Cleco Power LLC
2021 Integrated Resource Plan
LPSC Docket No. I-36175
Final IRP Report

May 31, 2023

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Section 1: Executive Summary

The 2021 Integrated Resource Plan ("IRP") for Cleco Power LLC ("Cleco Power" or the "Company") neither mandates specific outcomes or investment decisions, nor replaces or modifies Cleco Power's obligation to comply with the requirements of the Louisiana Public Service Commission's ("LPSC" or the "Commission") Market Based Mechanism Order[1], generation retirement reporting requirements in General Order 10-19-2018[2], or the 1983 General Order[3], as applicable. Cleco Power has not made any final decisions concerning capacity additions, modifications, or generating resource retirements that may be identified in this Final IRP Report.

In summary, Cleco Power's Action Plan[4] includes the following elements. Please see Section 8 for more detail. Capitalized terms used but not defined in the summary shall have the meaning specified elsewhere in this Final IRP Report.

- Existing Resources:
  - Retire Teche 3 after Dixie Electric Membership Cooperative, Inc. ("DEMCO") contract expiration.
  - Retire Rodemacher 2 by 2028, pending a joint owner agreement, due to the Environmental Protection Agency's ("EPA") coal combustion residual ("CCR") rule.
  - Maintain in operation the following generating units: Madison 3, Acadia Power Station, Coughlin Power Station, St. Mary Clean Energy Center and Teche 4.
  - Maintain in operation the Nesbitt 1 generating unit; evaluate replacement of Nesbitt 1 pursuant to an RFP for dispatchable resources due to aging infrastructure and environmental rules.
  - Continue Cleco Power's current EE program and pursue additional initiatives.
  - Continue to evaluate the carbon capture and sequestration project at Madison 3 ("Project Diamond Vault").
- New Resources:
  - Complete certification process for Dolet Hills Solar PPA (240 MW); currently pending in LPSC Docket No. U-36502.
  - Installation of up to 49 MW of solar power near England Airpark.
  - Issue an RFP for up to 500 MW of installed capacity ("ICAP") renewable capacity for resources to be placed in service prior to January 1, 2027. Request up to 150 MW of battery storage options (both stand-alone and project add-ons).

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[1] General Order in LPSC Order No. R-26172, Subdocket C, issued October 29, 2008 (the "MBM Order").
[2] General Order in LPSC Order No. R-34407, issued October 19, 2018 (the "Generation Retirement Order").
[3] General Order in LPSC Order No. R-30517, issued May 27, 2009 (the "1983 General Order")
[4] The projected resource additions do not represent firm planning decisions. Cleco Power will continue to comply with the LPSC's 1983 General Order and the LPSC's MBM Order regarding capacity resource additions.

  - Issue an RFP for up to 500 MW of accredited all-season capacity options that can be dispatched in times of need, that complements the intermittency of renewable resources, and that demonstrates a technology pathway to be carbon-free in the future.
  - Issue additional Renewable and Battery RFPs pending results of the first RFP issuance and updates to customer load growth forecasts. Accelerated electrification load development and rapid emergence of industrial load opportunity will be monitored, pursued, and may impact the additional RFP issuance scope and scale.
- Continue to monitor and comply with existing and potential future environmental regulations.
- Actively participate in Midcontinent Independent System Operator, Inc. ("MISO") working groups and stakeholder processes.
- Actively monitor and participate in Resource Adequacy dockets at the LPSC.
- Actively monitor and participate in MISO seasonal construct discussions and processes.

Introduction

This Final IRP Report describes the process and results of Cleco Power's 2021 IRP, which was initiated on October 20, 2021 in LPSC Docket No. I-36175. The objective of the IRP is to evaluate a comprehensive set of potential resource options for Cleco Power as it operates in the MISO regional transmission organization market and to outline a potential plan that offers an economic, reliable, and resilient resource portfolio. The proposed portfolio supports demand requirements, provides customers with affordable solutions, and reduces Cleco Power's carbon footprint based upon current assumptions. Certain assumptions have been updated from Cleco Power's February 21, 2022, Draft IRP assumptions to reflect more recent market conditions/changes and to address stakeholder feedback, to the extent possible. These updates are noted throughout this Final IRP report.

This is the sixth IRP report developed by Cleco Power since 2004, and the third under LPSC Docket No. R-30021. IRP findings and results included:

- 2004 IRP report – Cleco Power issued the "*2004 Request for Proposals ("RFP") for Capacity and Energy Resources*" for 800 megawatts ("MW") of base load and intermediate generation and 250 MW of peaking generation.

- 2007 IRP report – Cleco Power issued the "*2007 Long-Term RFP for Capacity and Energy Resources*" for 600 MW of intermediate generation and 350 MW of peaking generation.

- 2012 IRP report – Cleco Power issued the "*2012 Request for Proposals for Long-Term Capacity and Energy Resources*" for 800 MW of intermediate generation.

- 2015 IRP report – Cleco Power determined that it had sufficient capacity and energy resources to sustain reliable and economic generation through 2030.

- 2019 IRP report – Cleco Power intended to issue a "[r]enewable RFP of up to 500 MW of unforced renewable capacity." However, due to a material change in circumstances related to the loss of the DEMCO load and a resulting planning reserve margin reduction, the Renewable RFP was not issued.

- Cleco Power has now applied for a certificate of public convenience and necessity for a solar Power Purchase Agreement ("PPA") between Cleco Power (as buyer) and Dolet Hills Solar, LLC (as seller) for solar energy, capacity, and other products from a 240 MW solar facility to be constructed near Dolet Hills Power Station (the "Dolet Hills Solar PPA").[5] This project is using the MISO replacement generation process to utilize the existing Dolet Hills Power Station interconnection.

As with previous IRPs, Cleco Power's primary concerns include reliability, deliverability, price and price volatility, fuel diversity and stability, environmental uncertainty, and environmental goals. More specifically, key issues addressed in this Final IRP Report include:

- potential retirement of aging generating resources in Cleco Power's existing generation portfolio;
- new capacity additions related to replacing retiring units and/or meeting new and existing customer demand; and
- uncertainty surrounding the impact of future environmental regulations.

This report does not address assets owned by Cleco Cajun LLC ("Cleco Cajun"). Cleco Power and Cleco Cajun are wholly-owned, direct subsidiaries of Cleco Corporate Holdings LLC. Per the Federal Energy Regulatory Commission ("FERC") Affiliate Restrictions regulations, Cleco Power and Cleco Cajun maintain separate operations and management to the maximum extent possible. Therefore, Cleco Power's IRP does not address Cleco Cajun's generating fleet or its future planning.

