to hours of high customer demand net of renewable energy production.

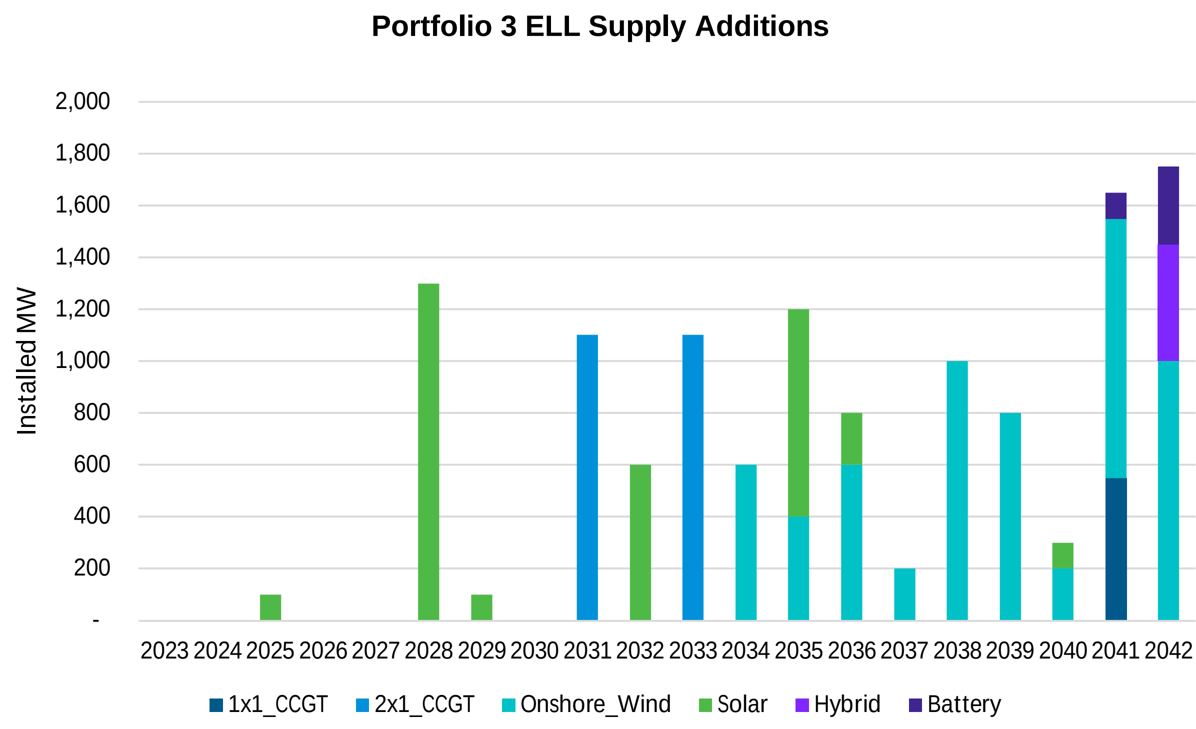

Figure 40:Annual Capacity Expansion Additions Portfolio 3

Table 18: Capacity Expansion Optimized Portfolio 3

Technology[46]	Portfolio 3 Installed MW (ICAP)	Portfolio 3 Effective MW (UCAP)
2x1 CCGT	2,204	2,204
1x1 CCGT	549	549
CT	-	-
Single Axis Solar	3,200	960
Hybrid	450	270
Lithium-Ion Battery	400	400
On-shore Wind	5,800	945
Total Supply Side Additions	12,603	5,328
Gross DR and EE Programs (2042)[47]	1,673	1,673

Qualitative Risk Characteristics

The results of the ELL IRP are not intended as static plans or pre-determined schedules for resource additions and deactivations. As ELL nears execution decisions regarding its resource portfolios, it will be important to understand the relative risk that contemplated portfolios may bring. The following factors are intended to give ELL an indication of the qualitative risk characteristics that may contribute to future portfolio decisions:

Market Factors - Reviewing market relative energy coverage within the MISO market metrics allows ELL to assess the level of exposure to market prices for a portfolio. A portfolio that is forecasted to generate less or more energy relative to their demand relies on the MISO energy market to make up its need, resulting in a higher energy price risk if LMPs are higher than anticipated, or higher fixed-cost risk if LMPs are lower than anticipated.

Reliability - Performing a reliability analysis provides ELL the ability to understand the relative reliability attributes of a portfolio for reasonably balancing regional requirements related to capacity, transmission, and reliability.

Economic, reliability, and risk evaluation - The analysis of total relevant supply cost, which represents the incremental fixed costs and total variable supply costs to serve customers' resource needs reliably under the assumptions of a particular Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the 3 optimized Portfolios in all three Futures. Information on the total relevant supply cost and risk analysis can be found in Appendix I.

[46] Reciprocating Internal Combustion Engine, Aeroderivative CT, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[47] DSM value represented in Table 23 is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

Modernization of Fleet - Understanding technology based useful life assumptions coupled with the average age of generating resources helps to inform an assessment of potential risks associated with maintaining and operating a portfolio of assets.

Executability - Assessing the executability of a portfolio allows ELL to evaluate the relative risks associated with the procurement of single or multiple resources within the timeframe needed. This assessment aims to highlight the potential time and cost risks associated with procuring a potential portfolio of resources such as: Interconnection/Deliverability, MISO queue process, RFP process and negotiations, construction, etc.

Optionality - Optionality considers the adaptability of a portfolio which enables ELL to adjust to various market conditions, such as how soon resources must be procured within the portfolio, the portfolio's capability to use hydrogen, or the portfolio's ability to adapt its supply role.

Fuel Supply Diversity - Fuel supply diversity assesses the level of exposure to fuel supply concerns, such as commodity constraints.

Environmental - Analyzing the relative CO_2 emissions impact of a portfolio allows ELL to understand the risks associated with changing laws, regulations, and environmental market pressures.

Chapter 6 Action Plan

Summary

- Increasing the amount of renewables capacity in ELL's portfolio is supported under a broad range of future conditions.
- The next driver for a large capacity deficit will be the timing of deactivation of legacy resources and load growth. Incremental additions of renewables continue to be a cost-effective approach to address that need.
- Potential may exist for incremental cost-effective demand response in ELL's portfolio.

Findings & Conclusions

As discussed above, the Aurora capacity expansion process resulted in three distinct resource portfolios, each of which is economically optimal for the combinations of assumptions for the respective future. Comparison across the futures provides insight on the supply additions that are robust under a wide range of uncertain future outcomes over the 20-year planning horizon.

Findings Across Futures - When reviewing the results of the resource portfolios across the futures, the many varying inputs across the futures must be taken into consideration. The portfolios that are developed based on this broad range of uncertainties reflected in the IRP Futures may provide insight into the types of resources that can be cost effective over this range of possible outcomes; however, caution must be taken when comparing results between the futures. Table 19 below summarizes key results for each future:

Table 19: Modeling Results Summary

2023-42 Modeling Results (MW)	Portfolio 1	Portfolio 2	Portfolio 3
Total Incremental Installed Capacity:	12,640	27,973	14,158
Natural Gas Capacity Additions:	1,580	0	2,635
Renewable Capacity Additions:	9,300	25,800	9,300
Battery Capacity Additions:	450	500	550
DSM Capacity Additions:	1,310	1,673	1,673

Renewable Resources are Even More Cost-effective than was Shown in ELL's Prior IRP - Renewables account for the majority of incremental supply additions across all three of the futures. In comparison to the 2019 IRP, incremental gas-powered capacity additions have decreased significantly. Table 20 below shows the proportion that renewable additions make of the future portfolios. These percentages ranged from 13% to 57% in the 2019 IRP. By contrast, dispatchable gas-powered and BESS resource additions are primarily made to provide flexible capacity to allow integration of solar and wind resource additions, though the amount and timing varies across futures because of different market conditions and amount of renewable resources added.

This result supports the conclusion that adding renewables to ELL's portfolio is a cost-effective approach across a broad range of future assumptions. This means that the Company is well poised to take actions that further the sustainability goals of its customers and of Entergy Corporation while still following the principles of least-cost resource planning.

Table 20: Renewable Capacity Additions (%)

Future	Renewable[48] resource capacity additions as percent of total incremental supply additions
Portfolio 1	74%
Portfolio 2	92%
Portfolio 3	66%

DSM is Cost-effective in all Futures - A significant amount of DSM (EE and DR) programs are cost-effective and included in the results for all three futures. The amount selected varies from a somewhat lower level in Future 1 of 1,310 MW of capacity contribution to the highest level in Futures 2 and 3 of 1,673 MW of capacity contribution by 2042. This result indicates that opportunity may exist for ELL to explore growth of existing or potentially new, cost-effective DSM programs as part of its future portfolio of resources. In addition to being an alternative to supply side generation, DSM resources may also address unique customer preferences, as well as reliability needs.[49]

Timing of First Addition - Excluding the planned resources where procurement efforts are already underway and/or the LPSC has already approved the additions,[50] the year in which the first incremental resource addition is needed to meet the reserve margin target is 2028 for Future 1, and 2025 for Futures 2 and 3. Futures 1 and 3 assume lower load growth than Future 2. Therefore, a 2025 supply need may result should higher load growth occur or the timing of legacy resource deactivations occur earlier than assumed or both. Given the uncertainty around both of these drivers, a plan to continue methodically adding generation between 2025 and 2029 is needed.

[48] Renewable resources include solar, solar with storage, wind, and BESS technologies.

[49] ELL notes that in the on-going rulemaking related to administration of DSM programs (Docket No. R-31106), Staff issued new draft rules on March 7, 2022. Among other things, these draft rules (if implemented as drafted) would radically change the paradigm for administration of DSM programs by removing control of the programs from utilities and seeking to hire a statewide third-party administrator to oversee programs for all utilities. It is unclear whether this model will be implemented. As ELL noted in filed comments, the Company believes the ability to achieve cost-effective savings through DSM programs would be better served by allowing utilities with existing programs to retain control over them. The discussion of DSM, and the potential benefits thereof, throughout this report and in the DSM Potential Study assumes that ELL would still be allowed to administer DSM programs once the Commission's rules are finalized and implemented. On May 4, 2023, the LPSC issued an order extending the current rules until December 31, 2025.

[50] *See,* discussion of Planned Resources, *Id. at* p. 26-28. The Planned Resources include new solar additions approved by the LPSC in Docket No. U-36190, new renewable resources from the 2021 and 2022 ongoing RFPs, and the DER resources approved as part of ELL's Power Through program in Docket No. U-36105.

2023 IRP Reference Resource Plan

Based on the modeling, analysis and findings discussed above, the 2023 IRP supports the conclusion that ELL's future supply-side resources will be focused primarily on renewable energy resources with additions continuing in 2025. The near-term addition of renewables enhances the adaptability of ELL's portfolio to changes, such as rapidly evolving customer demand. It also increases fuel supply diversity, lowers environmental cost risk, and responds to customers' preferences for renewable energy, while also making progress toward meeting the Company's announced sustainability goals, as well as those of our customers. The IRP Reference Resource Plan helps to serve customers in a way that balances affordability, reliability, risk and environmental stewardship. As such, in conducting the IRP and selecting a Reference Resource Plan, ELL considers cost and market risks, in addition to viability, sustainability, executability, and other qualitative risks to determine which portfolio can be most helpful in guiding future resource planning decisions that will deliver reliable service at a reasonable cost and in a sustainable manner. Based on the work conducted as part of the 2023 IRP analysis, it is also reasonable to conclude that demand-side resources will continue to be a component of the capacity portfolio. In the near term, renewable resource additions will be made based on specific project proposals. Over the long-term, the amount of total capacity that will be needed and exactly when that capacity will be needed are uncertain. ELL's Reference Resource Plan maintains the planning assumptions for existing units and continues adding renewable resources starting in 2025 consistent with Portfolio 1 though the exact amount of each type of renewable resource will be based on a market solicitation and may vary from the amounts identified in this analysis.

In conducting the IRP and selecting a Reference Resource Plan, ELL considers cost and market risks, in addition to viability, sustainability, executability, and other qualitative factors discussed in Chapter 5 to determine which portfolio can be most helpful in guiding future resource planning decisions that will deliver reliable service at a reasonable cost and in a sustainable manner. Further, and as is consistent with Section 3 of the Commission's IRP General Order, ELL believes that Portfolio 1 is the "…plan that offers the most economic and reliable combination of resources satisfying the forecasted load requirements".

Portfolio 1 differs from Portfolio 3, primarily due to additional deployment of gas-fired generation, slightly increased Total Relevant Supply Costs, and a slight trade-off in solar and wind deployment. For these reasons, and others, Portfolio 1 is preferred by ELL when compared to Portfolio 3. The differences in Portfolio 1 when compared to Portfolio 2 are much more stark. Notably, Portfolio 2 is constrained so as not to add gas-fired generation, to only to add renewable generation, and ultimately selects considerably more solar, wind and batteries when compared to Portfolio 1, requiring significantly higher capital investment than the other two Portfolios, as shown in Appendix I (Resource Additions Fixed Costs). While Portfolio 2 includes a wider range of potential cost savings, ELL believes that the previously mentioned constraints do not yield an executable resource portfolio, though these do allow for a useful planning analysis exercise that serves to establish a sort of "bookend" for the range of possible outcomes. For example, Portfolio 2 relies on the addition of 1,000 MWs of onshore wind per year from 2027-2042. ELL recently solicited proposals for onshore wind resources in its 2022 Renewables RFP and did not receive sufficient proposals for wind resources to demonstrate the feasibility of assuming that ELL can procure onshore wind resources in such a manner. As such, from an executability standpoint, Portfolio 2 is significantly lacking. Moreover, "the utility's ability to finance the expansion plan" is a relevant concern identified in the IRP Order that is implicated by Portfolio 2.[51] As demonstrated by the total relevant supply cost analysis in Appendix I, the Resource Additions Fixed Cost associated with Portfolio 2 is approximately three times higher than Portfolio 1 – requiring over $7.7 billion dollars on a net present value basis in additional fixed costs.

Another factor relevant to ELL's selection of a Reference Resource Plan is a measure of the market risk exposure of ELL's customers. Refer the section on "Portfolio 2" within Chapter 5 of ELL's Final IRP for a description of the market risk for Portfolio 2 and energy coverage metric, respectively, which notes that Portfolio 2 relies on capacity from the MISO market to a significantly higher degree than the other two Portfolios. As has been described throughout this report, and thoroughly demonstrated in numerous on-going Commission proceedings, reliance on the market for capacity is not a sound resource planning strategy and presents significant risks to reliability of service. Moreover, the recently published price increases in LRZ 9 for the 2023/2024 Planning Year demonstrate that over-reliance on the MISO capacity markets can make customers vulnerable to sudden cost increases, which is another factor that the Commission's IRP General Order directs utilities to consider when selecting a Reference Resource Plan. The consideration of the market risk associated with Portfolio 2 is particularly significant from a reliability perspective due to the increase in reliance on the market by other LSEs in Louisiana.[52] As discussed in Chapter 3 of ELL's Final IRP Report, the risk of a load shed event is exacerbated by the actions of these other LSEs. The market risk, and therefore reliability risk, experienced by ELL's customers would be further increased with the selection of Portfolio 2.

It remains important to keep in mind that the selection of a Reference Resource Plan is not intended to chart a definitive course of action for ELL's resource planning decisions. Nor does the selection of a Reference Resource Plan result in or seek Commission approval of any specific resource procurement. Similarly, ELL's decision in selecting a Reference Resource Plan does not result in any costs being added to customer rates. ELL's selection is merely a planning exercise meant to comply with the Commission's IRP General Order and promote further discussion among ELL, Staff, and other stakeholders.

51 See IRP General Order (6)(h) at pg. 13.

52 See, LPSC Docket No. U-35927, 1803 Cooperative, Inc., ex parte, In re: Application for Approval of Power Purchase Agreements and for Cost Recovery; LPSC Docket No. U-36133, Dixie Electric Membership Corporation, NextEra Energy Marketing, LLC and Amite Solar, LLC, ex parte, In re: Joint Application for Approval of Power Supply Agreements; LPSC Docket No. U-36135, Jefferson Davis Electric Cooperative, Inc. and NextEra Energy Marketing, LLC, ex parte, In re: Joint Application for Power Supply Agreement; LPSC Docket No. U-36514, Concordia Electric Cooperative, Inc., NextEra Energy Marketing, LLC, and Mondu Solar, LLC, ex parte, In re: Joint Application for Approval of Long-Term Power Supply Agreements; LPSC Docket No. U-36515, Pointe Coupee Electric Membership Corporation, NextEra Energy Marketing, LLC, and Mondu Solar, LLC, ex parte, In re: Joint Application for Approval of Long-Term Power Supply Agreements; LPSC Docket No. U-36516, Southwest Louisiana Electric Membership Corporation, NextEra Energy Marketing, LLC, and Beauregard Solar, LLC, ex parte, In re: Joint Application for Approval of Long-Term Power Supply Agreements; LPSC Docket No. I-36503, 1803 Electric Cooperative, Inc., ex parte, In re: 2022 Request to Initiate Integrated Resource Planning Process Pursuant to the General Order (Corrected) dated April 18, 2012 (R-30021).

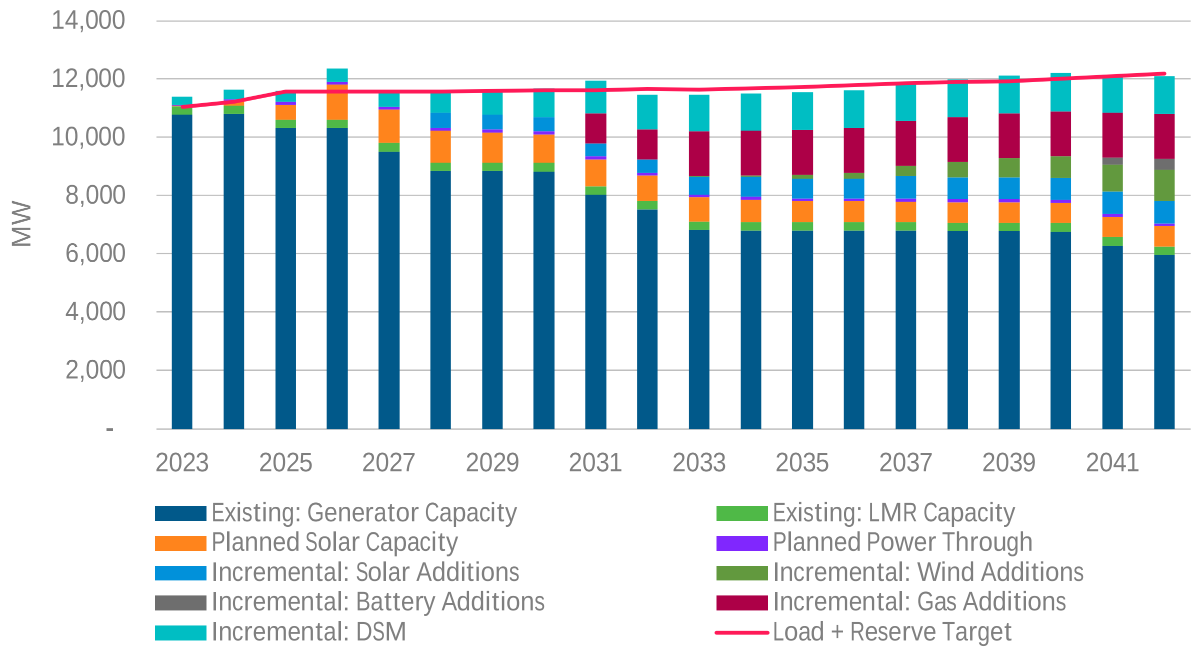

Figure 41: 2023 IRP Preferred Resource Plan

2023 IRP Action Plan

The action items below represent a pragmatic approach to ELL's integrated planning over the coming five years. By necessity, the integrated planning process is subdivided into work streams, each with its own process and timeline.

1. **Implement ELL's Solar Portfolio & Geaux Green Tariff (2020 RFP)**	Pursuant to the recently approved certification, ELL intends to add three new contracted solar resources (Vacherie, Sunlight Road & Elizabeth) and one new owned resource (St Jacques) to its generation portfolio. Additionally, ELL will implement Rider GGO, a new green tariff which will allow participants to subscribe to and receive value from these four solar resources to address their decarbonization objectives. The Company intends to expand Rider GGO and/or develop other renewable options (e.g., the recently proposed Rider GZ) to provide benefits to all customers (including non-participants) and address future capacity needs, where feasible.