Also included in this Final IRP Report is a description of Cleco Power's preferred portfolio ("Optimized Portfolio") to serve as a guideline for meeting near-term resource requirements. Cleco Power will thoroughly consider the results of this IRP when internally deliberating decisions required to continue reliably serving its customers in the future. The IRP results are intended to present the most beneficial solution for Cleco Power's customers, depending on the accuracy of the assumptions at a specific point in time. The goals set forth in the Action Plan may be adjusted as market conditions change and as assumptions can be refined.

By engaging stakeholders, Cleco Power is addressing a range of perspectives that will support the analysis contained in this Final IRP Report. Stakeholder input helps to ensure that the assumptions used are appropriate and that relevant viewpoints on Cleco Power's role as an electricity provider

[5] *See* LPSC Docket No. U-36502.

will be considered. Cleco Power appreciates stakeholder feedback and has incorporated stakeholder feedback and suggestions throughout the IRP process, as appropriate.

State of the Utility Business

Planning for the future is challenging, and successful planning involves acute awareness of the environment in which Cleco Power currently operates, as well as giving critical thought to positioned readiness for action that captures sustainable value for all of Cleco Power's stakeholders. Global priorities and strategies are changing, markets are evolving and emerging, and the utility industry is a vital agent for leadership and execution. This IRP demonstrates awareness and presents a plan for Cleco Power to capture value for its existing customers, new customers, equity and debt investors, and the State of Louisiana while maintaining unyielding focus on and no adverse impacts to the reliable availability of electricity for consumption by the Company's customers.

Awareness and key drivers for planning in this IRP include:

- the Inflation Reduction Act of 2022[6] as a catalyst for investment and empowerment of vertically integrated utility participation;
- access to affordable capital, underwritten by planning and execution of ESG goals;
- demand from existing customers for an affordable and reliable power product;
- demand from emerging customers for an affordable, reliable, and clean power product; and
- implementation of policy changes by MISO and Regulators related to resource adequacy, including Seasonal Accreditation Construct and Minimum Capacity Obligation rules.

IRP Process

As noted previously, Cleco Power initiated its 2021 IRP by submitting a *Request to Initiate IRP Process* to the LPSC on October 20, 2021, pursuant to the requirements of Section 10, Attachment A of the LPSC's General Order (Corrected) issued April 20, 2012, in Docket R-30021 ("IRP Order"). Also pursuant to the IRP Order, an updated procedural schedule is included in Table 1.1, below.

Table 1.1: Expected Schedule of IRP Events

Event Description	Completion Date
Submit request to initiate the IRP	October 20, 2021

[6] H.R. 5376, Public Law No. 117-169 (08/16/2022).

File data assumptions	February 21, 2022
First stakeholder meeting	March 24, 2022
Stakeholders file written comments	May 24, 2022
Publish draft IRP report	October 26, 2022
Second stakeholder meeting	November 29, 2022
Stakeholders file second set of written comments	January 31, 2023
Staff files written comments	February 28, 2023
Publish final IRP report	May 31, 2023
Stakeholders file disputed issues and alternative recommendations	July XX, 2023
Staff files recommendation to LPSC	August XX, 2023
Commission Order acknowledging IRP or procedural schedule	October XX, 2023

To date, Cleco Power has

- submitted the Request to Initiate an IRP;
- filed its initial data assumptions;
- held the first stakeholder meeting;
- received written comments from stakeholders and LPSC Staff about the assumptions;
- provided updated assumptions and responses to discrete written comments;
- published a Draft IRP Report;
- held a second stakeholder meeting to review the results;
- received additional comments from stakeholders and the LPSC Staff; and
- published a Final IRP Report (*i.e.*, this IRP Report).

Upcoming events in the 2021 IRP are to consider disputes and alternative recommendations, if any, from stakeholders (including LPSC Staff).

Following these tasks, LPSC Staff will file a recommendation with the LPSC either recommending that the LPSC acknowledge the Final IRP Report as being in compliance with the IRP Order, or recommending the setting of a procedural schedule before an administrative law judge to address any disputed issues. The next IRP cycle is scheduled to be initiated in October 2025. However, this schedule neither precludes Cleco Power from initiating that process sooner, nor does it preclude Cleco Power from submitting an IRP update in the interim, as contemplated and permitted by the IRP Order.

Development of the IRP

Major factors that contributed to the creation of Cleco Power's Optimized Portfolio include:

- load and peak demand;
- expected electrification;
- the condition of Cleco Power's current resources;
- fuel considerations;
- energy efficiency and demand-side resources;
- environmental regulations;
- renewable energy pricing trends;
- the potential outcome of the rulemaking currently pending in LPSC Docket No. R-36263, in which the Commission is considering establishing a minimal physical capacity threshold for load serving entities ("LSEs") within Louisiana.
- MISO's seasonal construct for Planning Reserve Margin Requirements for the 2023/24 Planning Resource Auction ("PRA"). Cleco Power has integrated this construct change into the modeling and planning efforts for this Final IRP Report. This construct is explained in more detail in Section 7.

Section 2: Load and Peak Demand

Load forecasting techniques used in the development of the IRP primarily considered forecasted economic data, population data, and weather. Cleco Power engaged Woods & Poole Economics, Inc. ("Woods & Poole"), an economics consultant based in Washington, D.C., for forecasted economics and population data. Weather projections were based on National Oceanic and Atmospheric Administration ("NOAA") normal cooling degree days ("CDD") and heating degree days ("HDD"). Peak demand forecasts were based on historical system load factors, and representative hourly load shapes. A further discussion of peak demand and load forecast techniques and results can be found in Section 2: Load and Peak Demand.

Section 3: Current Resources

Cleco Power's electric generating units ("EGUs") are generally in good operating condition and have been maintained in accordance with prudent utility practice. Rodemacher Unit 2 ("Rodemacher 2"), a Powder River Basin ("PRB") coal-fired plant located at the Brame Energy Center in Rapides Parish near Boyce, LA, will cease coal-fired operation by 2028 due the EPA's CCR rule, resulting in a loss of 142 MW unforced capacity ("UCAP") of generating capacity for Cleco Power.

Cleco Power is currently undergoing a Front-End Engineering Design ("FEED") study to determine the feasibility of a carbon capture and sequestration ("CCS") project at its Madison Unit 3 ("Madison 3"), located at the Brame Energy Center in Rapides Parish near Boyce, LA. Pending the study's results, Madison 3 could have a 200 MW reduction of generating capacity if the CCS project is implemented.

Teche Power Station Unit 3 ("Teche 3"), a 305 MW UCAP natural gas steam turbine in Saint Mary Parish, LA, is expected to retire in 2024 pending the results of MISO's PRA. A discussion of Cleco Power's existing EGUs and details on recent major maintenance efforts undertaken in connection with the Company's EGUs is in Section 3: Current Resources.

Section 4: Fuel Considerations

Cleco Power primarily utilizes natural gas, PRB coal, Illinois Basin Coal, and petroleum coke ("petcoke") to power its existing EGUs. Fuel procurement is subject to material risks, most notably price risk and delivery risk. To account for price risk, Cleco Power developed sensitivities that account for a range of natural gas outcomes. While some deliverability risk exists in securing firm natural gas pipeline transportation and maintaining sufficient solid fuel inventory levels, Cleco Power is rarely forced to curtail generation due to an inability to secure fuel. This and other topics are discussed in greater detail in Section 4: Fuel Considerations.

Section 5: Regional Transmission Development

Since Cleco Power's integration into MISO in December 2013, Cleco Power has worked with MISO and other transmission owners to form transmission strategies. Cleco Power actively participates in MISO's Transmission Expansion Plan ("MTEP") to evaluate potential transmission projects. Additionally, Cleco Power is active in MISO's Long Range Transmission Planning ("LRTP"), with a focus to improve the ability to move electricity across the MISO region reliably and at the lowest possible cost. Section 5: Regional Transmission Development, details MISO's transmission planning process, reserve margin requirements, Cleco Power's upcoming transmission projects, and resource adequacy.

Section 6: Environmental Considerations

Numerous existing and potential future environmental regulations may play a significant role in Cleco Power's resource planning process. Consistent with its philosophy, Cleco Power will proactively address and comply with all environmental mandates. This IRP considers all existing and relevant proposed regulations, which are detailed in Section 6: Environmental Considerations.

Section 7: Resource Needs and Other IRP Assumptions

Other assumptions were used for modeling, including reserve margin, new resource alternatives, potential demand side resources, pre-screening analysis, modelling sensitivities, carbon dioxide ("CO2") cost projections, and financial assumptions. These topics are further discussed in Section 7: Resource Needs and Other IRP Assumptions.

Section 8: Results and Modeling

Cleco Power used Energy Exemplar's Aurora Forecasting Software ("Aurora") version 14.1, to develop this IRP. Aurora features a linear optimization process with iterative calculations to find the most cost-effective solutions that meet future load-serving needs, while considering operational and economic constraints.

Cleco Power performed analyses on three scenarios: Reference Case, Upside Electrification Case, and Environmental Case. Assumptions differ for each case with respect to peak demand and load growth, fuel prices, and environmental compliance policies and costs. In addition to the three major scenarios, Cleco Power performed sensitivity analyses on the Reference Case, Upside Electrification Case, and Environmental Case. These sensitivities include "constrained supply" (high) and low natural gas prices and CO2 emission costs.

Cleco Power's new resource alternatives were evaluated using pre-screening analyses to narrow the resource options that are considered in the remainder of the IRP process. Cleco Power examined the levelized cost of energy ("LCOE") for the new resource alternatives grouped by class (combined cycles, combustion turbines, and renewables) to determine whether certain technologies were clear leaders in lowest cost within their respective class. Technologies determined to be high cost within each class were removed from consideration in the Aurora market model. Further details of this process can be found in Section 7 under Pre-Screening New Resources.

Long-term portfolio optimization models were performed using a zonal construct with transmission constraints between each defined zone. A further discussion of Aurora modeling cases and the modeling process is provided in Section 7 and Section 8.

Section 9: Stakeholder Feedback

Section 9 of this Final IRP Report contains Cleco Power's responses to stakeholders' comments regarding Cleco Power's Draft IRP Report.

Optimized Portfolio and Action Plan

As discussed in Section 8, the Optimized Portfolio is premised on resource selections by the Aurora model given load, commodity, and market assumptions at this time. It is then optimized to consider certain factors that cannot be practically modeled within Aurora that need to be given additional consideration. Please see Appendix 11 for further context on optimization criteria. The Optimized Portfolio will be used for cross-testing, demonstrating performance and outcomes in different scenarios and sensitivities. The outcomes will be economically measured against other optimized portfolios within the Aurora scope of constraints and targets. Actual results from a competitive RFP process may vary. Therefore, the Optimized Portfolio is only a guide toward developing an Action Plan. It is not a final, definitive, resource solution and will be subject to testing in a competitive RFP process. Additionally, current capacity and energy markets are extremely dynamic, and the potential for unforeseen circumstances always exists.

After reviewing and analyzing the results of the various portfolios, Cleco Power has identified an Optimized Portfolio. The Optimized Portfolio includes adding the following by 2030:

- 240 MW (ICAP) of Dolet Hills PPA solar capacity and energy: 2025;
- 250 MW (ICAP) of owned solar capacity and energy: 2026;
- 250 MW (ICAP) of owned solar capacity and energy: 2027;
- 150 MW of installed battery storage: 2027;
- 400 MW of installed 1x1 (one GT/HRSG train to one ST) combined cycle gas turbine: 2028; and
- Additional Energy Efficiency initiatives and benefits.

Any changes to Cleco Power's portfolio of generation assets will be highly dynamic and contingent upon multiple factors. Those factors include:

1. MISO's immature seasonal PRA construct and associated market and Cleco Power customer impacts;
2. Certification of the Dolet Hills Solar PPA by the LPSC (currently pending in LPSC Docket No. U-36502);
3. Pending Minimum Capacity Obligation determinations and rulemaking;
4. Affordable and reliable clean energy technological advancement by 2030; and
5. Madison 3 CCS project execution (*i.e.*, Project Diamond Vault).

Cleco Power anticipates:

- the retirement of Teche 3 as soon as reliably, economically, and logistically feasible. Factors 1 and 3, above, may change this expectation;
- the retirement of Rodemacher 2 by 2028; and
- evaluating Nesbitt 1 for replacement while considering the EPA's Cross-State Air Pollution Rule (see Section 6: Environmental Considerations for more detail).

Nesbitt 1 will continue to be evaluated for replacement after Cleco Power's Power Supply and Service Agreement with DEMCO expires on March 31, 2024. Replacement of this EGU, paired with the prospective additional 338 MW UCAP reduction at Brame Energy Center (arising out of the cessation of the coal-fired operation at Rodemacher 2 and the reduction of Madison 3 capacity due to Project Diamond Vault), will require a resource or combination of resources that are affordable, dispatchable, and, at a minimum, have the capability to convert to a net-zero carbon emitter to help Cleco Power reduce its greenhouse gas emissions.