2. Complete ELL's Two Outstanding RFPs (2021 & 2022 RFPs)	ELL's 2021 RFP sought up to 600 MWs of solar resources, with an option to provide battery storage, for resources located within SELPA. ELL recently sought certification of the resource proposal that ultimately resulted in an executed commercial agreement, along with another 49 MW solar resource, in Docket U-36685. ELL's 2022 RFP seeks up to 1,500 MWs of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of Louisiana for solar resources, and all of MISO South and/or SPP for wind resources. ELL is in the process of negotiating commercial agreements for resources selected from this RFP and anticipates seeking certification of contracted for resources in late 2023 or early 2024.
3. Continue the Issuance of Sizeable and Frequent Renewables RFPs	ELL intends to continue to issue sizeable and frequent renewable RFPs in an attempt to respond to customer preferences, diversity of ELL's generation portfolio, capitalize on the improving economics of solar and potentially other technologies relative to conventional generation resources, economic development opportunities, and ultimately to work toward its 2030 and 2050 sustainability goals, respectively. In response to the Commission's recent Order,[53] ELL will also work with the Commission and other stakeholders to find ways to expedite this process. Notably, in March 2023, ELL filed an application for the approval of an alternative market-based mechanism process to secure up to 3,000 MWs of solar resources, certification of those resources, potential expansion of Rider GGO and approval of Rider GZ (Docket No. U-36697). In addition, as the market continues to evolve and developers initiate projects, in accordance with LPSC guidelines, ELL will evaluate and respond to any unsolicited offer it may receive for viable renewable resource additions.
4. Cross-State Air Pollution Rule ("CSAPR")	It is anticipated that the Environmental Protection Agency's (EPA) published rule will be the subject of numerous legal challenges in various jurisdictions across the country and it

[53] See Commission Order U-36190 (Dated October 14, 2022) at page 9.

	is uncertain when those challenges will be resolved or what effect they may have on ELL's compliance obligations. ELL will continue to monitor the status of such challenges, as well as related legal challenges to EPA's disapproval of the Louisiana State Interstate Transport SIP for the 2015 ozone NAAQS. In May 2023, prior to the rule being published in the Federal Register, the U.S. Fifth Circuit Court of Appeals issued a stay of EPA's disapproval of the related State Implementation Plan (SIP) developed by the State of Louisiana. This stay will prevent EPA's final CSAPR revisions from taking effect in Louisiana until such time as the stay is lifted. Details associated with the Court's decision and the potential impact thereof can be found in the Inputs and Assumptions section of Chapter 4. As these proceedings unfold, ELL will continue the ongoing process of assessing the impacts of the CSAPR, and the associated challenges thereto, and implementing a compliance strategy to meet any new or revised compliance obligations.
5. Explore Solving Some of ELL's Energy & Capacity Deficits with Distributed Generation and/or Customer Solutions	Distributed generation provides significant benefits to the grid and ELL customers through increased reliability, increased efficiency, grid balancing, peak load reduction and onsite local self-reliance for power generation needs. The LPSC's recent approval of ELL's Power Through program is a great example of a cost-effective opportunity to provide distributed generation coupled with resiliency for its customers. ELL will continue to evaluate opportunities to install distributed generation throughout its service territory as well as seek new opportunities for customer solutions that bring renewable generation, economic development and electrification to Louisiana.
6. Continue Participation in Commission Rulemakings (Resource Adequacy & Planning, Reliability)	ELL intends to monitor and participate in Commission rulemakings regarding resource planning, reliability and resource adequacy and evaluate actions that ELL should take to protect its customers from reliability and cost shifts resulting from cooperatives that plan to serve their load without appropriate long-term physical capacity, including exiting MISO.

7. Explore Additional Demand Side Management Opportunities	ELL stands ready to expand its current DSM offerings in accordance with applicable LPSC Rules[54] and Orders and where it is cost-effective to do so.
8. Pursue Power Resiliency	In December 2022, ELL filed its Entergy Future Ready Resilience Plan highlighting its plan to accelerate the resilience of its electric system through a comprehensive set of cost-effective hardening projects (Docket No. U-36625).

[54] ELL notes that in the on-going rulemaking related to administration of DSM programs (Docket No. R-31106), Staff issued new draft rules on March 7, 2022. Among other things, these draft rules (if implemented as drafted) would radically change the paradigm for administration of DSM programs by removing control of the programs from utilities and seeking to hire a statewide third-party administrator to oversee programs for all utilities. It is unclear whether this model will be implemented. As ELL noted in filed comments, the Company believes the ability to achieve cost-effective savings through DSM programs would be better served by allowing utilities with existing programs to retain control over them. The discussion of DSM, and the potential benefits thereof, throughout this report and in the DSM Potential Study assumes that ELL would still be allowed to administer DSM programs once the Commission's rules are finalized and implemented. On May 4, 2023, the LPSC issued an order extending the current rules until December 31, 2025.

Chapter 7 Stakeholder Engagement

Summary

- Based on feedback received from stakeholders, ELL has worked to enhance the Stakeholder engagement process for this IRP
- Due to the COVID-19 pandemic, all Stakeholder meetings were hosted virtually
- ELL hosted a stakeholder meeting, addressed Q&A, and accommodated multiple stakeholder requests
- ELL has received and responded to stakeholder comments concerning its Draft Report

Pursuant to the LPSC Integrated Resource Plan General Order (Docket No. R-30021 - "Integrated Resource Planning Rules for Electric Utilities in Louisiana"), one component of the development of the IRP is to work collaboratively with stakeholders in ELL's long-term planning process. Stakeholders have the opportunity to ask clarifying questions during a Technical Conference and provide written comments at various stages throughout the IRP process.

The stakeholder engagement process began in November 2021 with a public Data Assumptions Posting to ELL's IRP website.[55] The Stakeholder Kickoff Meeting was held in January 2022 and included a broad amount of information regarding ELL's planning processes and objectives, including preliminary assumptions and inputs for the IRP's modeling. The meeting was well-attended with participation from numerous parties of varied educational and professional backgrounds, representing a wide range of industry experience and expertise. ELL presented extensive information designed to educate stakeholders about resource planning and responded to clarifying questions during its first Technical Conference. Following this meeting, in February of 2022 ELL posted a Q&A document that responded to questions received both during and after the Stakeholder Kickoff Meeting. ELL also provided an updated set of assumptions and inputs in response to feedback provided by stakeholders at ELL's Technical Conference. Responses to written comments provided by stakeholders after ELL's first Technical Conference are provided within (see Appendix A).

ELL filed its Draft IRP Report in October 2022 and held its Second Technical Conference in November 2022. This meeting was also well-attended with participation from numerous parties of varied educational and profession backgrounds, representing a wide range of industry experience and expertise. ELL presented extensive information designed to inform stakeholders as to the contents of its Draft IRP Report and responded to clarifying questions during this Technical Conference. Stakeholders provided numerous written questions, in many instances requesting additional data, and many of these requests did not lend themselves to a verbal response provided in the forum of a Technical Conference. ELL responded to these comments following the Technical Conference and before Stakeholders provided comments to the Draft IRP Report. Responses to comments received at this stage of the proceeding were not required by the IRP General Order, but were provided, and are provided within (see Appendix B).

Lastly, ELL filed its Final Report in May 2023. Stakeholders have provided comments to ELL's Draft IRP Report and responses to those comments are provided within (see Appendix C).

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[55] *See,* https://www.entergy-louisiana.com/irp/2023_irp/ for the information provided by ELL to stakeholders during this IRP cycle

Appendix A – ELL Responses to Stakeholder Comments Prior to Draft IRP Report Filing[56]

Comments Regarding Deactivation and Retirement Assumptions or Evaluations:

Stakeholder Comment	ELL Response
Staff: ELL should provide, in its Draft IRP, an explanation of why some deactivations are designated as confidential.	After considering stakeholder input, ELL has no longer designated any of its deactivation assumptions over the next 10 years in this Draft IRP as confidential. See Table 3 (within Chapter 3) for these assumptions.
Sierra Club: ELL should evaluate earlier retirement options for White Bluff, Independence, Nelson, and Big Cajun II, perhaps as a sensitivity, as was done in EAL's IRP.	ELL does not have majority ownership interest in White Bluff, Independence, or Big Cajun II. Therefore, it is not appropriate or meaningful to the IRP analysis to speculate on or analyze alternate deactivation assumptions for those units. Table 3 in the IRP main body documents the deactivation assumptions for these units. Regarding Nelson 6, the purpose of the IRP analysis is not to analyze or optimize near-term deactivation assumptions for individual units, but rather to identify long-term resource portfolios and strategies that are economic for ELL customers under a range of market conditions, as confirmed in the current IRP Rules.

Comments Regarding Energy Efficiency and DSM:

Stakeholder Comment	ELL Response
AAE: Pre-pay is a "predatory program" that allows utilities to avoid consumer protections related to disconnections and should not be approved as a DSM program. It can also harm LIHEAP benefits.	ELL disagrees with AAE's characterization of pre-pay programs. ELL further notes that for purposes of this IRP, pre-pay is one of many EE/DSM measures that were evaluated by ICF within the DSM Potential Study contained in Appendix I. If ELL elects to propose a pre-pay program at a later date, any such proposal will be subject to LSPC approval.
AAE: Entergy's Final Integrated Resource Plan should fully address robust and equitable energy efficiency programs to reduce bills and protect health and safety.	See the discussion of DSM resources throughout this Draft IRP Report and in ICF's DSM Potential Study contained in Appendix L.
AAE: ELL should evaluate the savings identified in the DSM Potential study against the supply-side resources proposed in its data assumptions. This includes EE, DR and DER.	ELL did conduct such an evaluation of savings in this Draft IRP Report. Please see the DSM Potential Resource Assessment section of Chapter 4 and the DSM Modeling section of Chapter 5 for additional information about the Draft IRP analysis.

[56] It should be noted that Appendix A has not been updated to reflect additional developments that occurred after ELL responded to these comments initially. Updated information related to Stakeholder comments is contained in Appendices B and C.

AEMA: EV resources should include participation beyond smart chargers.	ICF modeled the EV program with the chargers as the primary operating device since the other program delivery modes (e.g., using telematics) are still nascent. However, to account for the fact that there might be growth in these additional program delivery options, the steady state/max market share in the reference and high cases were set to capture the range of possible levels over which participation could vary with current and further implementation designs. Regarding the cost-effectiveness difference in EV programs with telematics, a significant portion of the savings comes from not having to purchase chargers to participate in DR programs. ICF modeled program TRC with and without the cost of chargers, and in both scenarios the program doesn't clear the TRC test.
AEMA: More explanation should be given as to why residential battery storage did not pass the TRC test	The battery storage program evaluated within ICF's report (in Appendix I) reflects the high upfront costs for the customer due to the cost of the battery and the installation. Due to slower adoption of batteries, compared to more prevalent technologies like smart thermostats, the high upfront costs are not offset by the capacity benefits thus resulting in a TRC ratio significantly less than 1.
AEMA: Battery storage should include additional value streams beyond demand charges.	ICF considered demand charge reduction as the sole customer savings (or revenue creation) stream in its analysis. It did so for two reasons. First, ICF anchored its analysis of commercial and industrial ("C&I") standalone battery storage in ELL's most common present rate structures and present market opportunities. As a principle, ICF did not model different rate structures for battery storage than currently exist to avoid inconsistency with modeling across other parts of ICF's potential study and with broader elements of the utility's integrated resource planning process. Regarding wholesale price arbitrage that may become available when MISO provides market access under FERC Order 841, ICF felt that any rules and valuation for that revenue stream would be too speculative to include in the potential study at this time. The second reason that ICF concentrated on the demand charge reduction use case is that it has been the most prevalent one for C&I battery storage in many markets.[57][58] Moreover, the size (power capacity) and duration of the prototype standalone C&I battery system in ICF's analysis was established to maximize economic use for batteries under the utility's C&I rate schedules with relatively high monthly peak demand charges.
AEMA: Cost-effectiveness assumptions for residential batteries should be made more transparent.	See the discussion of residential battery resources within the DER portion of ICF's Potential Study contained in Appendix L.

[57] Galen Barbose, Salma Elmallah, and Will Gorman, Behind-the-Meter Solar + Storage, Lawrence Berkeley National Laboratory (July 2021), available at https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf

[58] National Renewable Energy Laboratory, *Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges,* U.S. Department of Energy (August 2017), *available at* https://www.nrel.gov/docs/fy17osti/68963.pdf

AEMA: DR aggregation should be more fully considered for C&I and residential customers.	DR aggregation was considered and modeled by ICF. See the discussion of DR aggregation (for the C&I interruptible program) within the DR portion of ICF's Potential Study contained in Appendix L.
AEMA: DER applications should include aggregation of resources. AEMA: Order 2222 should be considered as one of ELL's futures in MISO that could have a significant impact on the IRP. SEES: ELL should develop and include at least two model implementations of Distributed Energy Resource Aggregations (DERAs) in ELL territory to illustrate inclusion of resources allowed by FERC Order 2222	Aggregation of DER resources was not included in the DER potential study. Uncertainties in how FERC Order 2222-related tariffs will be defined and implemented in the MISO territory are still significant and create challenges in estimating potential outcomes on the level and timing of system loads. While AEMA correctly notes that ELL is actively involved in the MISO process around Order 2222, the extended timetable for final MISO action on Order 2222 maintains a high degree of uncertainty.
AEMA: Additional DER technologies such as community solar and microgrids should be included.	For microgrids and community solar, there are three reasons that they were not modeled in the Draft IRP analysis. First, many of the underlying technologies in both microgrids and community solar (e.g., solar PV, battery storage, demand side management) are already accounted for within the DSM and DER forecasts in ICF's Potential Study. Therefore, an independent microgrid or community solar forecast would need to exclude the customary impacts of those technologies to avoid double-counting. Second, to estimate the incremental impacts of microgrids would require detailed data on their expected hourly operation, which is not readily available. Third, microgrids and community solar are not standardized. They tend to be deployed at vastly different scales, with different underlying amounts of distributed generation. Furthermore, microgrids can be deployed with various load control technologies and with different operating rules and economic, environmental, and resilience objectives. Therefore, making annual growth assumptions about the number, scale, and impacts of microgrids and/or community solar is not likely to be accurate.
AEMA: Additional DERs should be addressed for resilience (e.g., winter Storm Uri) and net zero carbon benefits.	While the DER potential studies did not include distinct value streams for resilience and net zero carbon benefits, their methodologies rely on market acceptance curves that implicitly include various customer motivations for adopting clean energy measures. Those motivations often include energy bill savings, energy cost certainty, environmental improvement, resilience against power outages, and grid independence. The high scenarios in the DER modeling, in particular, can be thought to more highly value factors like environmental improvement and resilience because their market acceptance curves are heavily influenced by higher DER penetration markets with relatively low carbon grids and more pairings of solar and battery storage that offer resilience

Comments Regarding the Evaluation Process:

Stakeholder Comment	ELL Response
LEUG: Entergy shall identify and describe significant transmission constraints and limitations within its system and discuss any actions that could be taken to eliminate the constraints and/or limitations.	Specific transmission constraints on the ELL system, both reliability and economic, along with proposed projects to mitigate them, are described in MISO's annual MTEP report.[59]. These constraints and mitigations are analyzed through Entergy's Long-Term Transmission Planning and MISO's MTEP processes, as described in the Transmission Planning section within Chapter 3 of this Draft IRP Report. Details of the Transmission Study processes are included in Chapter 1 of the annual MTEP Report, and details of the ELL constraints and mitigation projects are included in the South Region discussion portion of the MTEP report.
LEUG: Entergy should provide some measure of rate impacts for the Reference Resource Plan and the alternative resource planning scenarios evaluated.	Please refer to Appendix I.
LEUG: Entergy should identify and describe any Reliability Must Run units that it operates and discuss any actions that could be taken to eliminate the RMR units.	"Reliability Must Run" is a legacy term that predates ELL's participation in MISO. In MISO, out-of-market unit commitment for reliability reasons is classified based on the reasons for such commitment – e.g., Voltage and Local Reliability. ELL interprets this question and its reference to "Reliability Must Run units" (as well as the reference to this term in the IRP General Order, which order also predates ELL's participation in MISO) as addressing out-of-market unit commitment that may occur for a variety of reliability-related reasons. The Amite South, DSG and WOTAB operating guides each provide a list of generation units which may be committed for thermal and/or voltage support (which is comparable to a list of potential "RMR" units in the areas served by ELL). The constraints described in these operating guides are the primary drivers of these "RMR" commitments. RMR commitment procedures are dependent on regional characteristics which change over time. These characteristics include (without limitation) load growth, resource start up times, and resource availability. There are several transmission projects in the MISO planning processes that are expected to help mitigate the constraints listed in the Amite South and DSG Operating Procedures.

[59] *See,* www.misoenergy.org/planning/planning

SEES: ELL's IRP should look beyond planning for capacity needs only, when executing lowest reasonable cost planning. SEES: ELL should run manual portfolios rather than the traditional IRP model runs that seem to only add capacity when there is a capacity need. This can allow for zero-marginal-fuel resources to be added and provide benefits sooner than capacity only modeling	ELL agrees and ELL's optimized portfolios do this by identifying the lowest cost resources that meet ELL's planning reserve margin and customers' energy needs, subject to constraints. In the event that ELL receives opportunities to add cost-effective resources that meet customers' energy needs and provide benefits to customers, it will evaluate and consider such opportunities. The Company acted accordingly in the case of the Elizabeth Solar PPA, which was approved by the LPSC in September 2022. However, ELL notes that adding resources beyond ELL's customers' needs for capacity and/or energy may expose ELL's customers to inappropriate and unnecessary market price risk. Zero-marginal-fuel-cost resources, such as solar and wind are considered and included in the optimized portfolios when appropriate; however, these resources have fixed costs that must and are also considered in the evaluation.
SEES: ELL's IRP methodology leads to a siloed approach to resource planning.	ELL follows the rules of the IRP as laid out in the Commission order. The IRP is a planning tool developed at a point in time and is used to develop solutions for ELL resource planning but is not the only consideration when planning for long-term resources.
SEES: ELL's IRP modeling appears to be siloed from planning in the MISO market. Further, ELL should take advantage of MISO's LRTP and provide analysis on what benefits these projects could bring to the region, it should model an expansion of the North / South constraint, and it should include a market congestion study that alleviates load pockets throughout ELL territory.	The ELL IRP modeling is based on a planning reserve margin target that was determined by a study that modeled the entire MISO system. For this reason, the IRP does account for the reserve margin benefits of participating in the MISO market. Please see the Transmission Planning Section in Chapter 3 for more information.
LEUG: Entergy should identify whether its IRP modeling assumptions include all transmission reliability and congestion projects that have been approved by MISO. SREA: ELL should incorporate local, intraregional, and interregional transmission planning. Staff: ELL does not consider transmission options as a viable alternative to generation, as required by the IRP rules. ELL should provide transmission topology assumptions, the cost of a selection of transmission alternatives, and future MISO projects	Transmission is not a viable alternative to generation. Transmission facilities do not possess the ability to generate electricity. Please also refer to ELL's discussion of the transmission planning process conducted in coordination with MISO in the Transmission Planning section of Chapter 3 within this Draft IRP Report. As is discussed therein, ELL must coordinate transmission planning within that process. Please see Appendix D – MISO MTEP Submissions for a description of the transmission projects approved or submitted through MISOs MTEP process. The analysis performed for the resource portfolio design included in the IRP document is based on evaluating ELL's projected capacity and energy needs. Transmission plans are only approved for the next 5 years; whereas, this long-term IRP assessment is performed for the next 20 years. Relying on a transmission system that is unchanged after five years is insufficient when performing a 20-year IRP assessment. Other analyses which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning, and may apply the transmission topology in the AURORA Nodal Model construct, including approved MISO MTEP projects.

Comments Regarding LPSC IRP Rules and ELL Policy:

Stakeholder Comment	ELL Response
AEMA: There should be additional opportunities for stakeholders to engage and provide data based on deployment experience.	Please see Chapter 7 of this Draft IRP Report.
SEES: The staggered nature in which ELL provides data leads to a stakeholder process that is out of sync with opportunities for comment. Specifically, if more data was presented to parties in advance of the meeting about underlying assumptions around demand side resources, load growth, capacity additions, electrification tech adoption, generation resource types, federal tax incentives and renewables assumptions, there may have been a better grounding for next steps in the IRP process.	ELL provided its Data Assumptions, per the schedule established in the LPSC's IRP General Order (Docket No. R-30021) in November of 2021. ELL held its Technical Conference in January 2022 and filed Updated Data Assumptions, in part due to feedback received at the Technical Conference, in February 2022. Due to the filing of this Updated set of Data Assumptions, and also due to the timing of the Commission's hiring its outside consultant in the matter, ELL noted its openness to delaying the date by which stakeholders were to provide comments on ELL's data assumptions. As a result, Staff subsequently extended the deadline for comments by three weeks in a Notice of Revised IRP Dates, issued on February 16, 2022.
Sierra Club: The Commission should change the IRP Process to incorporate additional stakeholder feedback (i.e., "while modeling is being conducted") and that ELL should hold two interim stakeholder meetings between now and the draft IRP filing with the understanding that the input from stakeholders will be considered throughout the modeling process leading up to the Draft IRP filing.	Please see Chapter 7 of this Draft IRP Report. In addition, the Company has followed the schedule established in the LPSC's IRP General Order (Docket No. R-30021) and has provided opportunities for additional time and feedback from stakeholders as noted above.
SREA: A docket should be opened to begin reforming the Louisiana IRP process.	The Commission has already opened a rulemaking to consider a change to the IRP rules (Docket No. R-36362), in which SREA intervened on February 18, 2022.

Comments Regarding Model Inputs and Data Assumptions:

Stakeholder Comment	ELL Response
AAE: Entergy's Final Integrated Resource Plan should fully address realistic resource costs, including gas, hydrogen, renewable, and battery storage assumptions, and further encourages Entergy to use NREL Annual Technology Baseline as a transparent and up to date reference material for these cost assumptions. AAE: AAE noted that it is concerned that ELL's data assumptions lack clarity as to the derivation and costs of hydrogen. Sierra Club: ELL should include costs for converting existing units to hydrogen, necessary infrastructure and all variable costs associated with hydrogen including the fuel itself.	Within the context of the IRP and for the purposes of long-term resource planning, ELL finds that the costs assumed for "Gas and Hydrogen" and "Renewables and Energy Storage" resources are both realistic and comparable to multiple industry resources, including NREL ATB. Gas and Hydrogen costs are derived from an engineering consultant with extensive industry experience, including development of natural gas with hydrogen capability plants. When comparing the total installed costs estimated by NREL ATB with ELL's assumption for solar, wind, and battery resources, the costs adopted by ELL is lower than or comparable to costs assumed by NREL ATB across all resources. Additionally, within the purpose of the IRP, it is not relevant to evaluate costs for converting existing natural gas units to enable hydrogen firing capabilities, rather it is appropriate to estimate the costs to incorporate hydrogen optionality into new, future units. ELL's estimated costs for "Gas + Hydrogen" resources include costs to incorporated hydrogen-capability in natural gas units, but not costs required to burn hydrogen.
AAE: ELL's assumptions for natural gas costs are not aligned with the reality of international gas markets, especially as Louisiana LNG terminals continue to gain customers.	Natural gas price forecasts are based on the consensus of independent, third-party consultant forecasts that take into account fundamental factors such as those described, along with others that may affect the supply and demand for natural gas. In addition to using multiple consultant forecasts, a range of natural gas price forecasts are used in the evaluation to provide information on the sensitivity of results relative to natural gas price assumptions. Future gas price forecasts are expected to reflect higher near-term prices consistent with current market conditions, while long-term prices will remain a function of the fundamentals included in the consultant forecasts.
LEUG: Entergy asked to address in the IRP the effect on its future resource planning from known significant generation additions being pursued by third parties within or near its service region, including Magnolia Power CCGT and several solar projects included in the approved future power supply for 1803 and reserves the right to further address Entergy's resource planning including consideration of Entergy analysis of such generation additions to the region.	Capacity Expansion in ELL's IRP seeks to identify the resource plans and strategies that are available to and controllable by ELL to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to consider specific incremental resources that are owned and controlled by others as potential additions to ELL's portfolio. However, all MISO market resources are appropriately considered in the context of their participation in the MISO energy and capacity markets and their effect on ELL's long-term resource planning.

LEUG: LEUG asserts that Entergy assumes acquisition of a second BOT of 600 MW to be in service in 2025. LEUG further approximates the cost of BOTs on an installed $/kW basis and asserts that solar resources will cost more than new CCGTs on a $/kW basis.	The resource additions identified on slide #10 of ELL's Updated Data Assumptions presentation were intended to reflect: 1) approved resource additions (Carville Renewal), 2) resources that ELL was seeking certification for at the time of the Updated Data Assumptions filing (ELL Power Through, Sunlight Road PPA, Vacherie PPA, and St. Jacques Solar BOT), 3) resources sought in ELL's 2021 Solar RFP, and 4) the 2027 ELL CT. However, following the technical conference ELL furthered negotiations on selections out of the 2021 Solar RFP and announced the ELL 2022 RFP, as a result ELL has elected to include the resources in negotiations from the 2021 Solar RFP as well as the 1,500MWs sought in the 2022 Renewable RFP. As a placeholder and until further information is known, all 1,500MWs are assumed to be solar resources and the ownership is assumed to be 50% PPA resources and 50% BOT resource. Additionally, regarding the 2027 ELL CT, that resource has been removed as a "planned resource" and ELL has elected to allow for its IRP process to solve for capacity that might be needed within the time frame that the CT was originally assumed to provide that capacity. The decision to remove this resource as a "planned resource" was made, in part, due to the recognition that the Magnolia CCGT would be located within ELL's SELPA and would provide some of the benefits to the SELPA transmission system that the 2027 ELL CT had intended to provide. Lastly, the comments here in compare an assumed cost of solar resources to the historical cost of CCGTs. While that cost comparison may provide an interesting data point, it only compares the fixed costs of the resources and ignores the variable cost, capacity value, energy value, and potential effect on load payments. Only though the evaluation of each of these factors and their effect on ELL's total relevant supply cost can the lowest cost resource be determined.

SEES: ELL's IRP should use up-to-date inputs from NREL's Annual Technology Baseline (ATB), appropriate to the resource zone where ELL is located. SEES: NREL data should be used to inform the IRP, as it contains "up-to-date capital cost assumptions" Sierra Club: ELL should use NREL 2021 ATB data when modeling on-shore wind and that it should model higher quality wind, relative to wind in MISO South, like a PPA for wind in SPP. SREA: ELL use the National Renewable Energy Lab Annual Technology Baseline data for solar, solar+ storage/hybrid, onshore and offshore wind, and battery resources. - Use multiple configurations of these technologies, including self-build options and PPA options - When modeling PPA options, use the NREL ATB LCOE values as $/MWh inputs	The point in time from which data inputs are sourced by ELL for the IRP is dependent on the timing requirements set forth by the Commission for the IRP process to finalize data assumptions, which may differ from ELL's annual Business Plan process and release of new data by industry sources, including NREL ATB. When comparing the total installed costs estimated by NREL ATB on a nominal basis with ELL's assumption for solar, wind, and battery resources on a nominal basis, the costs adopted by ELL are lower or comparable across all resources than those assumed by NREL ATB. ELLs IRP seeks to identify the resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
Sierra Club: ELL over estimates the cost of renewables and should evaluate model PPAs, as opposed to self-builds only, in its IRP. PPAs are lower cost due to ITC treatment and other reasons. Achieving the lowest reasonable cost is only possible when PPAs are considered.	ELLs IRP seeks to identify the resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
SREA: ELL should manually build the MISO market using the MISO MTEP Futures 1, 2 and 3, and/or use MISO's own LMP data.	ELLs IRP considers a range of possible future scenarios that are intended to identify and evaluate a range of portfolios and portfolio strategies to meet ELLs customers' needs across a range of possible future outcomes. There is no basis to believe that MISO Transmission Expansion Plan Futures or any other possible future scenario would provide better information than the future scenarios used for ELLs IRP.
SREA: ELL should improve capacity value accreditation methodologies for all resources.	ELL aligns capacity accreditation methodology with MISO. Solar portfolio capacity accreditations aligns with MISO MTEP21 Methodology. ELL is closely monitoring MISO's non-thermal accreditation reform proposal for implementation in future planning efforts.

SREA: ELL should improve natural gas accreditation, fuels costs, and hydrogen assumptions	ELL develops natural gas price forecasts based on the consensus of independent, third-party consultant forecasts that consider fundamental factors that may affect the supply and demand for natural gas. In addition to using multiple consultant forecasts, a range of natural gas price forecasts are used in the evaluation to provide information on the sensitivity of results relative to natural gas price assumptions. Coal price forecasts are developed based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. Hydrogen capability is included for all new, large-scale generators that can utilize hydrogen for fuel. It is currently premature and unnecessary to forecast hydrogen fuel prices and model burning hydrogen to generate energy.
SREA: ELL should appropriately evaluate transmission interconnection costs for all generation resources. Staff: For solar resources, ELL arbitrarily includes a $100/kW transmission adder for solar; this should be supported by data or removed. LEUG: Entergy asked to perform a sensitivity study or run analysis with reasonable ranges of potential transmission costs associated with its data assumptions for solar and wind resources.	ELL includes interconnection costs for all generation technologies included in the IRP. For solar resources, ELL uses reasonable assumptions based on feedback from consultants and data and inputs to the Company's technology assessment as well as information from its Transmission organization. Specifically, the $100/kW interconnection cost for solar assumes a switch yard, a small generator step-up transformer located next to the point of interconnection, and a tie-line to facilitate a 115kV, 138kV, or 230kV interconnection.
Staff: Staff requests ELL clarify its response regarding the use of solar PPAs as a "starting point" for costs in the IRP	ELLs IRP seeks to identify the long-term resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
Staff: ELL should include, in its Draft IRP, support for the assumption of why environmental allowances declined in 2024 and remained flat throughout the rest of the outlook.	NOx emission allowances are limited based on the revised CSAPR update rule that was issued by the EPA in March of 2021 and a new regulatory proposal to revise CSAPR issued by the EPA on April 6, 2022. These changes are described in the Draft IRP section on CSAPR.

Staff: ELL should provide an example of how capacity value forecasts are used in IRPs	ELL's long-term capacity value is used to estimate the cost or benefit associated with normalizing the amount of capacity represented in each portfolio optimized for ELL. Differences in portfolio capacity can arise due to the discrete size of the resources selected by Aurora's capacity expansion algorithm to meet the required reserve margin. Cross testing the optimized portfolios in the alternative Futures results in surplus or deficit capacity positions relative to the required reserve margin because the peak load forecasts are designed to vary across the Futures. Capacity value is used to normalize the surplus or deficit capacity positions relative to the required reserve margin when the Total Relevant Supply Cost is determined to mitigate the effect of the surplus or deficit capacity positions and allow comparison of the portfolios on a consistent basis.
Staff: ELL needs to provide capacity factor assumptions for gas units	As a result of this comment the capacity factor assumptions for gas units were included in the "Updated Data Assumptions" file provided February 11th, 2022. Please note the capacity factor assumptions for non-renewable resources are not inputs into Aurora, but rather used to calculate indicative LCOE and, instead, are an output of the AURORA modeling.

Comments Regarding Portfolio Alternatives:

Stakeholder Comment	ELL Response
LEUG: ETR resource planning should utilize Industrial customer programs that could offset some of the need for Entergy to construct new generation and thus avoid costs for all ratepayers. LEUG: LEUG: Entergy should include 1) Industrial customer market access options, 2) enhanced CHP opportunities, and 3) PPAs by industrial customers with third-party renewable developers, as viable resource planning resource alternatives.	Some of LEUG's requests go beyond the scope of this IRP process and in fact run contrary to a primary purpose of this process, maintaining a reliable electric system for Louisiana customers. The Commission is presently examining (or re-examining) some of the issues and ideas LEUG raises in several concurrent dockets, where ELL has provided extensive data and commentary. As discussed herein, the MISO capacity market is not designed to provide compensation for the full cost of generation resources. Rather, MISO relies on utilities within its market to provide the resources needed to ensure reliability through long-term resource planning under the regulation of state commissions. Therefore, allowing a select set of customers access to the pricing of the MISO market, rather than paying full retail rates, would allow those customers to avoid the full cost of the generation needed to reliably serve all Louisiana customers. The customers not offered that option would then be forced to pay for the total cost of generation or, alternatively, the utility would refuse to continue building generation needed for reliability and for which its customers would receive an undue share of the costs. The result of the latter option is a lack of local generation needed to serve customers. This IRP process is intended to achieve the opposite result. That being said, the Company is willing to explore tariff options that provide access to renewable resources and do not result in the cost shifting noted above.

SEES: ELL should include PPA pricing data for the MISO market to establish a 'Market Resource' type for inclusion under the types of generation resources being considered for analysis in the IRP.	Excess capacity available through MISO is not guaranteed from year to year much less in the long-term and exists, partially, as a function of proactive planning actions of regulated utilities such as ELL. Accordingly, excess market capacity is not considered to be a viable option for meeting long-term planning objectives such as the reserve margin. Resource alternative inputs to the model are developed from a financial perspective assuming utility ownership. However, the type and timing of capacity is what the model is solving for, not the optimal ratio of PPA/ownership. The portfolios are indicative of what types of resources would be preferred under certain conditions. The decision to procure said resources would occur through competitive solicitations consistent with the Market Based Mechanisms Order ("MBMO") and may include self-build alternatives as well as PPAs.

Comments Regarding Scenarios, Sensitivities, and Risk:

Stakeholder Comment	ELL Response
AAE: Entergy to create at least one scenario or manual portfolio to guide the swift retirement of expensive and emitting resources in order to reach state and its own corporate climate goals.	Each optimized resource portfolio modeled in connection with the Draft IRP Report maintains consistency with the referenced goals. While assessing early deactivation of resources is not within the scope of the Commission's current IRP rules (deactivations are considered in individually docketed proceedings, such as Docket No. X-35643, which assessed the economics of early deactivation for certain legacy units), it should be noted that each Future assumes deactivation of all coal units by 2030.
SEES: ELL's IRP should Include indicative LRTP transmission lines in in ELL territory, in the IRP as a sensitivity, using the resulting Adjusted Production Cost (APC) as the cost data for existing generation versus capital cost for new generation with the LRTP lines included.	The approved MISO LRTP transmission projects do not benefit MISO-S and ELL is located in MISO-S. MISO's LRTP and APC planning processes are designed to identify transmission expansion projects and would not be appropriate for use in developing ELL's IRP that seeks to identify the resource plans and strategies to serve ELL's customers.
SEES: As a scenario, ELL's IRP should include MISO MTEP Future 3 for the purposes of helping to align with Entergy's Net Zero by 2050 corporate goal. The modeling of the MISO market through the MTEP Futures is the closest modeling to net zero by 2050 that has been produced so far for the region, and ELL should use it.	ELL's IRP considers a range of possible future scenarios that are intended to identify and evaluate a range of portfolios and portfolio strategies to meet ELL's customers' needs across a range of possible future outcomes. There is no basis to believe that MISO Transmission Expansion Plan Future 3 or any other possible future scenario would provide better information than the future scenarios used for ELL's IRP.

SREA: ELL should create several "manual portfolios" for ELL to respond to the MISO MTEP Futures - Manual portfolios should add more renewable energy sooner, rather than later - At least one manual portfolio should achieve Entergy's net zero carbon emission goal	ELL did not see a need for manual portfolios for the IRP. Further ELL notes, Future 2, described in detail in Chapter 5, only allows for non-emitting resources to be selected through capacity expansion. The first resource selected in this portfolio is in 2025. In addition, all three portfolios are consistent with and make progress towards Entergy Corporation's announced sustainability and emissions reductions goals.

Other Comments:

Stakeholder Comment	ELL Response
AAE: Entergy's Final Integrated Resource Plan should fully address Alignment with other Entergy planning efforts, including transmission, distribution, resilience/reliability, retirements, and any others that the company undertakes outside the Integrated Resource Planning process.	Please see the discussion of the coordination between these functions throughout this Draft IRP Report.
AAE: AAE would like to see, fully addressed in Entergy's Final Integrated Resource Plan, IRP alignment with climate/greenhouse gas goals, including Entergy Corporation's own carbon emissions goals and the goals outlined by the Climate Initiatives Task Force SEES: ELL's IRP is not coordinated with announced corporate sustainability goals by Entergy Corporation and is "run in a way that limits its ability to align" with these goals.	Please see the above responses and the discussion in Chapter 5 in this Draft IRP Report. The work conducted through this process (including the results of all three portfolios) align with the Company's stated goals.
Business Network for Offshore Wind provided a variety of comments supporting the continued development of offshore wind. Notably, they stated that offshore wind provides utility-scale renewable and cost-competitive energy that can help a state achieve its net-zero emission goals while growing the economy and creating jobs	Please see ELL's discussion of offshore wind in the Technology Evaluation and Selection section of this IRP and also the discussing of partnerships ELL is currently pursuing related to offshore wind.

LEUG: IRP modeling should not be used as a basis to circumvent analysis of resources available in the market.	The LPSC Corrected General Order for Docket No. R-30021: In Re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities ("IRP Docket") states beginning on page 2, "The goal of the IRP is to develop a defined resource plan, and the Action Plan is intended to specify implementing actions that the utility should take, however Staff recognizes that these rules are not intended to replace or modify the normal docketed resource certification process, and a statement to this effect is included in the Action Plan section." ELL utilizes a separate docketed resource certification process, in accordance with the requirements of the MBM Order, for certification of the resources identified in the Action Plan that ELL chose to pursue.
LEUG: The IRP process is not a substitute for LPSC certification process and procedure and that it reserves all rights to conduct discovery and fully evaluate Entergy data assumptions and resource plans in individual resource certification proceedings and/or any other future proceedings that address Entergy resources and plans and whether such plans are prudent and in the public interest.	ELL has not proposed that the IRP be utilized as a substitute for the current Commission certification requirements outlined in the 1983 General Order or the Market Based Mechanisms Order.
LEUG: LEUG notes that it reserves the right to further address Entergy's resource planning based on the outcome of the LPSC rulemaking on minimum physical capacity thresholds, docket R-36263.	ELL's IRP and the planning conducted herein is based on rules currently in effect at the time the analyzes underpinning the IRP are performed. To the extent the Commission adopts new rules during the pendency, or following the completion, of ELL's IRP, it would be inappropriate to assess ELL's IRP Report under rules that did not exist when this process commenced.
SEES: The degree to which ELL was unable to answer questions from stakeholders raises concerns about the IRP process.	ELL conducted a stakeholder meeting that lasted over eight hours and answered a multitude of questions from stakeholders during this time as well as in writing following the meeting.
SEES: ELL's stakeholder meeting seemed to drag through some sections, and be rushed toward the end.	ELL will endeavor to be more mindful as to the flow of future stakeholder meetings.
Sierra Club: ELL should analyze the public health impacts within its IRP, especially in environmental justice communities. ELL can use the EPA's EJSCREEN tool to evaluate "a particular power plant."	The EPA's EJSCREEN tool is utilized to evaluate specific resources with known locations. The IRP does not consider or attempt to identify specific locations for the resource types included in the optimized portfolios.

Sierra Club: ELL should issue an all-source RFP or RFI for the purpose of gathering up-do-date market intelligence to inform the costs of new resources (i.e., the bids could "inform Entergy's modeling in the 2023 IRP") and "allow for effective competition" in its IRP.	A key objective of adequate and prudent resource planning for any utility is long term resource planning. ELL actively monitors and assess the needs of its system, age and type of resources, and balances this against reliability, affordability, and environmental stewardship. Every 4 years, as ordered by the LPSC, ELL produces a voluminous IRP describing this process, provide analytics for resources available to meet load needs and associated costs. These processes, which rely on multiple industry sources for technology costs, inform the technologies that best match the load need from a locational, economic, and technology perspective. As resources are needed and proposed for deployment, ELL issues an RFP to solicit market-based proposals for the type of resources that meet its supply need(s). ELL does not rely on all-source RFPs to replace prudent utility planning and decision making and instead solicits resources that are adequately suited to meet the needs of its customers.
Staff: Staff noted that it asked ELL if it had performed or provided analysis of the economics of historical and continued operations of each of its plants, and whether the going forward analysis accounted for the cost to comply with future environmental regulations. Further, Staff recommended that ELL should provide this information in its Draft IRP.	ELL does perform analysis of the economics of the continued operations of its plants including any necessary environmental compliance investments; however, these analyses are not performed within the context of the IRP (deactivations are considered in individually docketed proceedings, such as Docket No. X-35643, which assessed the economics of early deactivation for certain legacy units). As planned deactivation dates near, a significant equipment failure occurs, or operating performance diminishes, a reassessment of deactivation assumptions may be required. Unit-specific portfolio decisions, e.g., sustainability investments, environmental compliance investments, or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, the reliability of the system, and the cost of supply alternatives.
Staff: ELL should provide, in its Draft IRP, a historical representation of its load served so that it might be compared to its load forecast.	Please see Appendix H.
Staff: ELL should provide, in its Draft IRP, its historical cumulative average percentage growth rate (“CAGR”) for the past 10 years.	Please see Appendix H.

Appendix B – ELL Responses to Stakeholder Comments and Questions Submitted in Conjunction with the 2nd Technical Conference[60]

Comments Regarding Existing Units:

Stakeholder Comment	ELL Response
Sierra Club: For each of Entergy's (sic) solid-fuel units: a) Has the Company undertaken any analysis of the costs of compliance with EPA's Effluent Limitations Guidelines or the Coal Combustion Residuals Rule. If so, please provide all such analyses and state the total cost of the projects, by unit, the Company intends to undertake. b) Has the Company undertaken any analysis of the costs of compliance with EPA's Good Neighbor Rule or Transport Rule under the 2015 National Ambient Air Quality Standard for ozone. If so, please provide all such analyses and state the total cost of the projects, by unit, the Company intends to undertake. c) Has the Company undertaken any analysis of the costs of compliance with EPA's Regional Haze Rule for the second planning period. If so, please provide all such analyses and state the total cost of the projects, by unit, the Company intends to undertake.	a) Please see the "Environmental" section within Chapter Four of ELL's Draft IRP. b) Please see the "Environmental" section within Chapter Four of ELL's Draft IRP. It should be noted that the requested unit-specific analyses are beyond the scope of what is contemplated in the Commission's IRP General Order. c) Please see the previous response.

Comments Regarding Inputs and Data Assumptions:

Stakeholder Comment	ELL Response
LEUG: Please identify and provide the total $ installed cost assumed for each of the generation capacity additions identified for Optimized Portfolio 1 on page 85 of the Draft IRP, by resource type - - 2x1 CCGT, 1 xl CCGT, CT, Solar, Onshore Wind, Hybrid, Battery.	See Table 11 and Table 12 of ELL's Draft IRP.

[60] ELL responded to these comments following the Technical Conference and before Stakeholders provided comments to the Draft IRP. Responses to comments received at this stage of the proceeding were not required by the IRP General Order. Figure references in stakeholder comments refer to figures in ELL's Draft IRP, not this Report.