The commercial operation dates of the renewable and dispatchable capacity should coincide with or pre-date the reductions of capacity at Brame Energy Center to the extent practically possible.

Cleco Power intends to align new resource additions with the most likely time frames in which Cleco Power's existing unit retirements or capacity reductions are expected to occur.

It is important to note that the assumptions used in this IRP do not represent binding or indicative bids received from actual suppliers or from construction contractors and are intended to reflect potential opportunities that likely exist in the market. Factors such as price, deliverability, energy shapes, and credit impacts can materially change the economic impact of new resource evaluations. Additionally, significant potential costs, such as transmission upgrades, are not included in the IRP analysis due to the uncertain location of where the resources may be sited.

Based on the results of this IRP, it is expected that Cleco Power will initiate the procedures specified in the MBM Order for the commencement of an RFP (specifically, the filing of a notice of intent to initiate an RFP). While the IRP results indicate a combination of solar, on-shore wind, batteries, and gas-fired turbines as the most economic options over the next 5-7 years, RFPs will allow proposals from a variety of technologies.

Section 2: Load and Peak Demand

Rate Classes

Cleco Power tracks and forecasts energy consumption by cost of service ("COS") class for ratemaking purposes, rather than by FERC revenue class (*e.g.*, residential, commercial, industrial). Cleco Power also tracks and forecasts peak demand for its system as a whole and not just for each COS class. COS classes are detailed in Table 2.1, below.

Table 2.1: Description of COS Classes

Rate Class	Description
Residential	Private Residences
General Service Energy Only	Commercial Energy Billed Customers
General Service Primary	Large C&I Demand Billed Customers
General Service Secondary	Small C&I Demand Billed Customers
Large Power	Systems Over 15 MW
Other Retail	Municipal, Lighting, and Schools

Wholesale	Sale for Resale

Historic Load and Peak Demand

Annual historic load by COS class and for Cleco Power's system as a whole are presented in Table 2.2, below. Monthly load data is presented in Appendix 1.

Table 2.2: Historic Annual Load by Customer Class (Gigawatt-hours ("GWh"))

Rate Class	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Residential	3,953	3,854	3,601	3,690	3,759	3,763	3,621	3,472	3,779	3,629	3,620	3,684
GS Energy Only	326	320	304	314	315	321	313	301	328	313	292	306
GS Secondary	2,080	2,112	2,142	2,154	2,194	2,216	2,156	2,125	2,177	2,165	2,071	2,057
GS Primary	1,077	1,045	1,055	1,022	1,021	1,036	1,030	1,028	1,057	994	972	1,049
Large Power	1,048	1,202	1,148	1,175	1,037	743	857	930	1,014	847	888	1,025
Other Retail	507	495	474	487	488	500	487	479	501	530	439	468
Wholesale	801	1,281	1,487	1,518	2,899	3,070	2,924	2,786	2,933	2,879	2,914	2,861
Total	9,793	10,309	10,210	10,360	11,713	11,649	11,388	11,121	11,790	11,357	11,196	11,450

Seasonal and annual peak demand figures for Cleco Power's system are shown in Table 2.3, below. Monthly peak demand figures are presented in Appendix 1. Cleco Power does not track peak demand by customer class.

Table 2.3: Historic Annual System Peak Demand (Megawatts ("MW"))

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Summer Peak	2,348	2,355	2,282	2,278	2,612	2,700	2,490	2,508	2,494	2,492	2,536	2,497
Winter Peak	2,310	2,201	1,818	1,906	2,470	2,679	2,138	2,404	2,879	2,326	2,121	2,649
Annual Peak	2,348	2,355	2,282	2,278	2,612	2,700	2,490	2,508	2,879	2,492	2,536	2,649

Energy Forecasting Methodology

Cleco Power's Service Territory

Cleco Power's retail-jurisdictional service territory is located entirely in the State of Louisiana. A significant portion of the territory is located in the central part of the state, with an additional area located north of New Orleans, commonly referred to as Northlake. The weather throughout Cleco Power's service territory is relatively consistent during both the summer and winter because the area is fairly compact. Therefore, Cleco Power only uses three NOAA weather stations to analyze the weather: New Orleans, New Iberia, and Alexandria. Typically, there is little variation between these three weather stations.

Annual energy growth in Cleco Power's service territory is moderate and within a small range of 0.3% to 0.4% per year. Any larger growth is typically due to the execution of a power supply contract with a new industrial customer or the addition of a new wholesale customer. The service territory consists of approximately 291,000 customers, of which 248,000 are residential. The customer and energy breakout is shown in Table 2.4, below.

Table 2.4: 2021 Customer Count and MWh Sales

COS Class	Customer Count	Sales (MWh)
Residential	248,376	3,684,157
GS Energy Only	28,292	305,559
GS Secondary	8,267	2,056,843
GS Primary	105	1,049,069
Large Power	8	1,025,235
Other Retail	6,321	468,381
Wholesale	7	2,860,830
Total	291,376	11,450,074

Energy Forecasts

Cleco Power forecasts energy for all COS classes. These classes make up the entire Cleco Power load. The following is a list of those COS classes:

1. Residential customers, including Power Miser;
2. Small commercial customers billed only on energy;
3. GS secondary customer class billing demand levels;
    a. e10 – billing kW ≤ 100 kW
    b. e20 – 100 kW < billing kW ≤ 500 kW
    c. e30 – 500 kW < billing kW ≤ 1,000 kW

    d. e40 – over 1,000 kW

4. GS primary customer class billing demand levels;
    a. g10 – billing kW ≤ 100 kW
    b. g20 – 100 kW < billing kW ≤ 500 kW
    c. g30 – 500 kW < billing kW ≤ 1,000 kW
    d. g40 – over 1,000 kW
5. Large Power Service – customers over 15,000 kW;
6. Other Retail: Lighting, Municipals, Schools, and Churches; and
7. Wholesale customers.

Forecasting some of these classes requires Cleco Power to have exogenous economic data. This data is purchased from Woods & Poole, located in Washington, D.C. Woods & Poole specializes in providing long-term economic and demographic data. Woods & Poole updates projections with new historical data each year. The company has been performing these analyses since 1983. The data provided includes population data, employment levels, income (real and nominal), wages/salaries, and household statistics. All data is provided at the following levels: country, state, parish, and municipal service area.

The database used for all regression-based forecasting is created from the Woods & Poole data. Since this data is provided by parish, the economic data used is only for those parishes within Cleco Power's service territory, which includes 24 of the 64 Louisiana parishes. All forecasts are stated as monthly data.

Residential Class Forecast

Since the residential class is a large part of Cleco Power's load and is naturally homogeneous, Cleco Power forecasts the total number of customers and then each residential customer's energy use under normal weather conditions. The total energy use for the residential class is derived with estimates for normal use per consumer and a total number of consumers.

Residential Customer Forecast

Woods & Poole provides a population growth forecast for Cleco Power's service territory. A regression analysis was performed with Woods & Poole's population forecast with respect to Cleco Power's residential customers.

Historically, the growth rate in the number of Cleco Power's residential customers has been close to Louisiana's population growth rate, which is approximately 0.2% per year (2010 through 2021).

Since 2010, Cleco Power has added an average of approximately 1,300 new residential consumers per year.

Table 2.5: Residential Class Premise Report

Year	Residential Premises	Growth by Year
2010	238,606	0.4%
2011	240,066	0.6%
2012	240,647	0.2%
2013	241,747	0.5%
2014	243,342	0.7%
2015	243,653	0.1%
2016	245,783	0.9%
2017	246,287	0.2%
2018	246,935	0.3%
2019	245,969	-0.4%
2020	247,357	0.6%
2021	248,376	0.4%

As can be seen in Table 2.5, Cleco Power's residential premise (*i.e.*, the number of residential meters served at the end of the calendar year) growth has been relatively consistent since 2010, with a compound annual growth rate of 0.37%. Cleco Power devised a second method of forecasting the number of residential customers, which is to apply a trend to the growth rate in the number of customers. By combining this method with the regression analysis, Cleco Power projects its number of residential customers to grow by between 0.3% and 0.5% per year.

Residential Use Per Consumer

To forecasting residential use per consumer ("UPC"), Cleco Power uses a regression analysis. Cleco Power uses monthly data to forecast a normal residential UPC. The following regression equation is used:

$$res\_upc_n = c + \beta_n * moDum_n + \beta_n * norCDD_n + \beta_n * norHDD_n + e$$

where,

res_upc = residential use per consumer

c = constant term

n = 1-11 (for month)

moDum = dummy variable for each month (minus one)

norCDD = NOAA normal cooling degree days

norHDD = NOAA normal heating degree days

e = error term

The assumption for using a dummy variable for each month is that each month will have varying base usage, and the dummy variable will separate that from any usage caused by weather as represented by the NOAA degree days.

The last step to derive residential usage per year is the following equation:

$$res\_kWh_n = res\_con_n * res\_upc_n$$

where,

res_kWh = total residential usage per month

res_con = number of residential consumers per month

res_upc = normal single residential usage per month

n = 1-12 (monthly data)

Forecasting Small Commercial Customers (Billed Energy Only)

Even though the non-demand billed class (General Service Energy Only or "GSO") is commercial and has a slightly larger variance in usage relative to the residential class, these customers are impacted by weather in a manner similar to the residential class. Cleco Power assumes the similarities between this class and the residential class are sufficient to forecast their usage using a methodology similar to that of the residential class.

GSO Customer Forecast

Cleco Power assumes the number of customers in the GSO class is mainly driven by movements in the residential class, since customers within the GSO class depend on the proximity of population to their business locations. With this assumption, Cleco Power does not regress GSO customers on population growth of the service territory (as in the residential class), but rather calculates the ratio of GSO consumers to residential consumers. This ratio has been relatively constant since 2001, as shown by the statistics, below:

Mean = .113	Range = .018
Mode = .113	Min = .105
Median = .112	Max = .124

Relying on the assumption of a constant ratio between the GSO and residential classes, the forecast of GSO consumers is calculated with the following equation. The calculation is done for each month.

$$GSO\_Customers_n = ratio(gso_{con}: res_{con}) * res_{con}$$

where,

gso_{con} = GSO customers

res_{con} = Residential customers

GSO Use Per Consumer Forecast

Regression analysis is used when forecasting usage for the GSO class. Below is the regression equation:

$$gso\_upc_n = c + \beta_n * moDum_n + \beta_n * norCDD_n + \beta_n * norHDD_n + e$$

where,

gso_upc = usage per consumer

c = constant term

n = 1-5 (months June through September)

moDum = dummy variable for each summer month (June through September)

norCDD = daily NOAA normal cooling degree days

norHDD = daily NOAA normal heating degree days

e = error term

The forecast attempts to derive normal usage for GSO customers by regressing NOAA normal degree days on historical use per consumer for the GSO class. A dummy variable for the summer is included to recognize any change in usage due to the change in rate for Crop Irrigation customers, a subsection of the GSO class. Summer is defined as June through September.

Using the previous two equations, usage is calculated for the GSO class. The equation is:

$$GSO\_kWh_n = GSO\_Customers_n * \ gso\_upc_n$$

where,

GSO_kWh_n = usage for GSO class

$GSO\_Customers_n$ = number of customers in GSO class

gso_upc_n = GSO use per consumer

Forecasting General Service Customers with < 1,000 kW

General Service Customers < 1,000 kW (energy, customer, and demand forecasts)

The General Service ("GS") customers are both commercial and industrial loads that are billed based on demand. Therefore, these customers can be classified within demand classes that are shown below:

GS primary customer class billing demand levels

a. g10 – billing kW ≤ 100 kW

b. g20 – 100 kW < billing kW ≤ 500 kW

c. g30 – 500 kW < billing kW ≤ 1,000 kW

d. g40 – over 1,000 kW (forecasted individually)

GS secondary customer class billing demand levels

a. e10 – billing kW ≤ 100 kW

b. e20 – 100 kW < billing kW ≤ 500 kW

c. e30 – 500 kW < billing kW ≤ 1,000 kW

d. e40 – over 1,000 kW (forecasted individually)

All customers that have a billing demand of less than 1,000 kW, regardless of whether they are served from secondary or primary voltage, are forecasted using an assumption that the class load factor remains relatively constant. Since a class load factor is relatively constant, a demand forecast is all that is needed to derive an energy forecast. Furthermore, the billing demand for these customers is ratcheted demand based on the applicable approved tariff. With a ratcheted demand, the billing demand is set for 12 months based on the highest reading during summer months (June through September). Therefore, when the forecast of the GS classes begin, the demand levels are known for most of the first 12 months of the forecast. The equation for estimating usage is below:

$$kWh_{class} = kW_{billing} * load_{factor_{class}} * hours\ in\ period$$

Generally, there is very little movement within the GS class unless an identified new customer contracts with Cleco Power to build within the service territory, or an existing customer in this class expands its operations.