LEUG: Concerning Figure 9 on page 33, please provide a tabulation showing the values for each time period for each of the four lines on the graph. Please also provide workpapers supporting the derivation of these numbers.	Regarding the requested tabulation, please see the response to question 11 above. ELL further notes that the request to provide workpapers is not within the scope of what is contemplated in the Commission's IRP General Order, and the workpapers and data requested contain market sensitive information which ELL is not able to provide.
LEUG: Concerning Figure 10 on page 35, please provide a tabulation showing the numerical values for each of the five values plotted, for each year of the period 2023 through 2042.	Please see the additional tables included in Appendix K.
LEUG: Concerning Figure 11 on page 36, please provide a tabulation showing the numerical values for each of the seven values plotted, for each year of the period 2023 through 2042. For each year, please identify the facilities and their capacity that constitute the gas total, the solar total and the contracts total.	To the extent the requested information is contemplated within the scope of the Commission's IRP General Order, it is provided in the additional tables included in Appendix K
LEUG: Concerning Figure 20 on page 54, please provide the contribution to peak load by year, by customer class (Residential, Commercial, Small Industrial, Large Industrial, and Other) for each of the three Futures represented.	Please see the additional tables in Appendix K
LEUG: Concerning Figure 21 on page 55, please provide a tabulation showing by year, for each of the three Futures, the solar generation for Residential customer and for Commercial customers.	Please see Tables 19 and 20 in the ICF Potential Study Report and the explanation on page 54 of ELL's Draft IRP.
LEUG: Concerning Figure 22 on page 56, please provide a tabulation showing the amount of GWh by year for each of the three Futures.	Please see the additional tables included in Appendix K.
LEUG: Concerning Figure 23 on page 56, please provide the GWh by year for each of the three Futures.	Please see the additional tables included in Appendix K.
LEUG: Concerning Table 11 on page 59, please state whether the values shown in the table for each of the "hydrogen-capable" resources include all costs necessary to enable the indicated facilities to operate with a 30% mixture of hydrogen. If not, please provide the corresponding values with the various resources configured to burn a 30% hydrogen mixture.	The installed costs shown in Table 11 include inside the fence capital costs for the capability to burn 30% hydrogen for the applicable technologies. In order to facilitate burning 30% hydrogen, outside the fence costs (e.g., transportation and storage costs) may be necessary and would vary depending on location and type of resource.

LEUG: Concerning Table 12 on page 61, please provide the capital cost components of the solar, onshore wind and offshore wind capital costs shown in the Table. Please identify any cost categories not included, such as owners cost, owners engineer cost, allowance for funds used during construction, and other.	Capital costs for solar are sourced from IHS Markit. Components of this forecast include confidential information, and thus cannot be provided publicly. Owner's costs are included in the IHS Markit estimate. Allowance for funds used during construction ("AFUDC") is not represented in the IHS estimates. ELL includes adjustments for AFUDC, owner's contingency, transaction and oversight, and additional interconnection cost which were provided by internal resources based on previous experience in the industry. The resulting installed costs are summarized in the updated data assumptions presentation that was provided to the parties and which is available on the IRP website. Onshore wind costs are derived from five different third-party resources which include IHS, Lazard, NREL ATB, EPRI, and EIA with the cost learning curve following IHS' forecast. Not all sources provide specific cost category breakdowns and breakdowns that were provided to ELL by IHS cannot be provided publicly. Adjustments for transmission interconnection upgrades and AFUDC are not included in this estimate. Offshore wind costs are sourced from NREL's 2021 ATB, which includes construction financing cost and interconnection cost assumptions. Adjustments were made to convert the costs to nominal values assuming a 2% inflation factor.
LEUG: For Figure 27 on page 72, please provide, for each of the years 2023 through 2042, the numerical value and dollars per million Btu for each of the three cases presented in this figure.	Please see the additional tables included in Appendix K.
LEUG: Concerning Figure 29 on page 75, please provide, for each existing and planned solar resource, the MW solar capacity credit for each solar facility for each year shown.	Figure 29 is not intended to depict capacity credits for individual resources. It represents an assumption for how all solar resources may be credited in MISO as more solar resources enter the market.
LEUG: For each of Figures 30, 31, 32, 33, 34 and 35 on pages 77-79, please provide for each year the numerical value of each of the categories of capacity represented on the graphs.	Please see the additional tables included in Appendix K.
LEUG: Concerning Figure 36 on page 80, please provide, for each year and for each Future, the numerical value of the non-ELL LMP.	Please see the additional tables included in Appendix K.
LEUG: For Figure 37 on page 82, please provide, for each year, the numerical value for each of the two graphs plotted.	Please see the additional tables included in Appendix K.

LEUG: For Figure 38 on page 83, please provide the MW of capacity by year for each of the categories shown.	Please see the additional tables included in Appendix K.
LEUG: For Figure 39 on page 85, please provide the MW of capacity by year for each of the categories shown.	Please see the additional tables included in Appendix K.
LEUG: For Figure 40 on page 86, please provide the MW of capacity by year for each of the categories shown.	Please see the additional tables included in Appendix K.
LEUG: For Figure 43 on page 127, please provide, by year, the MW values of each component shown.	Please see the additional tables included in Appendix K.
LEUG: For Figure 44 on page 127, please provide, by year, the MW values of each component shown.	Please see the additional tables included in Appendix K.
LEUG: For Figure 45 on page 128, please provide, by year, the MW values of each component shown.	Please see the additional tables included in Appendix K.
LEUG: Please provide the detailed workpapers supporting the numbers in Table 30 on page 129.	Please see the additional tables included in Appendix K.
LEUG: Please provide the detailed workpapers supporting the numbers in Table 31 on page 130.	Please see the additional tables included in Appendix K.
LEUG: Please provide the detailed workpapers supporting the numbers in Table 32 on page 130.	Please see the additional tables included in Appendix K.
LEUG: Concerning Figure 46, please provide a workpaper showing the derivation of the costs shown for each of three portfolios in each of the three Futures.	Please see the additional tables included in Appendix K.
LEUG: Concerning Table 33 on page 131, please provide detailed workpapers supporting the derivation of each of the values shown in Table 33.	Please see the additional tables included in Appendix K.
Sierra Club: Please provide the underlying workpapers, including modeling inputs and outputs, for Figure 1 of the Draft Integrated Resource Plan, in their native format with all formulae intact.	This request is not within the scope of what is contemplated in the Commission's IRP General Order. Please see the additional tables included in Appendix K, for additional information on Figure 1.

Sierra Club: Please refer to pages 53 of the Draft Integrated Resource Plan. For each of the Company's "Future" forecasts a) Please provide the forward-going cost assumptions for each supply side resource alternative. Please provide both initial capital cost, ongoing capital, fixed and variable O&M, and fuel costs. b) Please provide cost assumptions, including the investment tax credit and/or production tax credit assumptions for solar, wind, and battery resources. c) Did Entergy (sic) incorporate the Inflation Reduction Act's cost reductions into its forecasted cost assumptions for solar, wind, and battery resources. If yes, please explain how those costs were incorporated. If not, why? No, this was not passed until Q3 2022. d) Did Entergy (sic) incorporate the effects of the Inflation Reduction Act into its forecasted energy market assumptions? If so, please explain and provide the forecasted assumptions. If not, why?	a) Capital and O&M cost inputs for each supply side alternative do not vary by market future (except Future 2 as noted below) and are summarized in the updated data assumptions presentation which was provided to the parties and is available on ELL's IRP website. b) See slides 35 and 38 of the updated data assumptions presentation for the ITC assumptions used for solar and hybrid resources in Futures 1 and 3. For onshore wind in Futures 1 and 3, PTCs were applied (60% for 2023 through 2025, 0% in 2026 and thereafter). For offshore wind in Futures 1 and 3, ITC was applied at 30% for 2023 through 2035 and 0% thereafter. c) The Inflation Reduction Act was passed in August of 2022, well after the IRP assumptions were finalized in accordance with the schedule outlined in the IRP General Order. In Future 2, the Company did model key provisions of the proposed Build Back Better (BBB) legislation, including production tax credits and investment tax credits for certain generation technologies. As discussed at the Stakeholder meeting, the modeled BBB assumptions are similar to those included in the IRA and thus Future 2 reasonably represents a future with tax credit provisions similar to the IRA. d) Please refer to the previous response.

Comments Regarding Load Assumptions:

Stakeholder Comment	ELL Response
LEUG: Please identify and provide the MW of Industrial load growth assumed in the Draft IRP for each year 2022-2042.	See Table 40 as well as the additional tables included in Appendix K.
LEUG: Please identify and provide the MW of Commercial load growth assumed in the Draft IRP for each year 2022-2042.	See Table 40 as well as the additional tables included in Appendix K.
LEUG: Please identify and provide the MW of Residential load growth assumed in the Draft IRP for each year 2022-2042.	See Table 40 as well as the additional tables (included in Appendix K.
LEUG: The Draft IRP at Appendix H, Table 35 indicates a peak load decrease of 213 MW for Entergy Louisiana over the previous six years 2015-2021 - - from 10,358 MW to 10,145 MW (summer peak). Please identify and provide the MW of Industrial load increase or decrease occurring in each such past year 2015 - 2021.	Please see footnote 51 on page 133 of ELL's Draft IRP.

Comments Regarding DSM:

Stakeholder Comment	ELL Response
LEUG: Please identify and explain the component items that comprise the 1,301 MW of Demand Response included in the Optimized Portfolio 1, including how much of each such component for each year of the plan is for: (a) Industrial load, (b) Commercial load, and (c) Residential load.	Refer to Table 15 and Figure 37 of ELL's Draft IRP and Figures 19 and 20 of ICF's DSM Potential Study Report. Please also see the additional tables included in Appendix K.
LEUG: For the Demand Response included in the Optimized Portfolio 1 for Industrial load, please identify and explain how many MW of each of the following is assumed for Industrial load for each year of the plan: (a) Solar Distributed Generation, (b) Energy Efficiency, (c) New Interruptible.	The industrial Demand Response included in Optimized Portfolio 1 includes no solar distributed generation, no energy efficiency, and is entirely from new or existing interruptible programs.

Comments Regarding Portfolios:

Stakeholder Comment	ELL Response
LEUG: Please identify and explain whether the Optimized Portfolio 1 identified and discussed in the Draft IRP at pages 82-84 has been selected by Entergy (sic) as the 2023 IRP Reference Resource Plan.	Yes, as stated on page 91 of ELL's Draft IRP, "ELL's Reference Resource Plan maintains the planning assumptions for existing units and continues adding renewable resources starting in 2025 consistent with Portfolio 1 though the exact amount of each type of renewable resource will be based on a market solicitation and may vary from the amounts identified in this analysis."
LEUG: Please identify and explain whether the 2,700 MW of solar resources identified in the Optimized Portfolio 1 includes: (a) 475 MW of solar resources approved by LPSC in Docket U-36190; (b) 600 MW potential renewable resources from 2021 RFP; (c) 1,500 MW potential renewable resources from 2022 RFP.	No, Portfolio 1 includes 2,700 MW of solar resources that are incremental to the planned resources referenced in this request. It should be noted that although the referenced RFPs have targeted capacity up to the amounts identified, it is not guaranteed that resources providing the amount of targeted capacity will be available or viable.
LEUG: Please identify and explain whether the following resources planned by Entergy (sic) are in addition to the 2,700 MW of solar resources identified in the Optimized Portfolio 1: (a) 475 MW of solar resources approved by LPSC in Docket U-36190; (b) 600 MW potential renewable resources from 2021 RFP; (c) 1,500 MW potential renewable resources from 2022 RFP.	Yes, Portfolio 1 includes 2,700 MW of solar resources incremental to the planned solar resources referenced in this request. It should be noted that although the referenced RFPs have targeted capacity up to the amounts identified, it is not guaranteed that resources providing the amount of targeted capacity will be available or viable.
LEUG: Please identify and explain whether Entergy (sic) plans to add offshore wind resources as part of the Optimized Portfolio 1, in addition to the indicated 6,600 MW of onshore wind resources?	Optimized Portfolio 1 does not include off-shore wind resources; however, ELL will continue to monitor off-shore wind technology, costs and viability.

LEUG: Please identify the CO_2 price assumption used in each year of the Optimized Portfolio 1	Please see the additional tables (Figure 26) included in Appendix K.

Other Comments:

Stakeholder Comment	**ELL Response**
LEUG: Please identify and explain what Entergy (sic) has in mind for "new opportunities for customer solutions that bring renewable generation to Louisiana" referenced in the IRP Action Plan.	ELL continues to evaluate opportunities to design and implement new options for our customers, such as the recently approved Rider GGO and Power Through programs. In evaluating potential future offerings of this nature, ELL continues to consider that customers are unique in their individual capacity and energy needs and that designing and implementing customer options that address those specific needs will be important to the success of future potential offerings
LEUG: Please identify and explain whether Entergy (sic) has conducted any reliability analysis for its system based on the Optimized Portfolio 1 and identified generation deactivations and contract expirations set forth in the Draft IRP, and if so provide copies.	Optimized Portfolio 1 meets the peak load plus reserve margin requirements for the reference load forecast based on the capacity credit assumptions for solar, wind, and battery resources as described in the IRP.
LEUG: Please identify and provide Entergy's (sic) capital investment plans toward providing EV Charging solutions in Louisiana.	This request is not within the scope of what is contemplated in the Commission's IRP General Order. ELL notes that a rulemaking is currently underway at the Commission related to EV charging.
LEUG: Please identify and provide Entergy's (sic) outlook for generation capacity surplus or deficit in Louisiana and MISO Zone 9 during the planning horizon.	Please see the additional tables (Figure 9) included in Appendix K.
LEUG: Please provide a copy of the Memorandum of Understanding ("MOU") with Diamond Offshore Wind that is mentioned on page 63.	This request is not within the scope of what is contemplated in the Commission's IRP General Order and seeks information that is HSPM.
LEUG: Please provide a copy of the joint development agreement with Mitsubishi Power that is mentioned on page 11.	This request is not within the scope of what is contemplated in the Commission's IRP General Order and seeks information that is HSPM.
LEUG: Please provide a copy of the Memorandum of Agreement with Holtec that is mentioned on page 12.	This request is not within the scope of what is contemplated in the Commission's IRP General Order and seeks information that is HSPM.
LEUG: Please provide the Loss of Load Probability ("LOLP"), Loss of Load Expectation ("LOLE") and any other indicators of reliability, for each year for each of the portfolios in Figures 38, 39 and 40. If no such measurements or estimates are available, please explain how it is possible to rationally compare the three resource expansion portfolios.	This request is not within the scope of what is contemplated in the Commission's IRP General Order and the Company did not conduct an analysis of LOLE or LOLP for each Portfolio. Each Optimized Portfolio meets the peak load plus reserve margin requirements for the load forecast assumed in the future for which it was designed based on the capacity credit assumptions for solar, wind, and battery resources as described in the IRP.

Sierra Club: Regarding the MISO seasonal construct: Please see page 33 of the IRP. a) Has the Company done an analysis (even if preliminary) of the impact of the MISO seasonal construct on its MISO capacity requirements? i. If so, please provide this analysis, and supporting workpapers (in Excel format, where available). ii. If not, please indicate when the Company plans on doing so. b) Has the Company done an analysis (even if preliminary) of the impact of the MISO seasonal construct on the UCAP values for solar, wind, or battery storage? i. If so, please provide this analysis, and supporting workpapers (in Excel format, where available). ii. If not, please indicate when the Company plans on doing so. c) Please provide the most recent forecast of the Company's peak demand for all four seasons. d) Please provide the most recent forecast of hourly load through the latest year available. e) Please provide all documents reviewed by the Company regarding the MISO seasonal capacity construct.	a) This request is not within the scope of what is contemplated in the Commission's IRP General Order. It should be noted that MISO is still seeking stakeholder feedback and has not implemented a seasonal construct for its capacity markets. To the extent the MISO does eventually finalize all aspects of the seasonal construct and implement such a construct, it would be relevant to examine in a future IRP cycle, provided the Company elects to remain in MISO. b) See the previous response. c) See the previous response. d) This request is not within the scope of what is contemplated in the Commission's IRP General Order. e) This request is not within the scope of what is contemplated in the Commission's IRP General Order.

Appendix C – ELL Responses to Stakeholder Comments Regarding ELL's 2023 Draft IRP Report

Comments Regarding Process:

Stakeholder Comment	ELL Response
AEMA: AEMA was not consulted prior to modeling and analysis were completed	ELL has followed the rules established in the LPSC's IRP General Order (Docket No. R-30021) and has provided opportunities for all stakeholders to provide feedback accordingly. Further, to the extent any stakeholder would like to recommend changes to the Commission's rules, ELL notes that the Commission has already opened a rulemaking to consider such changes (Docket No. R-36262).
AEMA: Incentives and programs in the Inflation Reduction Act should be fully imbedded in the calculations and modeling in the IRP Sierra Club: The Company should fully incorporate the Inflation Reduction Act in every modeling scenario SREA: SREA recommends that Entergy use its Business Plan 2023, and incorporate the Inflation Reduction Act, for all Portfolios and Futures, and re-run all the models Staff: Staff agrees that the subsidies which are reflected in current laws such as IRA should be part of the modeling assumptions for each applicable technology and not simply included in one future scenario and not the others. … Rather than only including the extended ITC and PTC assumptions in Future 2, these provisions should be included in the supply cost assumptions which feed all the scenarios. If ELL then wants to create a future in which the IRA is repealed, ELL must clearly specify that this assumption is a change from the current investment environment.	ELL has updated the total relevant supply cost calculation for all three portfolios to account for the provisions included in the Inflation Reduction Act. Please see the updates to Appendix I for a more detailed breakout of the total relevant supply cost calculations.
SREA: SREA recommends that Entergy provide its analysis regarding retirement assumptions and conduct sensitivities around earlier retirement of older, less efficient units Sierra Club: The Company should test earlier retirement of its units – especially with the pending Good Neighbor Plan and the Inflation Reduction Act	Please see ELL's Report on Assessment of the Economic Viability of Entergy Louisiana, LLC's Legacy Gas Generation. As is stated in Appendix A, the purpose of the IRP analysis is not to analyze or optimize near-term deactivation assumptions for individual units, but rather to identify long-term resource portfolios and strategies that are economic for ELL customers

Staff: ELL should report economic retirements of ELL resources that result from Aurora runs in ELLs future scenarios (not just the retirements that are assumed by ELL as inputs to the Aurora process)… ELL can presumably collect accurate data on the going-forward costs of its own units, and, if the energy market revenues projected by Aurora in the various future scenarios do not cover the total going-forward costs for several years, the unit would be flagged for retirement.	under a range of market conditions, as confirmed in the current IRP Rules. ELL also notes that the criteria proposed by Staff for designating existing units as slated for retirement or deactivation fails to consider ELL's obligation to provide reliable electric service to its customers. Staff's recommendation also fails to consider all of the required elements of deactivation analyses established in Commission Order R-34407. Staff's recommendation that the economics of a unit only be assessed based on projected energy market revenues ignores several other components that contribute to the economic value of a resource most notably capacity market value.
Sierra Club: Entergy should quantify and analyze the comparative public health impacts from air pollution, namely SO2, NOx, PM, and mercury emissions, of each of the portfolios it considers in its IRP and evaluate the public health cost that various air pollutants have on public health, especially in environmental justice communities In the selection of a preferred portfolio, Entergy can and should incorporate public health costs into its assessments	For more than a decade, ELL has been transforming its generation portfolio by deactivating older less-efficient and higher-emitting generating units and replacing them with modern and highly efficient gas-fired generating units. ELL's first solar resource came online in 2020. Since that time, ELL has received LPSC approval for a 475 MW solar portfolio, has sought certification for a 224 MW portfolio, and has two additional active and forthcoming solicitations seeking up to 1,500 MWs and 3,000 MWs of solar, respectively. ELL's generation portfolio also includes deactivation assumptions associated with approximately 2,400 MWs of gas-fired and coal-fired generating units by 2031; all of ELL's coal-fired generating units are expected to be deactivated by 2030. ELL's actions to date have resulted in significant reductions in emissions of SO_2, NOx, mercury, and PM (from 2017 to 2022, reductions of ~32%, ~23%, ~14% and ~7%, respectively), and the addition of solar to ELL's portfolio, coupled with the deactivation of approximately 2,400 MWs of gas-fired and coal-fired generating units by 2031, will undoubtedly further reduce these emissions. The IRP does not attempt to identify specific locations for the resource types included in the optimized portfolios for new resources. Such locational information would be needed in order to utilize appropriate geographical and meteorological data to conduct an air quality impact analysis for the optimized portfolios.
Sierra Club: Entergy should consider the environmental justice implications associated with its ultimate selection of its preferred portfolio	The IRP does not attempt to identify specific locations for the resource types included in the optimized portfolios. Locational information would

	be needed before environmental justice implications could be considered.
SREA: SREA states that Entergy should use MISO Futures and that it should create manual portfolios to address these futures. SREA recommends that Entergy run manual portfolios where the Company would achieve its own net zero carbon emission goals SREA also states that advanced technologies require manual portfolios, advanced modeling Staff: Neither should ELL create manual portfolios to respond the MISO MTEP Futures (and/or create a net-zero supply portfolio) as suggested by stakeholder. A portfolio should not be tailored to suit a particular future… a portfolio should be tested against a variety of futures.	ELL's IRP considers a range of possible future scenarios that are intended to identify and evaluate a range of portfolios and portfolio strategies to meet ELLs customers' needs across a range of possible future outcomes. Additionally, ELL did not see a need for manual portfolios for the IRP. Further ELL notes, Future 2, described in detail in Chapter 5, only allows for non-emitting resources to be selected through capacity expansion. The first resource selected in this portfolio is in 2025. In addition, all three portfolios are consistent with and make significant progress towards Entergy Corporation's announced sustainability and emissions reductions goals. As noted elsewhere in this report under Future 1's assumptions ELL has an emission rate of 142 lbs/MWh in 2042. In Future 3, 198 lbs/MWh in 2042. In Future 2, assuming no new fossil resources were added to the portfolio, ELL has an emission rate of 15 lbs/MWh in 2042. Future 1 saw a 78% reduction in carbon emission over the 20 years whereas Future 3 saw a 67% reduction. All 3 of ELL's Futures aligns with Entergy's net zero carbon goal. It should also be noted that Entergy Corporations net zero emissions goal (by 2050) extends beyond the planning horizon for this IRP and admittedly relies on necessary evolutions in technologies to make achievement of that goal technically feasible. As such, it is not presently possible to assemble a manual portfolio that achieves this goal from presently available, viable, commercially proven technologies.
Staff: ELL has overlooked an additional key and potentially game-changing uncertainty, and mistakenly modeled this key uncertainty as a "given" instead of recognizing it as a risk whose impact on the portfolios should be examined. This key uncertainty was… EPA's final revisions to the Cross-State Air Pollution Rule ("CSAPR")… Such an impactful uncertainty should be a feature of at least one of ELL's future scenarios.	ELL developed its portfolio analysis during 2022 and submitted its Draft IRP in October 2022. Staff's comments were received on March 8, 2023, the EPA's final CSAPR revisions were received by ELL on March 15, 2023. These CSAPR revisions are anticipated to be the subject of numerous legal challenges in various jurisdictions across the country and it is uncertain when these challenges will be resolved or what effect they may have on the final rule. Additionally, in May 2023, the U.S. Fifth Circuit Court of Appeals stayed EPA's Louisiana SIP Disapproval and as long as the stay remains in effect the FIP will not go into effect in Louisiana. ELL was required to submit its Final IRP in May 2023. Given this timing and the remaining uncertainty regarding the CSAPR it is not feasible to comply with Staff's recommendation

	during the present IRP cycle. As these uncertainties are resolved, ELL will consider the effects of any finalized rules in the next IRP cycle and other ongoing resource planning efforts.
AAE: IRP alignment with climate/greenhouse gas goals, including Entergy Corporation's own carbon emissions goals and the goals outlined by the Climate Initiatives Task Force Staff: Given Entergy's stated commitment to net zero carbon emissions by 2050, which is only eight years from the time frame contemplated in the IRP, ELL should report its current carbon footprint and the carbon footprint of each of the three portfolios in each of the three scenarios.	Please see the discussion in Chapter 5 in ELL's Final Report, as well as the above response to SREA's recommendation that ELL should develop manual portfolios that would achieve its own net zero carbon emissions goals, and also Staff's recommendation that ELL should not create a net zero supply portfolio. The work conducted through this process (including the results of all three portfolios) align with the Company's stated goals. Entergy Louisiana's blended emission rate in 2022 was approximately 744 lbs of CO_2 per MWh. Under Future 1's assumptions ELL has an emission rate of 142 lbs of CO_2 /MWh in 2042. In Future 3, 198 lbs of CO_2 /MWh in 2042. In Future 2, assuming no new fossil resources were added to the portfolio, ELL has an emission rate of 15 lbs of CO_2 /MWh in 2042.