General Service Customers < 1,000 kW, Customer Forecasts

Once the energy and demand forecasts are derived by using the above procedure, Cleco Power only needs customer forecasts. Cleco Power bases the customer forecast using at least a 5-year look back of customer growth and assumes that growth will remain constant through all forecast years.

Forecasting Municipals and Lighting

The Municipal and Lighting classes account for about 0.7% of Cleco Power's total load. In 2021, Residential Lighting, Commercial Lights, and Municipal Lighting accounted for a combined 79,400 MWh. Generally, there is little to no growth in these classes; therefore, they are forecasted with little to no growth.

Classes Forecasted Individually

Certain customers are forecasted individually and, thus, do not require a long-term general customer forecast. These classes are held constant at current levels unless otherwise directed by customer service representatives that a new customer has executed a contract for service. The following customers are analyzed and forecasted individually:

1. General Service Secondary, billing kW > 1,000
2. General Service Primary, billing kW > 1,000
3. Large Power Service, billing kW ≥ 15,000
4. Wholesale Customers (sales for resale)

Customer service representatives will provide information concerning major changes to any existing customers and provide notification if any new customers are to be added to the system. These changes are included in the base forecast.

Cleco Power expects a loss of wholesale customers over the next two years (and had a wholesale contract expire in December 2022). Table 2.6, below, shows Cleco Power's wholesale customers and when each contract expires.

Table 2.6: Wholesale Customer Expiration Date

Customer	Expiration
DEMCO	March 2024
Erath	September 2023
Gueydan	December 2025
Mississippi Delta Energy Agency	May 2023
St. Martinville	December 2022

The effects of the existing Quick Start Energy Efficiency ("EE") program and distributed generation are embedded in historical customer usage data, and are not explicitly modeled as a line item reduction to load. The effects of new programs that would cause a material deviation in the load forecast, such as the EE market potential study, are modeled as a resource option in Aurora, rather than as a direct reduction in the load inputs. Further details regarding the effects of EE and demand-side resources assumed in this Final IRP Report are in Section 7 and Appendix 3.

Line Losses

Cleco Power conducts an internal study to determine the amount of line losses that occur on its transmission and distribution systems. To determine line losses, a team from Cleco Power disaggregated Cleco Power's system by service level based on line voltage and evaluated losses over a range of system load levels. The resulting loss factors are shown in Table 2.7, below:

Table 2.7: Transmission and Distribution Loss Factors by Customer Type

System Type	Customer Type	End-Use Line Size	Energy Loss Factor
Transmission	Wholesale, C&I	69 kV – 230 kV	2.28%
Sub transmission	C&I	34.5 kV	3.33%
Primary	C&I	2.4 kV – 24.9 kV	4.08%
Three Phase Secondary	Commercial	480 V	5.44%
Single Phase Secondary	Residential	120 V	6.59%

Peak Demand Forecasting Methodology

To forecast annual system peak demand, Cleco Power first calculates the peak month's (typically August) average load factor for the past five years using actual peak demand and load data. The average peak month load factor is then applied to forecasted monthly system load in the peak month to project annual peak demand.

Historical load shapes are then used to project hourly demand shapes. To find the proper shape, Cleco Power first calculates the five-year average load for every hour of the year. Rather than finding the average load for a specific hour (*e.g.*, hour ending at 0100 on January 1), Cleco Power ranks each day of each month for the previous five years based on peak demand, and finds the average load for every hour of each individually ranked day. This prevents averaging where, for example, a winter day of one year may be extremely cold and that same day of another year may be very mild. Thus, volatility of daily peaks throughout a month are maintained throughout the forecast. Once the hourly shape is calculated, it can be scaled up or down on a ratio basis to meet the annual peak demand forecast as well as the annual energy forecast.

Accuracy of Previous IRP Forecasts

The peak demand and load forecasts for Cleco Power's previous IRP were conducted during 2018. The first year of the previous IRP was 2019. Therefore, forecast versus actual variances can be analyzed for 2019, 2020, and 2021. Table 2.8, below, shows the differences between forecast and actual load for those years, along with reasons for material deviations. Demand-side management programs and interruptible loads did not have a material effect on the forecasts' accuracy.

Table 2.8: Previous IRP Annual Load Forecast Accuracy

Year	2019	2020	2021
Forecast (GWh)	11,457	11,434	11,480
Weather Effect	12	47	108
Large Power Impact	246	119	14
Other Impacts	(357)	(403)	(152)
Actual	11,357	11,196	11,450
Forecast Error	(0.9%)	(2.1%)	(0.3%)
Weather-adjusted Error	0.3%	1.19%	2.72%

The previous forecasts for 2019 and 2020 were within approximately one percent of actual load on a weather-adjusted basis. Most of the weather-adjusted variances in 2020 and 2021 are related to policies enacted during the COVID-19 pandemic. During these years, the load was shifted to residential consumers as more people worked from home because commercial businesses closed.

Peak demand forecasts are inherently less accurate due to the instantaneous nature of system peaks. A single weather event or short stretch of abnormal weather, or lack thereof, could cause peak demand to vary, but would have minimal impact on annual load forecasts. The differences between forecast and actual summer peak demand since Cleco Power's most recent IRP are detailed in Table 2.9, below:

Table 2.9: Previous IRP Annual Peak Demand Forecast Accuracy

Year	2019	2020	2021
Forecast (MW)	2,688	2,707	2,722
Actual	2,492	2,536	2,497
Forecast Error	(7.9%)	(6.7%)	(9.0%)

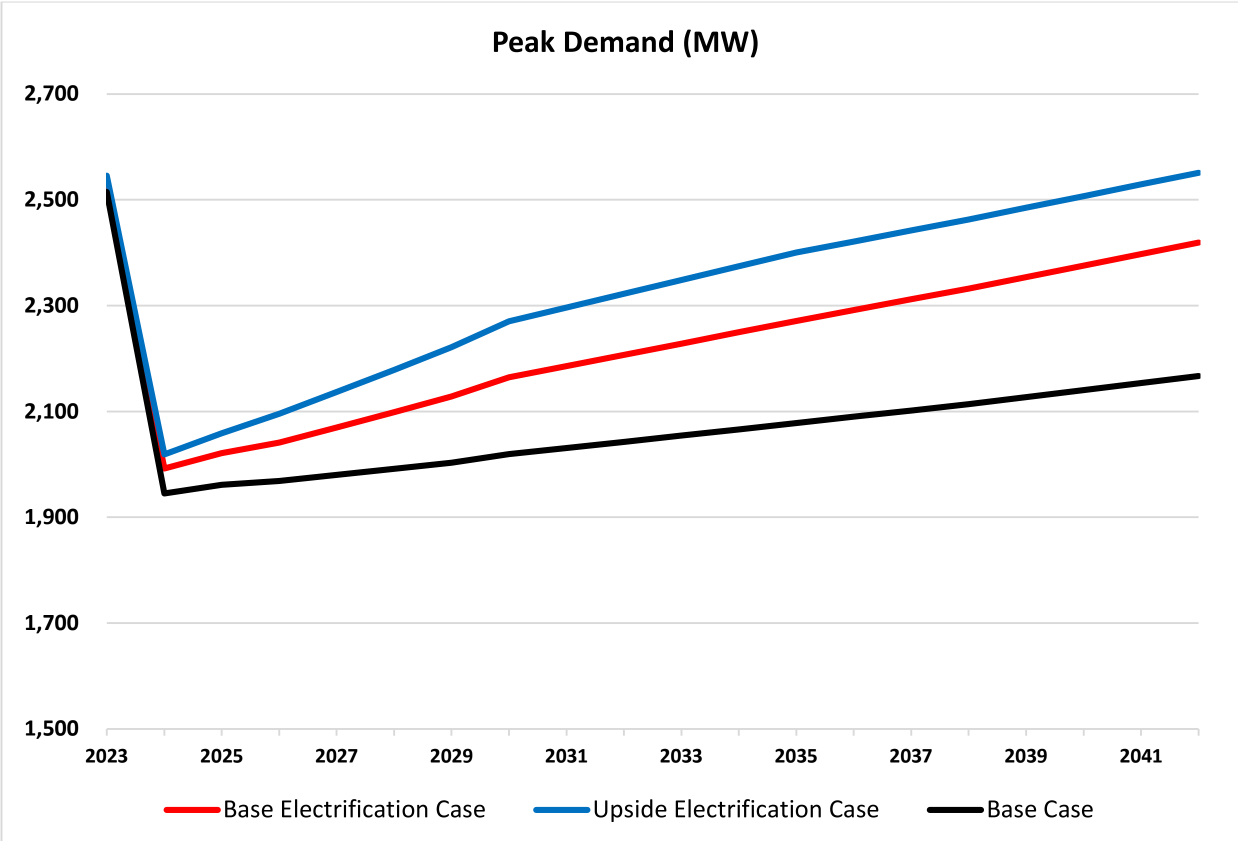
Changes in Methodology from Previous IRP

Cleco Power has not materially changed its peak demand and load forecasting methodologies since it filed its last IRP. Load projections are still based on normal NOAA CDDs and HDDs as well as Woods & Poole economic data, neither of which have materially changed. Total system forecasts are updated to reflect Cleco Power's current retail and wholesale load.

Forecasted Load and Peak Demand

Forecasted annual peak demand is shown in Figure 2.1, below. Figure 2.1 also shows Cleco Power's generation capacity assumptions. The capacity assumptions are discussed further in Section 3: Current Resources.

Figure 2.1: Peak Demand and Capacity



Forecasted load and peak demand data can be found in Appendix 1. Load forecasts disaggregated by COS class do not extend past 2034. Cleco Power does not forecast peak demand for COS classes; system peaks are reported.

MISO recently partnered with Purdue University in coordination with the State Utility Forecasting Group to develop its own independent load forecast for the MISO region. However, MISO has decided that the independent load forecast will be used in transmission planning only, and MISO will continue to rely on the individually submitted forecasts of LSEs for purposes of resource adequacy and planning.

Emerging Technologies and Interruptible Load

Behind-the-Meter Battery Storage

Energy storage offers multiple benefits for both the energy grid and electric customers. It facilitates the integration of renewable energy resources, such as wind and solar, in the energy grid by helping to balance the often-erratic production levels. Energy storage may also help improve electric reliability by providing grid stability services, reducing transmission constraints, and meeting peak demand. Behind-the-meter ("BTM") storage may be economical for commercial and industrial customers to reduce their peak consumption levels. As prices continue to decline, BTM storage may also become a viable resource for residential customers to enable more productive time of use ("TOU") tariffs to shift peak demands, or to expand the use of renewable energy. While utility-scale battery storage is included as a resource alternative (*see* Section 7), BTM battery storage has not yet reached a sufficient adoption level to materially influence Cleco Power's peak demand. Cleco Power will continue to work with commercial and industrial customers to include battery storage as a solution on a customer-specific basis.

Distributed Energy Resources & Microgrids

Distributed energy resources ("DER") include examples such as rooftop solar, small-scale gas generators, energy storage, smart appliances, and vehicle to grid. Residential and commercial customers increasingly see these products and services as a way to manage their own energy use, save money, reduce their carbon footprint, and increase reliability. As formal, utility-backed programs, DERs often require complex tariffs, terms, and conditions. Also, particularly regarding rooftop solar versus large utility-scale solar projects, the utility-scale projects can take advantage of economies of scale that see prices far below those obtainable by DERs. Cleco Power did not include DERs as distinct resource alternatives in this Final IRP Report, but will continue to examine commercial strategies to make these options available to its customers. Cleco Power is partnering with the University of Louisiana at Lafayette ("ULL") to create a microgrid testing lab at the Cleco Power Alternative Energy Center to better prepare for DER orchestration and integration. Cleco Power is also closely monitoring MISO's compliance with FERC Order No. 2222.

Non-Wires Alternatives

Non-wires alternatives are electricity grid investments or projects that use non-traditional transmission and distribution solutions, such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as new lines or transformers, by reducing load at a substation or circuit. Non-wires alternatives have the potential to be economically competitive alternatives to the traditional approach of relying on new construction to meet changing transmission needs.

Long-Term Duration Energy Storage

Long-term duration energy storage is any technology that can be deployed competitively to store energy for prolonged periods, and that can be scaled up economically to sustain electricity provision for multiple hours, days, or even weeks, and has the potential to significantly contribute to the decarbonization of the economy. Energy storage can be achieved through very different approaches, including mechanical, thermal, electrochemical, or chemical storage. Studies have estimated that by 2040, long-duration energy storage has the potential to deploy 1.5 to 2.5 terawatts ("TW") of power capacity—globally, or eight to 15 times the total energy-storage capacity deployed today. Long-duration energy storage still needs to mature both in terms of technology and costs before it can become a consideration for Cleco Power.