Comments Regarding Inputs and Data Assumptions:

Stakeholder Comment	ELL Response
AEMA: EV resources should include participation – such as telematics-based programs – beyond smart chargers	ELL addressed this topic in its Draft IRP on PDF pages: 96 and 184. Furthermore, there are some vehicles today that do not allow for telematic access. While this is expected to change, many utilities are considering programs with both options - telematics and charger-control based, under the same umbrella. The same information is contained in this Final IRP Report.
AEMA: Residential battery storage should be more fully included in the IRP with Inflation Reduction Act incentives	Inflation Reduction Act incentives were not included in the residential battery storage demand response program, in-line with rest of the analysis/study. The Inflation Reduction Act had not been enacted at the time the DSM potential study was conducted. ELL anticipates incorporating IRA incentives into the DSM potential study conducted for the next IRP cycle.

AEMA: Energy storage benefits should include more value streams than simply demand reduction	ELL addressed this topic in its Draft IRP on PDF pages 96 and 202. As noted, demand charge reduction was modeled as the value stream for C&I battery storage both because of its national prevalence and its relevance to the particular rate structures for larger C&I customers in ELL territory. ELL's consultant, ICF felt that "any rules and valuation for that revenue stream would be too speculative to include in the DER potential study at this time." Though ELL does have hourly forecasted wholesale electricity prices, as AEMA states in its January 23, 2023, comments to the LPSC, that data is only one necessary component for modeling how behind-the-meter battery storage would realistically access wholesale revenue streams and the net costs and trade-offs in doing so. The same information is contained in this Final IRP Report.
AEMA: DR aggregation should be more fully considered for C&I and residential customers	ELL addressed this topic in its Draft IRP on PDF pages: 97 and 155. Furthermore, where the participation is restricted because of program structure or conditions, aggregation has been introduced to ensure that all participants have access to all programs. One example is the Interruptible program, that is introduced with a new mode of participation for smaller customers to remove the minimum demand eligibility criteria barrier. See the discussion of DR aggregation (for the C&I interruptible program) within the DR portion of ICF's Potential Study contained in Appendix L. The same information is contained in this Final IRP Report.
AEMA: DER applications should include aggregation of resources in preparation for Order 2222 implementation of MISO, regardless of the timeline	ELL addressed this topic in its Draft IRP on PDF pages 97 and 201. As noted, the uncertainty preventing ELL from including potential DER net revenues from FERC Order 2222 in its DER forecast is not only around timeline issues (Order 2222 implementation is not close to completion), but also around valuation. It is unknown what the Order 2222-related tariff specifics will be and how the markets for various DER technologies and customer classes will respond to the tariffs. DER aggregation is simply too speculative to include in this IRP process at this time. The same information is contained in this Final IRP Report.

AEMA: Additional DER technologies such as community solar and microgrids should be included in the IRP	ELL addressed this topic in its Draft IRP on PDF pages 97 and 193. AEMA states in its January 23, 2023, comments to the LPSC that “Community solar was not directly addressed in the response to the question and is another DER that should not be discounted.” However, ELL did address it specifically on PDF page 193 of the Draft IRP by stating, “ICF considered, but did not include, additional DER supply-side and control technologies such as community solar and microgrids in this potential study. Community solar was not included because ELL’s Optional Community Distributed Generation Rider did not have substantial enough capacity to be independently modeled. We did not model any additional community solar programs to avoid speculating on how utility programs and rate structures might change in the future.” AEMA’s January 2023 assertion on why community solar should have been forecasted by ELL (i.e., that the national community solar market is expected to rapidly grow and have significant capacity deployed nationally) is not germane to the reason that ELL previously provided for excluding community solar; ELL’s existing community solar offering did not have sufficient market uptake to warrant modeling in the 2023 Draft IRP. The same information is contained in this Final IRP Report. Regarding microgrids, AEMA’s January 2023 comments did not address ELL’s reasons for not including microgrids in the DER forecast; e.g., microgrids are highly idiosyncratic in configuration and operations, and it is extremely challenging to estimate if and how much incremental DER would be included in microgrids. Without addressing those considerable hurdles, it is infeasible to produce a methodical, long-term forecast of microgrid impacts on DER deployment. Further, because the market acceptance curves used in the ELL Draft IRP for solar and battery storage generally incorporate the reasons for DER deployment, inside or outside of microgrids, it is unclear if agreement with AEMA’s premise would even alter the forecasts.

AEMA: DERs should be addressed for resilience services which are considered a priority for ELL	ELL addressed this topic in its Draft IRP on PDF pages 97 and 192. ELL's goal in its Draft IRP forecasts for individual DER was to provide reasonable and well-explained forecasts, at a territory-wide level, for the volume and timing of future DER deployment based on information available at the time the forecast was prepared. As noted in ELL's Draft IRP, the market acceptance curves for solar and battery storage included resilience and environmental improvement along with other motivations for DER deployment. Those market acceptance curves produced deployment forecasts that were logical based on ELL DER market characteristics in the context of national DER experience. Further, the Draft IRP notes that, "The high scenarios in the DER modeling, in particular, can be thought to more highly value factors like environmental improvement and resilience because their market acceptance curves are heavily influenced by higher DER penetration markets with relatively low carbon grids and more pairings of solar and battery storage that offer resilience." Therefore, ELL believes that it appropriately included resilience, environmental, economic, and other potential motivations for customers to deploy DER. The same information is contained in this Final IRP Report. ELL agrees that the topic of electricity resilience against extreme weather is very important. ELL's proposed overall resilience approach ("Entergy Future Ready Resilience Plan") is described in LPSC Docket No. U-36625. There are two ongoing resiliency-related rulemakings in LPSC Docket Nos. R-36226 and R-36227.
AEMA: Additional transparency should be provided on components of and data used for Total Resource Cost Staff: Staff does not wish to determine which programs do or do not pass the TRC test (or the Total Relevant Supply Costs test) but agrees with AEMA that more explanation is useful, and there is no reason ELL should not provide these results.	The primary components for the TRC used in this study are three benefits and fours costs. The three benefits were the avoided energy costs for electricity, avoided demand costs for electricity, and the avoided energy cost for natural gas. The four costs were the incremental costs for measures, non-incentive costs for the programs, increased energy costs for electricity, and increased energy costs for natural gas.

AAE: Disaggregate and distinguish the cost effects between variable and non-variable aspects of the three futures described on page 74 of the Draft IRP (ref: cost associated with "baked-in assumptions" versus cost associated with resources selected in the IRP)	Peak load & energy growth, natural gas prices, MISO coal deactivations, MISO legacy gas deactivations, and carbon taxes affected the variable supply cost associated with the portfolios optimized for each future summarized in Appendix I. ITC/PTC assumptions were modeled by reducing the fixed cost inputs to capacity expansion associated with supply-side alternatives that were eligible for such tax credits. The DSM fixed costs associated with each future are summarized in Appendix I, and the variable effects of those programs are included in the variable supply cost line item in Appendix I for the respective portfolios.
AAE: Provide annual incremental, cumulative, and capacity savings in the load forecast assumed to result from organic efficiency adoption	Please see the additional tables (Table 40) in Appendix K.
AAE: Clarify whether only CCGTs were allowed to replace retirement of large legacy dispatchable gas units, and indicate more specifically whether solar was added to meet capacity needs from any unit deactivations or only certain types.	ELL did not limit its model in such a way so as to only allow CCGTs to replace large legacy dispatchable gas units. Solar was added to meet capacity needs from any unit deactivations.
AAE: Provide a more detailed explanation of DSM costs as referenced on page 129 of the Draft IRP, with an illustrative example. Is capacity value the only benefit considered in this calculation?	The "DSM Costs" referenced represent the total cost of the DSM programs for the relevant portfolio less the total capacity value provided by those programs. If the net cost is negative, that means the DSM programs represented a net reduction in cost based only on long-term capacity value. Energy-related benefits associated with DSM program load shapes are captured in the variable supply cost line item summarized in Appendix G.
AAE: Further explain the range of net rate impacts in Figure 47 on page 132 of the Draft IRP. What drives the higher and lower ends of the range, and what is the significance of (and factors used to determine) the "x" and "dot" for each scenario.	The ranges shown in Figure 47 of the Draft IRP represent the range of results as each portfolio Future is tested across each Scenario and is supported by Table 33. For each Scenario, the "x' represents the simple average estimated rate impact for all three Futures, and the "dot" represents the estimate rate impact for Future 1 in each Scenario. Please see Appendix K Table 33 for a more detailed breakout of the rate impact calculation.

LEUG: Lack of Industrial Customer Options, including: • Industrial customer market options • Enhanced CHP • A renewable generation option for industrial customers	Some of LEUG's requests go beyond the scope of this IRP process and in fact run contrary to a primary purpose of this process, maintaining a reliable electric system for Louisiana customers. The Commission is presently examining (or re-examining) some of the issues and ideas LEUG raises in several concurrent dockets, where ELL has provided extensive data and commentary. (For example, see LPSC Docket No. R-35426.) As discussed herein, the MISO capacity market is not designed to provide compensation for the full cost of generation resources. Rather, MISO relies on utilities within its market to provide the resources needed to ensure reliability through long-term resource planning under the regulation of state commissions. Therefore, allowing a select set of customers access to the pricing of the MISO market, rather than paying full retail rates, would allow those customers to avoid the full cost of the generation needed to reliably serve all Louisiana customers. The customers who are not offered that option would then be forced to pay for the total cost of generation or, alternatively, the utility would refuse to continue building generation needed for reliability and for which its customers would receive an undue share of the costs. The result of the latter option is a lack of local generation needed to serve customers. This IRP process is intended to achieve the opposite result. That being said, the Company is willing to explore tariff options that provide access to renewable resources and do not result in the cost shifting noted above. See, for example, the Company's proposal for a new green tariff (Rider GZ) recently submitted in Docket U-36697 and the Company's proposed expansion of Rider GGO submitted in Docket U-36685.
LEUG: Additional data should be included in the IRP report (10 years of historical data) • MWh of energy purchased from the market each year, over and above energy produced from owned and contracted resources; • MW of capacity deficit satisfied from market purchases each year (unforced capacity); • MW of baseload generation capacity relative to total owned generation capacity each year (unforced capacity); • MW of capacity imports and exports each year (unforced capacity); and • MWh of energy imports and exports each year.	This request is not within the scope of what is contemplated in the Commission's IRP General Order.

Sierra Club: The Company has still not addressed the costs of converting new gas units to hydrogen	The Company has provided a current best estimate of the costs to incorporate hydrogen optionality into new, future units. ELL's estimated costs for "Gas + Hydrogen" resources include costs to incorporated hydrogen-capability in natural gas units, but not costs required to burn hydrogen. At present, the complete costs and performance impacts of hydrogen firing capability are not fully vetted by the industry, and therefore have not been included in this analysis. As hydrogen technology continues to evolve, the Company may be able to assess these costs and performance impacts in a future IRP proceeding.
SREA: SREA states that natural gas accreditation should be improved Staff: The range across the [Natural Gas] futures is probably wide enough to produce useful tests of the economics of its three portfolios.	ELL develops natural gas price forecasts based on the consensus of independent, third-party consultant forecasts that consider fundamental factors that may affect the supply and demand for natural gas. In addition to using multiple consultant forecasts, a range of natural gas price forecasts are used in the evaluation to provide information on the sensitivity of results relative to natural gas price assumptions.
Staff: ELL should provide each [load] forecast numerically, at the same level of detail as the [load] forecast for Future 1.	Please see the additional tables (Tables 41 & 42) in Appendix K.
Staff: Staff recommends that ELL add additional "selected Technologies" to figure 25 of the Draft IRP Report. Specifically onshore wind costs including tax credits, offshore wind including tax credits, and solar including tax credits.	Please see the updated Figure 25 in the main body of this report.
Staff: The IRP rules specify including the cost of transmission in resource cost, but ELL did not provide data supporting its specific assumption for solar resources. Staff asked for evidence for this cost; also, it is not clear whether this cost is included in the analysis presented in the Draft IRP Report, and ELL should make this explicit. For wind resources, at the first stakeholder meeting, ELL did not indicate whether they included transmission costs for wind in the modeling; and this was also not made explicit in the Draft IRP Report. ELL needs to clarify its assumptions.	Following additional review, the $100/kW interconnection cost for solar was reduced to $55/kW, which assumes a switch yard, a small generator step-up transformer located next to the point of interconnection, and a tie-line to facilitate a 115kV, 138kV, or 230kV interconnection. This cost is included in the total relevant supply cost analysis presented in Appendix I of the Final IRP report. ELL included additional transmission cost in its Aurora modeling for offshore wind based on input from the Company's internal Transmission Planning organization. Onshore wind was modeled including transmission interconnection cost associated with project development as estimated by IHS Markit, but no additional transmission cost was developed or added.
Staff: ELL should provide the numerical output associated with Figure 20 of the Draft IRP, so that staff and stakeholders can refine the analysis shown in Figure 5 [of Staff's comments].	Please see the additional tables (Tables 41 & 42) in Appendix K.

Staff: Staff recommends that ELL re-examine its DR and EE assumptions and the role of energy prices in driving uptake of DR and EE.	It is not possible to reconduct the DSM potential study within the time frame provided for in the present IRP cycle.

Comments Requesting Additional Write Up in Final IRP Document:

Stakeholder Comment	ELL Response
AAE: Indicate why industrial customer efficiency savings potential is so low, despite the customer segment comprising such a large part of ELL's total energy consumption	ELL addressed this topic in its Draft IRP on PDF page 171. The low industrial potential is common across utilities as there is very limited adoption in the sector from EE programs. Industrial customers are simply less influenced by incentive-based programs and are thus often allowed to opt out of participation in such utility-provided EE programs, which is true for programs in Louisiana. Based on the ELL data, 50% of the industrial customer sales is from customers who have opted-out of their programs and is considered for this study. Furthermore, the lack of influence from incentive-based programs may be due to various factors including an increased likelihood of not needing incentives to undertake efficiency improvements, the unique nature of each individual customer making prescriptive programs less useful, limitations in the usefulness of custom programs since specialized knowledge is needed, and perceived or real risk of productivity losses from efficiency improvements. The same information is contained in this Final IRP Report.
AAE: The Alliance would like to see robust and equitable EE programs to reduce bills	See the discussion of DSM resources throughout this IRP Report and in ICF's DSM Potential Study contained in Appendix L.
AAE: Realistic resource costs, including gas, hydrogen, renewable, and battery storage assumptions	Within the context of the IRP and for the purposes of long-term resource planning, ELL finds that the costs assumed for "Gas and Hydrogen" and "Renewables and Energy Storage" resources are comparable to multiple industry resources, including NREL ATB. Gas and Hydrogen costs are derived from an engineering consultant with extensive industry experience, including development of natural gas with hydrogen capability plants. When comparing the total installed costs estimated by NREL ATB with ELL's assumption for solar, wind, and battery resources, the costs adopted by ELL is lower than or comparable to costs assumed by NREL ATB across all resources.
AAE: Alignment with other Entergy planning efforts, including transmission, distribution, resilience/reliability, retirements, and any others that the company undertakes outside of the IRP process	Please see the discussion of the coordination between these functions throughout this Final IRP Report.

Sierra Club: Entergy should consider including a summary of the findings from environmental evaluations in the next IRP and publishing copies of the full evaluation reports	The company will consider this feedback as it plans for the next IRP cycle.
Staff: ELL should state clearly that because transmission is a source of energy, but not necessarily capacity, the two are not perfect substitutes.	For the sake of clarification, transmission is neither a source of energy nor capacity. While transmission can facilitate the more efficient utilization and ultimate delivery of energy from generation resources, it is not a viable alternative to generation as transmission facilities do not possess the ability to generate electricity.
Staff: ELL should confirm that the MISO retirements are the result of going-in assumptions and, not the result of the Aurora optimization.	Confirmed. The non-Entergy MISO deactivations are the result of out of model assumptions either defined by the future (e.g. legacy gas & coal) or generic age-based deactivation assumptions.
Staff: ELL should clarify what it means when, referring to Table 19 in the report, ELL says that it summarizes key results for “each future.” It is not clear whether the results apply to every future. In other words, whether Future 1, 2 or 3 occurs, is the incremental installed capacity for a given portfolio the same?	The incremental installed capacity for a given portfolio differs for each optimized portfolio. For each optimized portfolio, the load requirement is reflective of the future for which the portfolio is optimized (e.g., Portfolio 1 is optimized in Future 1). Each portfolio is then simulated with the Aurora production cost model for each future.

Comments Regarding Portfolio Selections:

Stakeholder Comment	ELL Response
Sierra Club: Entergy continues to assume self-build only resources, but it is likely to procure PPAs SREA: SREA recommends that Entergy evaluate PPAs as a resource alternative Staff: One of the purposes of an IRP is to identify resources at the lowest cost. If ELL cannot avail itself of tax credits, it should allow independent developers to offer resources which reflect that tax advantage.	ELL's IRP seeks to identify the long-term resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Through this process ELL's analyses seeks to identify the types of supply side and demand side technologies that can meet its customers' needs for reliable service at a reasonable cost. Evaluation of commercial transaction structures, such as PPAs, is not relevant or appropriate for making these determinations. However, ELL further notes that resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures and that ELL does allow independent developers to offer resources under a PPA construct. Of the two certifications ELL has filed based on the completed 2020 and 2021 RFPs, ELL has sought to certify ~700 MWs from six new solar resources. Four of the six resources comprising more than 70% of the ~700 MWs of nameplate capacity are to be sourced from PPAs. Thus, despite the 2019 IRP not specifically evaluating commercial transaction structures, the resource procurements resulting from the 2019 IRP Action Plan have resulted in the addition, or potential addition, of several new PPAs for renewable resources. As such, stakeholders' concerns about customers being deprived of the potential benefits of a PPA structure are unfounded. It is unclear why Staff assumes that ELL can not avail itself of tax credits, however, the Company notes that assumptions regarding the cost benefits of tax credits are applied to the appropriate resource types regardless of commercial transaction structures. As such, the Company's analyses reflect these potential customer benefits.

SREA: SREA states that portfolio 2 was not fairly evaluated	Please refer to the discussion of Portfolio 2 in Chapters 5 and 6 for a thorough explanation of why ELL does not believe it is prudent or appropriate to utilize this Portfolio as a Reference Resource Plan. Please also refer to ELL's discussion throughout this document concerning the incorporation of the IRA into ELL's evaluation of all three Portfolios. It is important to keep in mind that IRP modeling is not intended to define a specific strategy for ELL to pursue onshore wind resources. The IRP analysis suggests that onshore wind is a cost-effective addition to ELL's portfolio when compared to other resource types according to expected cost and performance parameters for local deployment, especially in future 2 with higher federal incentives. Modeling an additional onshore wind resource to represent higher SPP capacity factors with higher (and more uncertain) transmission costs would not affect ELL's procurement strategy for onshore wind.
Staff: Staff wants to see ELL chose a portfolio (an action which is under the control of ELL) that is robust in a wide variety of future outcomes (which reflect potentially high-impact uncertainties).	Please see ELL's discussion of its rationale and criteria for selecting a Reference Resource Plan as described throughout this Report, particularly in Chapters 5 and 6.

Other Comments:

Stakeholder Comment	ELL Response
LEUG: LEUG estimates that its actual base rates could increase by 65% or more	ELL disagrees with LEUG's characterization of potential rate impact. LEUG's estimate (which does not appear to be supported by valid, fact-based analysis) not only overstates the fixed cost of resource additions but also fails to consider variable supply cost savings which are the primary source of value from renewable resources. LEUG's characterizations of the rate impacts of ELL's resource portfolios appear disingenuous at best, and intentionally misleading at worst. Please see Appendix I which supports the estimated rate impact, ranges from (¢1.06)/kWh to ¢0.00/kWh. It should be noted that neither LEUG's claim, nor Appendix I accounts for the effects of renewable tariff options, like Rider GGO or the recently proposed Rider GZ, which will offset the cost of renewable resources. As was demonstrated in Docket U-36190 and if fully subscribed, Rider GGO is projected to offset 80% of the 475 MW costs of the 2021 Solar Portfolio approved in that docket. ELL will continue to expand Rider GGO and propose other renewable tariffs such as the new Rider GZ, to achieve similar cost offsets for future solar portfolios, and provide customers with the option to participate directly in renewable resources – an option which LEUG's comments in this and other proceedings have requested. It should also be noted that neither LEUG's claim nor Appendix I account for additional AGM from load growth associated with new industrial sales from incremental electrification and load expansions.
LEUG: LEUG asserts that ELL's IRP lacks reliability analysis, service reliability metrics, and investment plans. SREA: SREA states that a system reliability assessment must be conducted Staff: Staff does not believe that ELL should be required to include and analysis of loss of load expectation ("LOLE") for each portfolio/scenario combination. While the IRP Rules contemplate reliability, ELL"s inclusion of a reserve margin, peak load projections, and capacity accreditation recognize reliability needs.	Section 6a of the IRP GO states that "The utility shall determine the reliability of its system…", and then goes onto state that "The LOLP result may be used as a target LOLP requirement in further analyses, or it may be converted to a target reserve margin requirement". As has been stated previously, ELL's IRP methodology solves for peak load plus reserve margin requirements for the reference load forecast based on the capacity credit assumptions described in the IRP. ELL's "investment plans" relative to its preferred portfolio is summarized by way of TRSC located in Appendix I of this report.

LEUG: Referring to Information Provided by Entergy Subsequent to Technical Conference: Summary information alone is not necessarily sufficient to understand how Entergy came up with its numbers and whether or not such numbers and representations submitted by Entergy therefrom are reasonable or appropriate (ref: detailed workpapers)	ELL has posted its publicly available initial IRP data assumptions, responses to stakeholder questions, and supplemental data assumptions on its public website at https://www.entergy-louisiana.com/irp/2023_irp/. ELL does not intend to make native files publicly available. ELL's efforts in this regard have gone above and beyond the requirements imposed by the IRP GO.
LEUG: Entergy should comply with IRP rule regarding transmission system analysis SREA: SREA states that transmission analysis is required but absent • Notes that IRP did not include sufficient information pertaining to the Protect Louisiana Plan • Notes that IRP does not consider transmission as an alternative to generation Staff: The IRP Rule provides that "At times, there may be large transmission projects that could provide access to economic generation resources, and it may be desirable to treat those projects as separate resource options in the optimization process." In other state, IRPs include scenarios with and without major transmission projects, because the existence of a new transmission line (even if it is not a perfect substitute for generation) could change the optimal portfolio of generation resources. A good example of this is the 2021 IRP by Idaho Power.	Transmission is not a viable alternative to generation. Transmission facilities do not possess the ability to generate electricity or provide capacity that will result in Zonal Resource Credits in the MISO Planning Resource Auction. The analysis performed for the resource portfolio design included in the IRP document is based on evaluating ELL's projected capacity and energy needs. While transmission may impact the locations in which generation can be sited, it is incapable of reducing the need for generation capacity. Other analyses which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning, and may apply the transmission topology in the AURORA Nodal Model construct, including approved MISO MTEP projects Please also refer to ELL's discussion of the transmission planning process conducted in coordination with MISO in the Transmission Planning section of Chapter 3 within this Final IRP Report. Please see Appendix F – MISO MTEP Submissions for a description of the transmission projects approved or submitted through MISO's MTEP process. ELL's discussion of the transmission planning process conducted in coordination with MISO, in Chapter 3 as referenced above, is also important to consider in light of Staff's recommendation that ELL should consider scenarios with and without a "major transmission project." In light of the transmission planning processes described therein, it is unclear what value the sensitivity analysis described by Staff could add to the IRP process. ELL notes that the utility referenced in Staff's comments (Idaho Power) does not belong to or coordinate transmission planning in conjunction with an RTO. In any event, making significant modifications to the future scenarios considered for the current IRP would not be possible on the timeline established by the IRP GO. The Company's proposal in Docket U-36625 is being fully considered in that docket, in which SREA intervened on 1/17/2023, and does not impact the analyses conducted by the Company in the preceding.

LEUG: Entergy should comply with IRP rule regarding RMR units and potential solutions	"Reliability Must Run" is a legacy term that predates ELL's participation in MISO. In MISO, out-of-market unit commitment for reliability reasons is classified based on the reasons for such commitment – e.g., Voltage and Local Reliability. ELL interprets this comment and its reference to "Reliability Must Run units" (as well as the reference to this term in the IRP General Order, which order also predates ELL's participation in MISO) as addressing an out-of-market unit commitment that may occur for a variety of reliability-related reasons. The Amite South, DSG and WOTAB operating guides each provide a list of generation units which may be committed for thermal and/or voltage support (which is comparable to a list of potential "RMR" units in the areas served by ELL). The constraints described in these operating guides are the primary drivers of these "RMR" commitments. RMR commitment procedures are dependent on regional characteristics which change over time. These characteristics include (without limitation) load growth, resource start up times, and resource availability. There are several transmission projects in the MISO planning processes that are expected to help mitigate the constraints listed in the Amite South and DSG Operating Procedures.
LEUG: IRP modeling should not be used as a basis to circumvent analysis of resources available in the market	The LPSC Corrected General Order for Docket No. R-30021: In Re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities ("IRP Docket") states beginning on page 2, "The goal of the IRP is to develop a defined resource plan, and the Action Plan is intended to specify implementing actions that the utility should take, however Staff recognizes that these rules are not intended to replace or modify the normal docketed resource certification process, and a statement to this effect is included in the Action Plan section." ELL utilizes a separate docketed resource certification process, in accordance with the requirements of the MBM Order, for certification of the resources identified in the Action Plan that ELL chooses to pursue.
LEUG: IRP process is not a substitute for LPSC certification process and procedure	ELL has not proposed that the IRP be utilized as a substitute for the current Commission certification requirements outlined in the 1983 General Order or the Market Based Mechanisms Order.

Sierra Club: Entergy should invest in additional renewable energy and storage resources	ELL's Reference Resource Plan includes 9,750 MWs of renewable energy and storage resources in 2042. However, as is stated in response to an earlier comment, "The goal of the IRP is to develop a defined resource plan, and the Action Plan is intended to specify implementing actions that the utility should take, however Staff recognizes that these rules are not intended to replace or modify the normal docketed resource certification process, and a statement to this effect is included in the Action Plan section." ELL utilizes a separate docketed resource certification process, in accordance with the requirements of the MBM Order, for certification of the resources identified in the Action Plan that ELL chooses to pursue. That said, ELL 1) has received certification to add 475 MWs of new solar projects to its portfolio, 2) has filed an application for the certification of an additional 224 MWs of solar projects, 3) has an active RFP seeking up to an additional 1,500 MWs of solar projects, which RFP allows for developers to bid both wind and battery storage resources, and 4) has filed an application for the pre-certification of up to 3,000 MWs of solar resources.
Sierra Club: Entergy should take advantage of securitization when retiring fossil units	This request is not within the scope of what is contemplated in the Commission's IRP General Order.
SREA: SREA states that Entergy's revenue requirements, within the IRP, are missing components	Please see the backup data for Tables 30, 31 and 32 in Appendix K for the annual breakdown of TRSC components.
SREA: SREA states that portfolios, preferred resource plan do not significantly inform action plan, that Entergy's action plan is inadequate, and that the Action Plan should explicitly state when RFPs will be released	The IRP's future resource portfolios are developed consistent with the Commission's Integrated Resource Planning General Order but do not represent planning decisions by ELL. The Company's planning decisions, specifically as they relate to the development of an RFP, are better informed in the time period leading up to the issuance of an RFP, rather than in the context of its IRP. For this reason, and others, ELL intends to continue to issue sizeable and frequent renewable RFPs, and ultimately work toward its 2030 and 2050 sustainability goals, and the specific scope of future RFPs will be developed in the time period leading up to the issuance of an RFP.

Appendix D – ELL Portfolio of Owned Resources

Table 21: ELL Portfolio of Owned Resources

Plant	Unit	ELL Ownership Share of GVTC [MW]	Fuel	Location	Operation Date
Acadia	2	526	Natural Gas	Acadia, LA	2002
ANO	1	22	Nuclear	Pope, AR	1974
ANO	2	26	Nuclear	Pope, AR	1980
Big Cajun 2	3	135	Coal	Pointe Coupee, LA	1983
Calcasieu	1	142	Natural Gas	Calcasieu, LA	2000
Calcasieu	2	159	Natural Gas	Calcasieu, LA	2001
Grand Gulf	-	203	Nuclear	Claiborne, MS	1985
Independence	1	7	Coal	Independence, AR	1983
J. Wayne Leonard Power Station	-	912	Natural Gas	Montz, LA	2019
Lake Charles Power Station	-	913	Natural Gas	Westlake, LA	2020
Little Gypsy	2	405	Natural Gas	Saint Charles, LA	1970
Little Gypsy	3	504	Natural Gas	Saint Charles, LA	1971
Ninemile	4	724	Natural Gas	Jefferson, LA	1971
Ninemile	5	728	Natural Gas	Jefferson, LA	1973
Ninemile	6	438	Natural Gas	Jefferson, LA	2014
Ouachita	3	241	Natural Gas	Ouachita, LA	2002
Perryville	1	355	Natural Gas	Ouachita, LA	2002
Perryville	2	101	Natural Gas	Ouachita, LA	2001
Riverbend 30	-	191	Nuclear	West Feliciana, LA	1986
Riverbend 70	-	389	Nuclear	West Feliciana, LA	1986
Roy Nelson	6	211	Coal	Calcasieu, LA	1982
Union PB	3	505	Natural Gas	Union, AR	2003
Union PB	4	505	Natural Gas	Union, AR	2003
Waterford	2	415	Natural Gas	Saint Charles, LA	1975
Waterford	3	1,155	Nuclear	Saint Charles, LA	1975
Waterford	4	32	Oil	Saint Charles, LA	2009
White Bluff	1	13	Coal	Jefferson, AR	1980
White Bluff	2	12	Coal	Jefferson, AR	1981
Washington Parish Energy Center	-	370	Natural Gas	Bogalusa, LA	2020
LMR (Load Modifying Resource)	-	301	N/A	-	-
Total	-	10,640			

Appendix E – Existing Resource Discussion

Acadia 2:

Acadia 2 is a 2X1 combined cycle gas turbine natural gas-fired facility located near Eunice, LA. The facility entered commercial operation in 2002 and was acquired by ELL in 2011. It is one of two CCGTs located onsite, with the other facility (Acadia 1) being owned by Cleco Power. ELL also owns 50% of the Common Facilities on site. Cleco Power operates and maintains Acadia 2. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The facility is expected to experience good reliability and availability for the foreseeable future.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Big Cajun 2, Unit 3:

Big Cajun II Unit 3 is a 588 MW coal unit, located on the Big Cajun II facility, in New Roads, Louisiana. The facility entered commercial operation in April of 1983. NRG transferred ownership of the facility to Cleco in February of 2019. There are 3 units located on the Big Cajun II facility, 2 coal and 1 natural gas; Entergy Louisiana owns a non-controlling interest of 24.15% of Unit 3 and is responsible for associated costs. Entergy Louisiana is also responsible for 8.05% of the common facility costs.

Calcasieu 1:

Calcasieu 1 is a simple-cycle gas-fired generating unit located near the city of Sulphur, LA. The unit entered commercial operation in 2000 and was acquired by ELL in 2008. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit should continue to experience good reliability and availability for the foreseeable future.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Calcasieu 2:

Calcasieu 2 is a simple-cycle gas-fired generating unit located near the city of Sulphur, LA. The unit entered commercial operation in 2001 and was acquired by ELL in 2008. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit should continue to experience good reliability and availability for the foreseeable future.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

J. Wayne Leonard Power Station:

The J. Wayne Leonard Power Station is a 2X1 combined cycle gas turbine facility located near Montz, LA. The facility entered commercial operation in 2019 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Lake Charles Power Station:

The Lake Charles Power Station is a 2X1 combined cycle gas turbine facility located near Westlake, LA. The facility entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Little Gypsy 2:

Little Gypsy 2 is a steam turbine generating unit located near Montz, LA. The unit entered commercial operation in 1966. The unit is in fair condition, having been maintained over its long life in accordance with Good Utility Practice. At 54 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

[redacted]

[redacted]

Little Gypsy 3:

Little Gypsy 3 is a steam turbine generating unit located near Montz, LA. The unit entered commercial operation in 1969. The unit is in generally good condition, having been maintained over time in accordance with Good Utility Practice. At 50 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ninemile 4:

Ninemile 4 is a steam turbine generating unit located near Westwego, LA. The unit entered commercial operation in 1971. The unit is in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of a significant maintenance/repair program in recent years.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

[redacted]

Ninemile 5:

Ninemile 5 is a steam turbine generating unit located near Westwego, LA. The unit entered commercial operation in 1973. The unit is in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of a significant maintenance / repair program in recent years.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ninemile 6:

Ninemile 6 is a 2X1 combined cycle gas turbine dual fueled (natural gas and liquid fuel) facility located near Westwego, LA. The facility entered commercial operation in 2014 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

[redacted]

[redacted]

Nelson 6:

Nelson 6 is a coal fired generating unit located near Westlake, LA. The unit entered commercial operation in 1982. The unit is jointly owned by four co-owners. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ouachita 3:

Ouachita 3 is one of three 1X1 combined cycle gas turbine natural gas-fired facilities located on a site near Sterlington, LA. The facility entered commercial operation in 2002 and was acquired by Entergy in 2008. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

[redacted]

Perryville 1:

Perryville 1 is a 2X1 combined cycle gas turbine natural gas-fired facility located near Sterlington, LA. The facility entered commercial operation in 2002 and was acquired by ELL in 2005. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Perryville 2:

Perryville 2 is a simple-cycle gas-fired generating unit located near Sterlington, LA. The unit entered commercial operation in 2001 and was acquired by ELL in 2005. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Perryville BESS:

The Perryville Battery Energy Storage Station is a 7.4 MW / 7.4 MWh energy storage station near Sterlington, LA. This BESS is paired with Perryville 2 as the regional blackstart resource for ELL. When commissioned it was the first GE 7FA.03 BESS blackstart resource in the industry.

River Bend:

River Bend Station is a nuclear facility, located in St. Francisville, LA. The station sits on 3,300 acres in West Feliciana Parish, approximately 30 miles from Baton Rouge. Since June 1986, River Bend has safely and efficiently provided clean, reliable and sustainable nuclear energy. In

2018, the U.S. Nuclear Regulatory Commission granted a federal 20-year license renewal, enabling the plant to continue operating through 2045.

River Bend has one boiling water reactor with about 800 employees providing nearly 1,000 megawatts of capacity towards meeting ELL's planning reserve margin requirement, which is approximately 10 percent of ELL's needs. River Bend began a scheduled refueling and maintenance outage in February 2023.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Sterlington 7A:

Sterlington 7A was deactivated in 2022.

Union 3:

Union 3 is one of four 2X1 natural gas-fired combined cycle gas turbines located on a plant site near El Dorado, AR. The facility entered commercial operation in 2003 and was acquired by ELL in 2016. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

[redacted]

Union 4:

Union 4 is one of four 2X1 natural gas-fired combined cycle gas turbines located on a plant site near El Dorado, AR. The facility entered commercial operation in 2003 and was acquired by ELL in 2016. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Washington Parish Energy Center 1:

Washington Parish Energy Center 1 is one of two simple-cycle gas fired generating units located in Bogalusa, LA. The unit entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Washington Parish Energy Center 2:

Washington Parish Energy Center 2 is one of two simple-cycle gas fired generating units located in Bogalusa, LA. The unit entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

- Silencer Replacement. Completed 2021

Waterford 1:

Waterford was deactivated in 2021.

Waterford 2:

Waterford 2 is a steam turbine generating unit located near Killona, LA. The unit entered commercial operation in 1975. The unit is in generally good condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of certain notable repairs in recent years, as detailed below. At 47 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Waterford 3:

Waterford 3 is a nuclear facility, located on the west bank of the Mississippi River in St. Charles Parish, near the town of Taft, LA, located approximately 25 miles east-southeast from New Orleans. It consists of over 3,000 acres of flat land extending from the Mississippi River to the St. Charles Drainage Canal. The Waterford 3 Facility Operating License was issued on March 16, 1985, and has since safely and efficiently provided clean, reliable, and sustainable carbon free nuclear energy.

Waterford 3 is a pressurized water reactor designed by Combustion Engineering Incorporated with approximately 700 employees. The station generates approximately 1,200 megawatts of capacity towards meeting ELL's planning reserve margin requirement, which is approximately 11.8% of ELL's needs. [redacted]

Major maintenance activities undertaken at the unit in 2022 to improve unit reliability include:

[redacted]

Waterford 4:

Waterford 4 is a simple-cycle, diesel-fired generating unit located near Killona, LA. The unit was originally commissioned in the northeastern United States in the early 1990s. It was later acquired by ELL and relocated to Louisiana in 2009. The unit entered commercial operation for ELL in 2009, following an extensive refurbishment. In addition to its role as a quick start peaking resource, the unit currently serves as a regional blackstart resource for ELL.

The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Appendix F - MISO MTEP Submissions

Table 22: ELL Projects Approved in Appendix A of MTEP16

Project Driver	Project Name	Current Projected ISD
Load Growth	Thompson Road 230 kV: Construct New Substation	5/1/2023
Load Growth	Big Lake 230 kV: Construct New Substation	5/30/2023
Baseline Reliability	East Broad to Ford 69 kV line: Reconductor line	6/30/2023
Load Growth	Lake Providence 115 kV: New station	6/1/2024

Table 23:ELL Projects Approved in Appendix A of MTEP17

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Avenue C to Paris Tap 115 kV: Reconductor Line	12/30/2022
Other Reliability	Pecue 230 kV: Install transmission breakers	12/31/2022
Baseline Reliability	Jennings to Lawtag 69 kV L-13/L-19 and L-14 Reconductor	2/28/2023
Baseline Reliability	Five Points to Line 281 Tap to Line 247 Tap - Upgrade 69 kV line	3/30/2023
Baseline Reliability	Mud Lake to Big Lake 230 kV: New Line	5/30/2023
Baseline Reliability	Gypsy to Claytonia 115 kV: Reconductor Line	6/1/2024
Asset Management	Culicchia 230 kV: New Substation	12/1/2025

Table 24: ELL Projects Approved as Appendix A of MTEP18

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Mossville to Lockmoor 69 kV: Rebuild/Reconductor Line	12/31/2022
Load Growth	Goosport 138 kV: Convert Sub from 69 kV	6/1/2026

Table 25: ELL Projects Approved as Appendix A of MTEP19

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Sellers Leblanc Project (SLP): New Conrad to Sellers Road 138kV line	12/1/2022
Generation Interconnection	Galion 115 kV: Install Transmission Line Bay and Breakers (J544 Interconnection)	12/15/2022
Baseline Reliability	Jefferson Parish Area Reliability Plan Phase 2: Munster 230 kV	6/1/2023
Other Reliability	Ninemile S2015: Close Normally Open Breaker	6/1/2023
Baseline Reliability	Coly to DEMCO Coly 69 kV Upgrades	12/31/2023
Other Reliability	Ponchatoula 230 kV: Add Breakers and Transfer Bus	12/31/2024

Table 26:ELL Projects Approved as Appendix A of MTEP20

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Nelson 138 kV Substation: Install Breakers	12/31/2022
Generator Interconnection	J697/J1436 Interconnection: Expand Oak Ridge 115 kV Substation	7/1/2023
Generator Interconnection	J909 Interconnection: Amite 115kV Substation	10/15/2023
Generator Interconnection	J639 Interconnection: Construct Bueche 230kV Substation	12/31/2023

Table 27: ELL Projects Approved as Appendix A of MTEP21

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Frisco to Tezcuco 230 kV: Upgrade Circuit 1 and 2	12/30/2022
Baseline Reliability	Lake Arthur 69 kV Switch Upgrade	12/31/2022
Asset Management	2022 ELL Asset Renewal Program	12/31/2022
Baseline Reliability	Nelson 230 kV SPOF	12/1/2023
Generator Interconnection	J1158 Generator Interconnection at Vacherie 230 kV	7/1/2024
Baseline Reliability	Nelson 138 kV SPOF	1/1/2026
Load Growth	Northline 230 kV: New Substation	6/1/2026

Table 28:ELL Projects Submitted as Target Appendix A in MTEP22

Project Driver	Project Name	Current Projected ISD
Generator Interconnection	J1368/J1372 Interconnection: Ventress 230 kV Station	4/21/2023
Baseline Reliability	Drusilla to Jefferson 69 kV: Upgrade Switches	6/1/2023
Asset Management	Hartburg to Rhodes 500 kV River Crossing Tower Replacement	8/31/2023
Asset Management	2023 ELL Asset Renewal Program	12/31/2023
Network Upgrade	MPFCA J1281, J1294, J1458 Adams Creek 230 kV and Bogalusa 500-230 kV Upgrades	4/4/2024
Baseline Reliability	Dowmeter to Tiger 230 kV Re-termination	6/1/2024
Generator Interconnection	J1246 Bayou Labutte 500 kV Interconnection	6/1/2024
Network Upgrade	Point Pleasant 230 kV Breaker upgrades (tied to J1246)	4/9/2025
Generator Interconnection	J1219/J1257 Hickory 115 kV	9/24/2024
Generator Interconnection	Rilla 115 kV: Expand Station (J1239)	10/15/2024
Other Reliability	Kaiser 230-115 kV Autotransformer	12/1/2024
Baseline Reliability	Richard 500-138 kV AT1 Relay Improvement SPOF	12/31/2024
Load Growth	Calhoun 230 kV: Construct New Substation	6/1/2026

Table 29:ELL Projects Submitted as Target Appendix A in MTEP23

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Dixie Baker to Baker 69 kV: Reconductor Line	6/1/2026
Baseline Reliability	Delmont to Hazel 230 kV: Upgrade Line	6/1/2026
Baseline Reliability	Delhi - Tallulah 115 kV Rebuild	12/1/2026
Baseline Reliability	Winnsboro to Gilbert 115 kV Rebuild	12/1/2026
Baseline Reliability	Gilbert to Wisner 115 kV Rebuild	12/1/2026
Baseline Reliability	Dixie Baker to Zachary 69 kV: Upgrade Line	6/1/2027
Asset Management	McKnight 500 kV GIS Replacement	TBD
Asset Management	Webre 500 kV GIS Replacement	TBD
Asset Management	Holiday to Lafayette 69 kV: Reterminate into Elks	TBD
Asset Management	Barnett Oil Mill 69 kV Relocation	TBD
Baseline Reliability	Mossville 69 kV Upgrade Breaker 17955	TBD
Asset Management	2024 ELL Asset Renewal Program	TBD
Other Reliability	DSG Reliability & Resiliency Upgrade	TBD
Baseline Reliability	Willow Glen 138 kV Reconnect Bus	TBD
Baseline Reliability	Port Hudson - Jackson 69 kV: Switch Upgrades	TBD
Baseline Reliability	Blount to Devil Swamp New 69 kV line	TBD
Baseline Reliability	Tiger 69 kV: Bus Upgrades	TBD
Asset Management	MTEP23 ELL Capacitor Bank Retirements	TBD
Other Reliability	Amite South Reliability Project - Phase 1	TBD
Other Reliability	Amite South Reliability Project - Phase 2	TBD
Other Reliability	Amite South Reliability Project - Phase 3	TBD
Asset Management	Coly 500 kV GIS Replacement	TBD
Asset Management	Jaguar 230 kV GIS Replacement	TBD

Appendix G – Scope of Aurora Market Model

The shaded areas shown on the map below are modeled in Aurora. These areas include MISO-South, and the remainder of MISO (MISO-Central, and MISO-North).

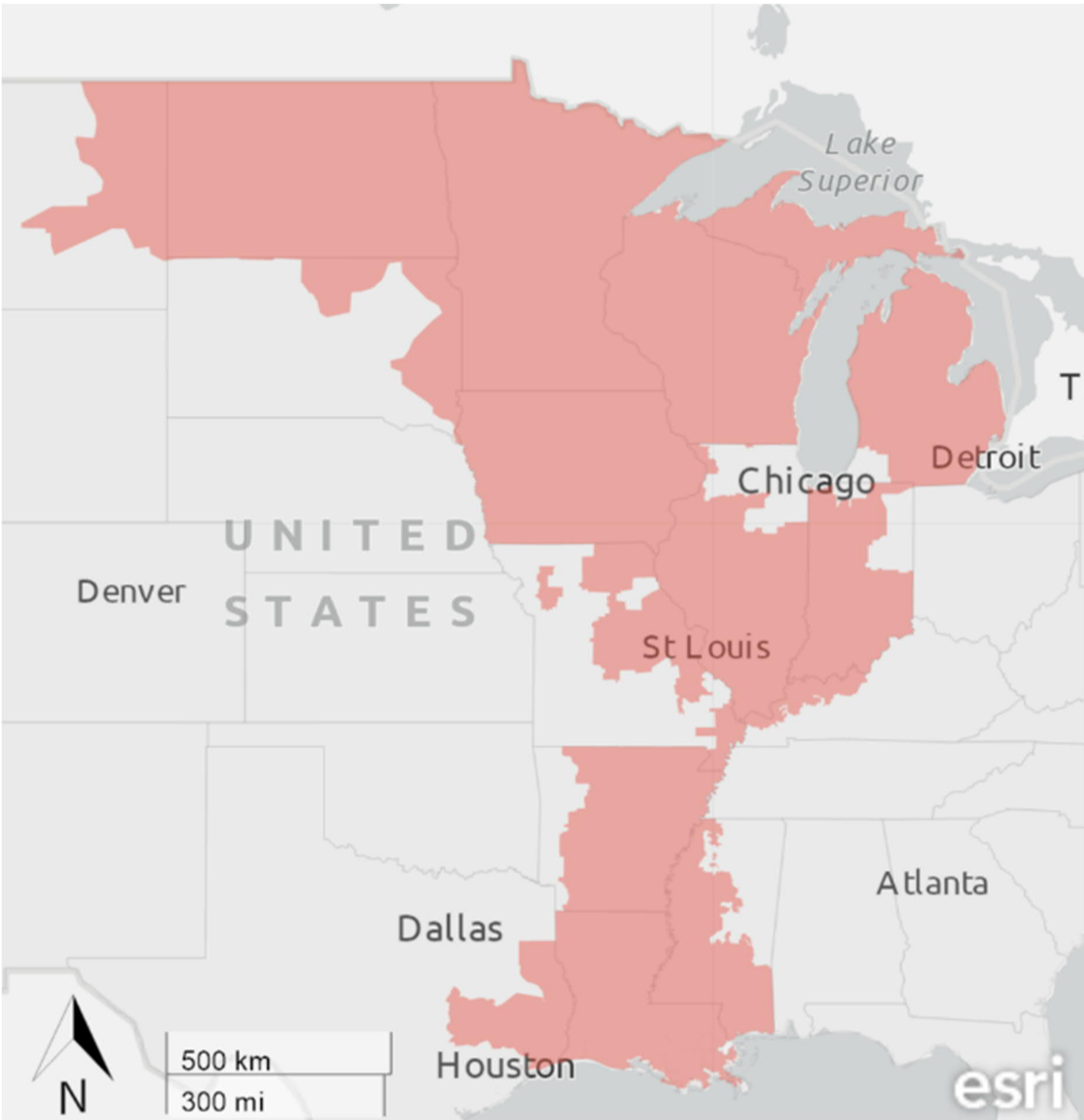

Figure 42: Map of MISO North and South

Appendix H – Portfolio Capacity Mix Figures

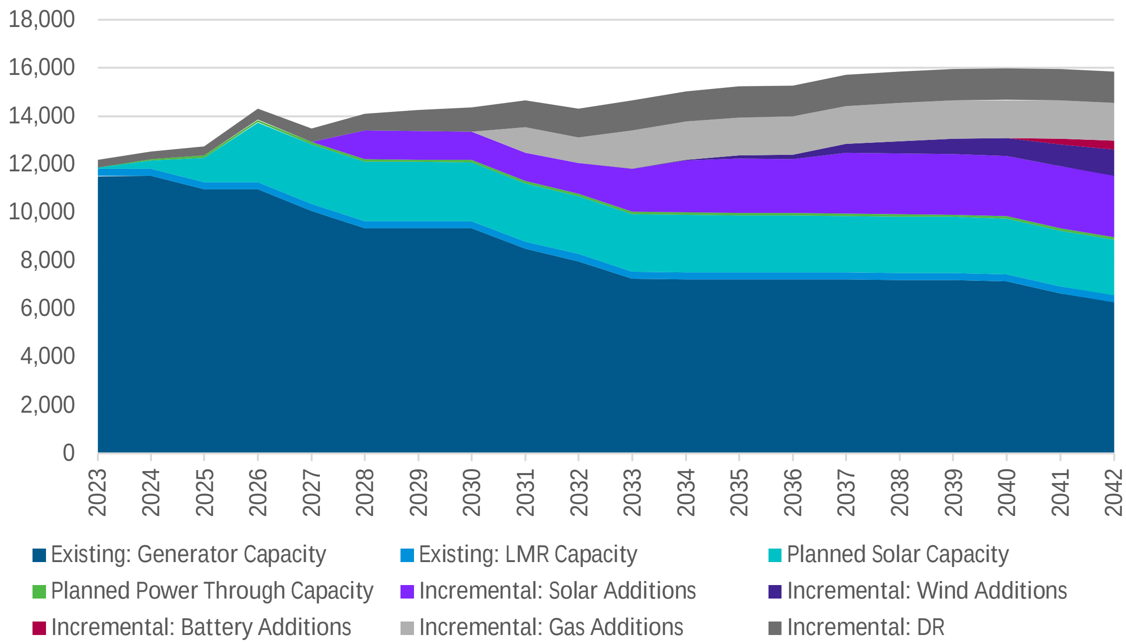

Figure 43: Portfolio 1 ELL Capacity Mix (Installed MW)

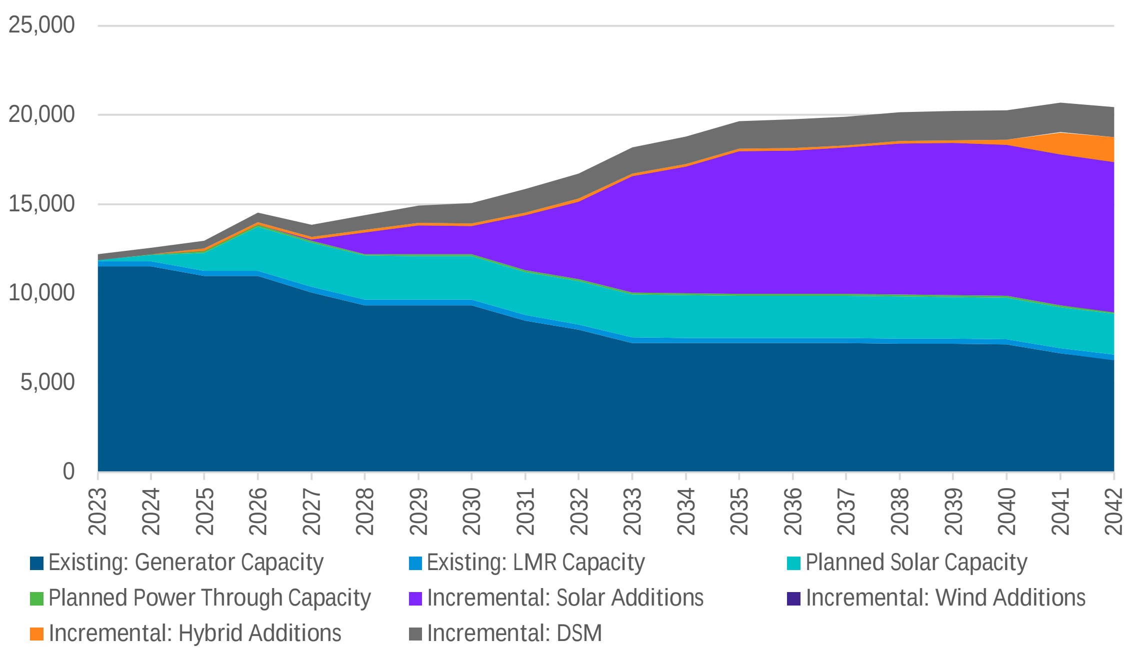

Figure 44: Portfolio 2 ELL Capacity Mix (Installed MW)

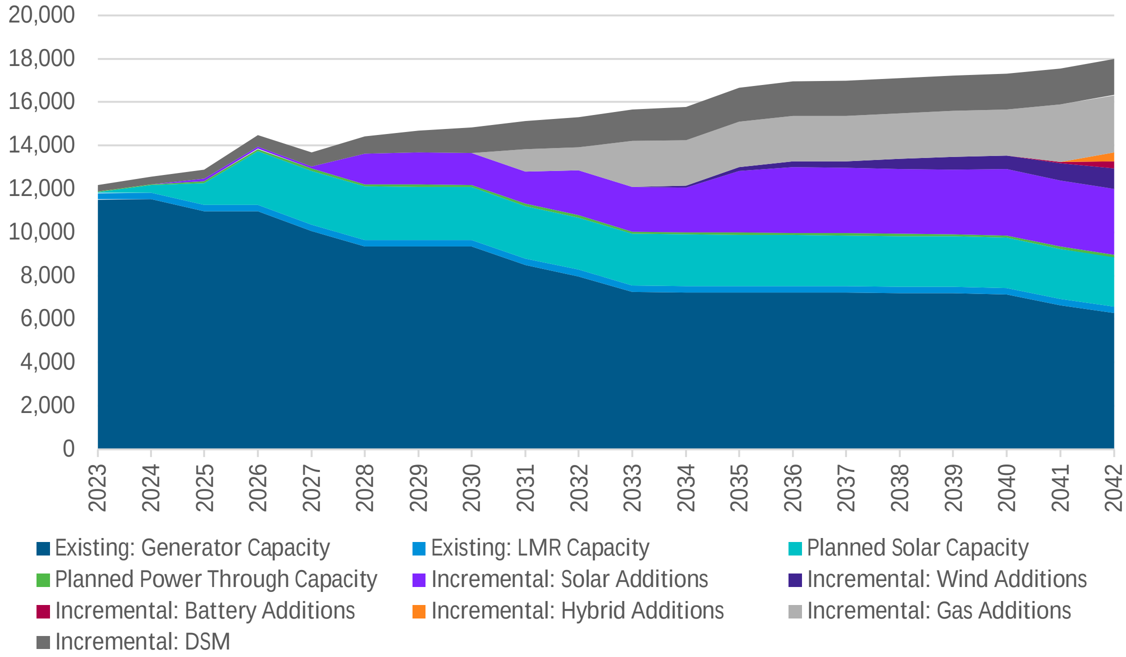

Figure 45: Portfolio 3 ELL Capacity Mix (Installed MW)

Appendix I – Total Relevant Supply Cost Analysis Results

Total Relevant Supply Cost Analysis Results

The Total Relevant Supply Cost ("TRSC") for each portfolio was calculated for the future for which it was developed. The total relevant supply cost is calculated using:

Variable Supply Cost - The variable output from the Aurora model for each portfolio in each of the futures, which includes fuel costs, variable O&M costs, emission costs, startup costs, energy revenue, make-whole payments, and uplift charges.

Levelized Real Non-Fuel Fixed Costs - Return of and on capital investment, fixed O&M, tax credits attributable to the IRA, and property tax for the incremental resource additions in each portfolio, calculated on a levelized real basis.

DSM Costs - Costs associated with DSM programs less capacity value associated with the program.

Capacity Purchases/(Sales) - The capacity surplus (or deficit) in each portfolio multiplied by the assumed capacity value.

The TRSC metric measures the present value of the portion of ELL's total supply cost that is relevant to the portfolio analysis within the IRP. Accordingly, it excludes embedded fixed costs associated with generation, transmission, and distribution that currently exist in ELL's rate base and the impact of resource deactivations that are currently included in base rates. The non-fuel fixed costs included in the TRSC calculation are an estimate of the incremental fixed costs of the relevant resource portfolio (e.g. Portfolios 1, 2, and 3). Green tariff products such as the recently approved Rider GGO or other similar customer offerings (e.g. the recently proposed rider GZ) may allow customers to subscribe to and receive value from a share of renewable resources in ELL's future resource portfolio, reducing or eliminating the cost and risk allocated to all ELL customers.

Table 30: Portfolio 1 in Future 1 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$17,963
Resource Additions Fixed Costs	$2,585
DSM Net Fixed Costs	($232)
Capacity Purchases / (Benefit)	($104)
Total Relevant Supply Cost	$20,211

Table 31: Portfolio 2 in Future 2 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$20,301
Resource Additions Fixed Costs	$7,741
DSM Net Fixed Costs	($135)
Capacity Purchases / (Benefit)	($483)
Total Relevant Supply Cost	$27,424

Table 32: Portfolio 3 in Future 3 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$18,470
Resource Additions Fixed Costs	$2,720
DSM Net Fixed Costs	($135)
Capacity Purchases / (Benefit)	($411)
Total Relevant Supply Cost	$20,644

Figure 46 below summarizes the TRSC results for Portfolio 1, 2, and 3 under each future.

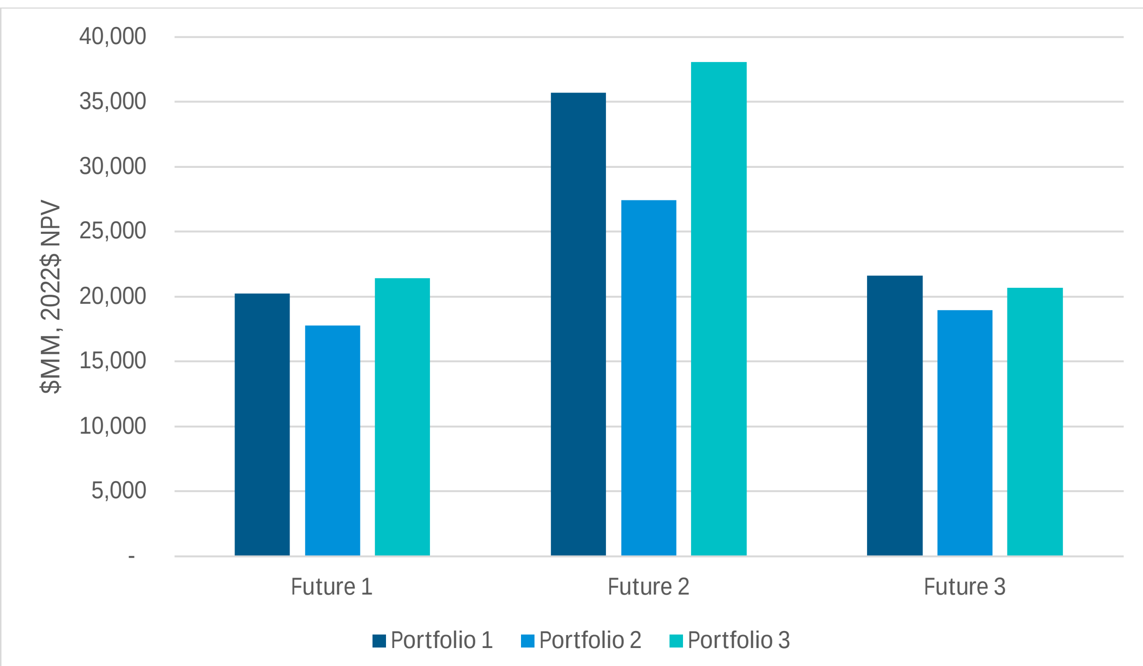

Figure 46: Portfolio Total Relevent Supply Cost by Future

To estimate the rate effects of each optimized portfolio, the incremental non-fuel fixed costs are calculated on a levelized nominal basis in terms of dollars per MWh. ELL also quantified an estimated amount of variable supply cost, or fuel, savings calculated on a levelized nominal basis by measuring the reduction in annual variable supply costs relative to the first-year cost per MWh for each portfolio. The results of this analysis presented below indicate an estimate rate effect of (¢1.06)/kWh in Portfolio 2 to ¢0.02/kWh in Portfolio 1. As noted in Chapter 5, Portfolio 2 is comprised of a significant amount of intermittent resources and relies more on the MISO energy markets than other portfolios. For the reasons described throughout this document, over-reliance on the MISO markets can pose risks to customers and reliability.

These rate impact estimates do not account for the rate effects of future customer offerings, additional AGM from load growth associated with new industrial sales from incremental electrification and load expansions, and/or the rate effects of deactivating or retiring resources, both of which may lower costs for all customers during the planning period.

Table 33: Potential Rate Impact of Portfolios

	(A) Fixed Cost [NPV $/MWh]	**(B) Fuel Savings [NPV $/MWh]**	**(A+B=C) TRSC Cost or (Savings) [NPV $/MWh]**
Portfolio 1	$3.23-$3.94	($3.72)-($2.38)	$0.02-$1.20
Portfolio 2	$9.20-$9.50	($20.14)-($12.60)	($10.64)-$3.31
Portfolio 3	$2.85-$3.59	($3.92)- ($0.17)	$(0.91)- $3.42

Overall, the net effect of this analysis across all portfolios has a minimal estimated net rate impact. The figure below shows the range on a ¢/kWh basis on a 2022$ NPV basis.

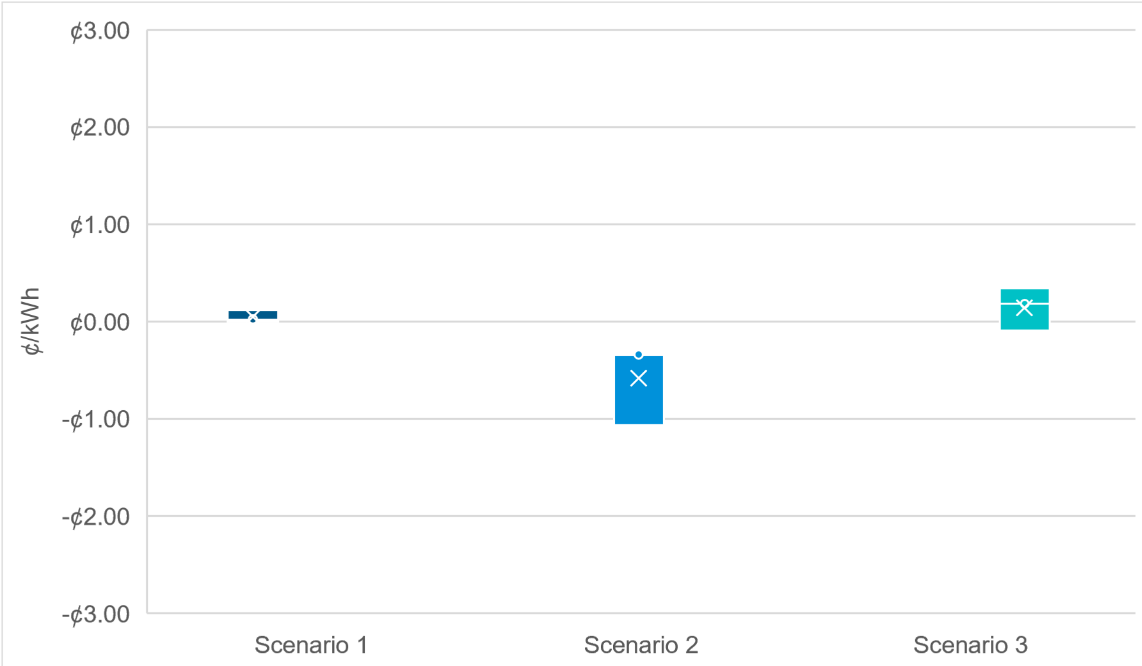

Figure 47: Estimated Net Rate Impact of Portfolios

Appendix J – Actual Historic Load and Load Forecast

Historic Peak Demand and Energy

Table 34:Actual Historic Energy (GWh) (Includes T&D Losses)

	Residential	Commercial	Industrial	Governmental	Total
2012	14,583	11,977	26,590	743	53,894
2013	14,737	11,980	27,039	759	54,516
2014	15,147	12,141	28,396	769	56,453
2015	15,129	12,294	29,120	793	57,336
2016	14,511	12,060	29,964	834	57,369
2017	14,035	11,917	31,264	830	58,046
2018	15,062	12,031	30,402	855	58,350
2019	14,596	11,798	30,969	860	58,222
2020	14,311	10,875	30,012	810	56,008
2021	14,120	10,791	31,039	823	56,772

Table 35:Summer and Winter Historical Peaks (MW)[61]

	Summer	Winter
2012	9,607	7,602
2013	9,763	7,958
2014	9,493	9,073
2015	10,358	8,824
2016	9,857	7,978
2017	9,968	8,634
2018	9,870	9,243
2019	9,929	8,394
2020	9,535	8,219
2021	10,145	8,671

Table 36:Historic Monthly Energy (MWh)[62]

	Residential	Commercial	Industrial	Governmental	Total
1/1/2012	1,184,341	916,312	2,221,892	62,767	4,385,312
2/1/2012	976,468	865,796	2,191,311	61,202	4,094,778
3/1/2012	937,649	885,876	2,208,271	60,419	4,092,216
4/1/2012	947,266	910,348	2,254,453	60,488	4,172,556
5/1/2012	1,068,155	964,145	2,225,076	59,246	4,316,622
6/1/2012	1,483,468	1,124,001	2,371,260	63,465	5,042,195

[61] Actuals are not available for revenue classes.

[62] Including T&D Losses to match forecasts values

7/1/2012	1,653,125	1,165,556	2,276,747	64,187	5,159,616
8/1/2012	1,644,084	1,164,169	2,282,967	66,309	5,157,528
9/1/2012	1,519,527	1,122,289	2,130,745	65,144	4,837,704
10/1/2012	1,247,115	1,046,879	2,081,486	64,127	4,439,606
11/1/2012	951,378	929,933	2,210,211	58,119	4,149,641
12/1/2012	970,793	881,961	2,135,383	57,659	4,045,796
1/1/2013	1,239,178	934,099	2,287,472	64,109	4,524,858
2/1/2013	1,037,088	868,703	2,194,945	65,150	4,165,886
3/1/2013	995,157	869,926	2,094,173	63,078	4,022,334
4/1/2013	905,808	859,908	2,231,557	60,230	4,057,503
5/1/2013	914,217	897,051	2,304,183	62,540	4,177,989
6/1/2013	1,343,257	1,064,993	2,384,889	63,964	4,857,103
7/1/2013	1,639,042	1,171,257	2,278,176	64,380	5,152,855
8/1/2013	1,617,130	1,144,833	2,274,144	63,429	5,099,537
9/1/2013	1,603,942	1,187,187	2,396,925	65,511	5,253,565
10/1/2013	1,373,950	1,113,313	2,211,120	64,016	4,762,399
11/1/2013	947,443	941,621	2,173,176	60,360	4,122,600
12/1/2013	1,121,259	927,562	2,208,618	61,890	4,319,328
1/1/2014	1,456,184	988,020	2,233,409	66,637	4,744,251
2/1/2014	1,436,993	968,116	2,240,145	64,724	4,709,977
3/1/2014	1,094,468	902,740	2,076,529	63,859	4,137,596
4/1/2014	898,370	882,745	2,349,036	63,522	4,193,673
5/1/2014	979,025	933,056	2,343,315	61,853	4,317,250
6/1/2014	1,298,794	1,062,598	2,388,029	65,675	4,815,096
7/1/2014	1,567,099	1,153,136	2,467,752	65,207	5,253,194
8/1/2014	1,556,573	1,141,209	2,511,980	64,727	5,274,489
9/1/2014	1,553,712	1,159,052	2,506,819	65,986	5,285,570
10/1/2014	1,255,691	1,069,587	2,465,828	60,728	4,851,834
11/1/2014	1,008,273	976,516	2,413,650	62,116	4,460,555
12/1/2014	1,041,890	904,408	2,399,251	63,733	4,409,282
1/1/2015	1,258,340	942,169	2,426,296	65,842	4,692,647
2/1/2015	1,230,047	924,813	2,356,571	65,734	4,577,166
3/1/2015	1,196,963	941,589	2,117,129	67,880	4,323,562
4/1/2015	917,579	901,724	2,253,131	64,313	4,136,747
5/1/2015	1,014,654	952,547	2,350,362	62,790	4,380,354
6/1/2015	1,342,555	1,070,967	2,486,836	68,691	4,969,050
7/1/2015	1,646,112	1,186,064	2,526,341	67,560	5,426,077
8/1/2015	1,854,193	1,271,242	2,664,070	70,444	5,859,948
9/1/2015	1,547,044	1,183,825	2,629,681	65,945	5,426,495
10/1/2015	1,227,186	1,062,426	2,378,126	63,962	4,731,700

11/1/2015	958,111	960,782	2,394,040	64,773	4,377,707
12/1/2015	935,912	895,950	2,536,953	65,455	4,434,270
1/1/2016	1,166,831	925,874	2,510,626	67,394	4,670,725
2/1/2016	1,130,914	890,826	2,445,341	74,080	4,541,161
3/1/2016	910,786	879,537	2,423,271	67,107	4,280,701
4/1/2016	822,582	858,217	2,579,768	66,065	4,326,632
5/1/2016	947,137	927,137	2,438,960	67,859	4,381,093
6/1/2016	1,297,706	1,044,764	2,645,768	70,638	5,058,877
7/1/2016	1,672,041	1,187,467	2,569,486	72,000	5,500,994
8/1/2016	1,622,890	1,176,235	2,648,915	71,982	5,520,022
9/1/2016	1,575,457	1,169,899	2,498,810	74,626	5,318,791
10/1/2016	1,375,286	1,114,239	2,506,127	70,304	5,065,956
11/1/2016	1,023,780	984,284	2,463,271	65,818	4,537,153
12/1/2016	965,286	901,610	2,233,601	66,345	4,166,842
1/1/2017	1,167,867	925,152	2,578,889	69,888	4,741,795
2/1/2017	935,695	864,103	2,438,688	66,086	4,304,572
3/1/2017	892,749	879,445	2,296,454	67,190	4,135,838
4/1/2017	919,111	899,876	2,713,117	66,937	4,599,041
5/1/2017	1,003,096	938,864	2,626,494	66,049	4,634,502
6/1/2017	1,230,741	1,028,881	2,734,606	70,301	5,064,530
7/1/2017	1,505,955	1,117,721	2,600,064	74,814	5,298,554
8/1/2017	1,539,948	1,134,881	2,696,478	71,495	5,442,801
9/1/2017	1,473,406	1,139,257	2,717,022	71,875	5,401,560
10/1/2017	1,333,600	1,101,053	2,659,150	70,535	5,164,339
11/1/2017	1,018,878	979,619	2,558,466	67,441	4,624,404
12/1/2017	1,013,617	908,593	2,644,273	67,504	4,633,987
1/1/2018	1,462,435	970,457	2,581,091	69,843	5,083,825
2/1/2018	1,238,790	920,165	2,427,996	71,074	4,658,025
3/1/2018	893,283	874,720	2,316,175	67,613	4,151,792
4/1/2018	832,753	859,822	2,608,956	66,322	4,367,853
5/1/2018	947,526	883,992	2,518,538	66,292	4,416,348
6/1/2018	1,445,497	1,100,892	2,658,378	71,208	5,275,974
7/1/2018	1,630,434	1,159,516	2,583,825	74,527	5,448,303
8/1/2018	1,620,020	1,159,611	2,640,441	74,622	5,494,692
9/1/2018	1,589,782	1,194,934	2,692,924	75,585	5,553,225
10/1/2018	1,361,650	1,113,596	2,622,481	76,017	5,173,744
11/1/2018	974,420	930,094	2,290,520	70,879	4,265,912
12/1/2018	1,065,088	863,149	2,460,409	71,398	4,460,043
1/1/2019	1,155,826	899,071	2,634,003	73,428	4,762,329
2/1/2019	1,089,931	858,047	2,612,832	69,308	4,630,118

3/1/2019	955,119	860,901	2,383,649	68,482	4,268,152
4/1/2019	872,747	859,754	2,571,589	69,241	4,373,331
5/1/2019	978,599	902,929	2,511,625	70,721	4,463,874
6/1/2019	1,391,972	1,063,359	2,704,107	72,624	5,232,062
7/1/2019	1,597,458	1,140,243	2,636,673	72,570	5,446,944
8/1/2019	1,547,320	1,133,015	2,668,632	73,677	5,422,644
9/1/2019	1,649,749	1,181,946	2,738,324	77,174	5,647,193
10/1/2019	1,408,916	1,128,575	2,631,700	75,435	5,244,626
11/1/2019	959,721	912,112	2,406,034	69,650	4,347,517
12/1/2019	988,598	857,596	2,469,811	67,336	4,383,341
1/1/2020	1,106,879	847,359	2,636,863	69,191	4,660,292
2/1/2020	1,007,891	818,603	2,675,430	68,794	4,570,718
3/1/2020	976,473	888,953	2,429,869	68,843	4,364,138
4/1/2020	986,401	803,356	2,728,529	64,815	4,583,101
5/1/2020	1,022,840	777,759	2,423,009	63,945	4,287,553
6/1/2020	1,357,139	969,894	2,566,414	67,730	4,961,178
7/1/2020	1,586,191	1,048,490	2,420,744	71,180	5,126,605
8/1/2020	1,612,971	1,072,437	2,516,508	71,737	5,273,653
9/1/2020	1,536,036	1,031,395	2,470,514	66,846	5,104,790
10/1/2020	1,143,404	948,656	2,238,927	66,776	4,397,763
11/1/2020	975,860	837,353	2,373,110	64,289	4,250,612
12/1/2020	998,801	830,343	2,532,214	65,809	4,427,167
1/1/2021	1,301,206	854,993	2,483,030	70,206	4,709,436
2/1/2021	1,088,745	823,133	2,494,870	67,656	4,474,405
3/1/2021	1,247,771	825,552	2,306,420	66,644	4,446,387
4/1/2021	846,728	790,960	2,789,237	65,584	4,492,509
5/1/2021	951,952	827,784	2,607,529	69,293	4,456,558
6/1/2021	1,286,203	979,768	2,639,884	74,722	4,980,578
7/1/2021	1,506,050	1,052,871	2,652,945	72,885	5,284,752
8/1/2021	1,573,918	1,068,341	2,836,874	71,798	5,550,932
9/1/2021	1,345,557	944,670	2,498,419	65,099	4,853,745
10/1/2021	1,099,455	900,552	2,226,838	64,230	4,291,075
11/1/2021	959,069	854,372	2,631,428	66,108	4,510,978
12/1/2021	913,489	867,854	2,871,226	68,388	4,720,956

Prior Load Forecast Evaluation

Table 37:Energy Forecasted vs Actual

Sales (GWh)	2018	2019	2020	2021
Previous IRP Sales Forecast (BP18U)*	54,961	56,509	57,967	57,780
Weather Normalized Actual Sales	55,332	55,428	54,112	54,655
Deviation	371	-1,081	-3,855	-3,125
% Deviation	1%	-2%	-7%	-5%

Table 38:Peak Forecasted vs Actual

Peaks (MW)	2018	2019	2020	2021
Previous IRP Load Forecast (BP18U)*	9,872	10,004	10,159	10,138
Weather Normalized Actual Peaks	9,654	9,850	9,530	10,112
Deviation	-218	-154	-629	-26
% Deviation	-2%	-2%	-6%	0%

Causes of Significant Deviations Between Forecasts and Actuals

COVID-19 Pandemic

The COVID-19 pandemic resulted in many behavioral changes in 2020 and 2021 which influenced actual sales for those years being different than forecasted levels from BP18U. Business closures, work-from-home, and social distancing measures caused commercial sales to be significantly lower than forecasted levels, which assumed normal behavior. Additionally, there were negative impacts to industrial load from the pandemic including lower sales to petroleum refining customers due to lower demand when travel was diminished. Off-setting some of these lower sales effects were higher sales to residential customers, as many office employees began working from home and some school-aged children began learning from home.

Industrials

ELL's forecast includes assumptions for expected levels of electricity consumption by existing large industrial customers, including assumptions about planned maintenance outages and expansions. Differences in the planned maintenance schedule vs actual maintenance schedule can cause significant deviations between forecasts and actuals. Additionally, ELL's forecast includes new and expansion industrial projects from its Economic Development pipeline on a probability-weighted basis. If a large industrial project comes online differently than what is expected in the forecast – whether that is related to a different MW size, operating level, ramp schedule, or timing – that can cause significant deviations between forecasts and actuals.

Hurricanes

Major hurricanes affecting ELL's service territory can cause deviations between forecasted sales and actual sales. Louisiana experienced the effects of multiple, significant hurricanes during 2020 and 2021 (Laura, Delta, Zeta, Ida), causing less electricity consumption across all customer classes, with some service areas of the state still seeing negative impacts from these storms.

Energy Efficiency
The sales forecast considers the historical and future effects of energy efficiency in both residential and commercial sales. This energy efficiency can come from both company-sponsored DSM programs as well as from organic energy efficiency. Differences in the actual rate of adoption of newer, more efficient technologies relative to the forecast can cause deviations between the forecast and actuals.

Peaks
All of the above factors which affected the monthly volumes of actual consumption relative to the monthly forecasts also affected comparisons of actual peak levels compared to the peak forecasts.

Explanations of revisions applied to subsequent forecasts to adjust for deviations

As a result of the factors noted above, there have been several modifications to the sales forecast models since the previous IRP forecast to adjust for previous forecast deviations. Those adjustments include:

- Estimates of the effects of the COVID-19 pandemic in historical and future sales for residential and commercial customers
- Refining the way ELL estimates its peak forecast to account for expected changes in the mix of energy between customer classes

Explanation of the effects of DSM programs, interruptible loads, or other factors on the prior load forecast

ELL's DSM programs started in 2014 and were relatively small at the time however, ELL's DSM programs have increased since the last IRP cycle, and those effects are reflected in the sales forecast which feeds into the hourly load forecast. Additionally, the current IRP forecast includes placeholder assumptions regarding the proposed Phase II DSM savings programs. These effects are roughly in-line with the high DSM scenario prepared by ICF for the IRP futures and have a larger effect in the latter years of the forecast rather than in the near-term.

The sales and load forecasts are based on historical levels of electricity consumption and therefore inherently include the effects of load that was interrupted.

Load Forecast

Table 39: Annual Energy Forecasts (GWh) (Includes T&D Losses)

[redacted]

Table 40: Summer Coincident Peaks (MW) Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	3,398	2,252	4,065	139	19	152	10,025
2024	3,387	2,254	4,242	140	19	152	10,194
2025	3,381	2,261	4,248	140	20	152	10,201
2026	3,379	2,258	4,242	140	20	152	10,190
2027	3,381	2,247	4,246	140	20	152	10,185
2028	3,386	2,234	4,271	139	20	152	10,201
2029	3,387	2,235	4,284	139	20	152	10,217
2030	3,371	2,239	4,301	140	21	152	10,224
2031	3,364	2,245	4,306	141	21	152	10,228
2032	3,370	2,235	4,321	140	21	152	10,239
2033	3,382	2,222	4,338	140	21	152	10,255
2034	3,390	2,214	4,353	140	21	152	10,270
2035	3,406	2,213	4,369	140	21	152	10,301
2036	3,406	2,226	4,379	141	21	152	10,325
2037	3,425	2,224	4,393	141	21	152	10,357
2038	3,447	2,215	4,411	141	21	152	10,387
2039	3,642	2,098	4,391	132	20	151	10,435
2040	3,688	2,101	4,404	132	20	151	10,497
2041	3,727	2,112	4,422	133	20	151	10,565
2042	3,779	2,128	4,430	134	20	151	10,642

Table 41: Winter Coincident Peaks (MW) Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	3,315	1,562	3,974	118	13	111	9,094
2024	3,318	1,552	4,042	118	13	111	9,154
2025	3,312	1,545	4,229	118	13	111	9,328
2026	3,289	1,550	4,246	119	13	111	9,328
2027	3,295	1,550	4,235	119	13	111	9,323
2028	3,285	1,545	4,267	120	13	111	9,340
2029	3,304	1,529	4,276	119	13	111	9,353
2030	3,030	1,813	4,260	143	16	104	9,367
2031	3,294	1,522	4,309	120	13	111	9,368
2032	3,272	1,526	4,332	121	13	111	9,375
2033	3,279	1,526	4,343	121	13	111	9,392
2034	3,306	1,516	4,353	121	13	111	9,421

2035	3,331	1,505	4,371	121	14	111	9,452
2036	3,365	1,497	4,360	119	13	111	9,465
2037	3,366	1,509	4,411	122	13	111	9,532
2038	3,409	1,511	4,412	122	13	111	9,579
2039	3,446	1,510	4,434	122	13	111	9,637
2040	3,509	1,503	4,443	122	13	111	9,702
2041	3,580	1,490	4,433	120	13	111	9,747
2042	3,641	1,496	4,474	122	13	111	9,857

Table 42:Monthly Energy (GWh) Forecast

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Table 43:Annual Load Factor Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	46%	58%	88%	68%	58%	50%	70%
2024	46%	57%	86%	68%	58%	50%	70%
2025	46%	57%	90%	68%	58%	50%	70%
2026	46%	57%	90%	68%	57%	50%	70%
2027	46%	57%	90%	69%	57%	50%	70%
2028	46%	57%	87%	69%	56%	50%	70%
2029	46%	57%	87%	70%	55%	50%	70%
2030	46%	56%	87%	70%	55%	50%	70%
2031	45%	56%	89%	69%	55%	50%	70%
2032	45%	56%	89%	70%	54%	50%	70%
2033	45%	56%	86%	70%	54%	50%	70%
2034	45%	56%	86%	70%	54%	50%	70%
2035	45%	56%	86%	70%	54%	50%	70%
2036	45%	56%	88%	70%	54%	50%	70%
2037	45%	56%	88%	70%	54%	50%	70%
2038	45%	56%	88%	70%	54%	50%	70%
2039	44%	56%	86%	71%	54%	50%	70%
2040	44%	56%	85%	70%	54%	50%	70%
2041	44%	56%	86%	70%	54%	50%	70%
2042	44%	56%	88%	70%	54%	50%	70%

Appendix K – Embedded Chart Inputs

[Attachment]

Appendix L – ICF DR & DER Achievable Potential Study

[Attachment]