Small Modular Reactors

Small Modular Reactors ("SMRs") are advanced nuclear reactors that have a power capacity ranging from 10MW(e) up to 300 MW(e) per unit. Given their smaller footprint, SMRs can be sited on locations not suitable for larger nuclear power plants. Prefabricated units of SMRs can be manufactured, shipped, and installed on site, making them more affordable to build than large power reactors, which are often custom-designed for a particular location, sometimes leading to significant construction delays and cost overruns. SMRs offer savings in cost and construction time, and can be deployed incrementally to match increasing energy demand. More than 70 commercial SMR designs currently being developed around the world to target varied outputs and different applications, such as electricity, hybrid energy systems, heating, water desalination, and steam for industrial applications. Though SMRs have a lower upfront capital cost per unit, their economic competitiveness remains to be proven in practice once they are deployed. In a special report, the International Atomic Energy Agency identified nuclear, including SMRs in advanced economies, as a key source of electricity in a net-zero 2050 scenario.

Hydrogen

Hydrogen use today is dominated by industries such as oil refining or ammonia production; however, technological advances and cost reduction could increase the competitiveness of hydrogen for use in transport, buildings, power generation, and storage. With declining costs for solar PV and wind generation, building electrolyzers at locations with excellent renewable resource conditions could become a low-cost and low-carbon supply option for hydrogen, even after considering the transmission and distribution costs of transporting hydrogen from often remote locations to the end-users. ULL, with Cleco Power's support and federal and state funding (H_2theFuture Hydrogen Grant), will be adding a Green Hydrogen Center with a Green Hydrogen Testbed to the Cleco Power Alternative Energy Center.

<u>Interruptible Load</u>

Cleco Power currently has 18 MW of interruptible load that reduces the amount of capacity required to meet firm demand. Cleco Power does not anticipate that the amount of interruptible load will significantly change in the future. Industrial customers have historically not requested to participate in programs that would allow their electric service to be controlled or interrupted during production periods. However, the results of the demand response market potential study are included as a resource option that can be selected in the Aurora model.

Electrification

Cleco Power engaged consultants to develop an electrification strategy to encourage customers to invest in gas compression and electric vehicles. Cleco Power is incorporating two electrification scenarios into the 2021 IRP: a "Base Case Electrification" and an "Upside Case Electrification." Cleco Power assumes that as the liquified natural gas ("LNG") market continues to expand, new natural gas compressor stations will select electric-motor-driven equipment utilizing Cleco Power's transmission and distribution infrastructure as part of widespread adoption of environmental, social, and governance ("ESG") targets. Cleco Power's electrification strategy is also rooted in the assumption that light, medium, and heavy-duty trucks will begin to adopt electricity as their fuel of choice. The adoption rates consider that electric vehicle utilization will increase inside Cleco Power's service territory. Adoption outside of Cleco Power's service territory will increase utilization of electric infrastructure across key interstate systems throughout Cleco Power's service territory. The adoption rate increase is based on vehicle manufacturers' targets and government mandates.

[redacted]

[redacted]

[redacted]

[redacted]

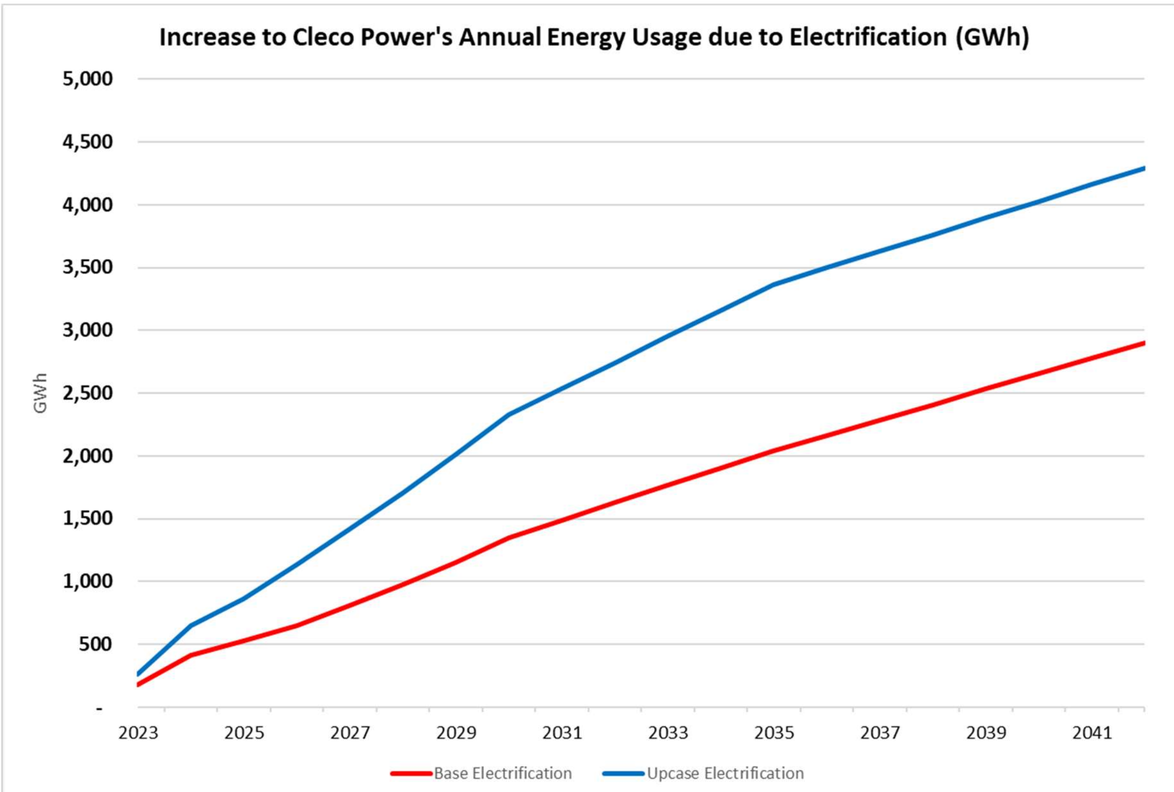
Green Tariff

Cleco Power anticipates filing a new green tariff in 2023 that corresponds with an updated filing with the LPSC for the Dolet Hills Solar PPA project in LPSC Docket No. U-36502. Cleco Power's fleet must include dedicated renewable resources to supply future and existing customers with green energy that will allow them to meet their ESG targets before energy can be sold under a green tariff. Dependent upon Cleco Power securing additional renewable resources in the future, the initial green tariff may be amended for additional green tariffs to be filed.

Modeling Methodology

Figure 2.2, below, illustrates the annual GWh growth attributed to electrification in this Final IRP Report. As adoption increases, additional energy will need to be produced to satisfy growing demand.

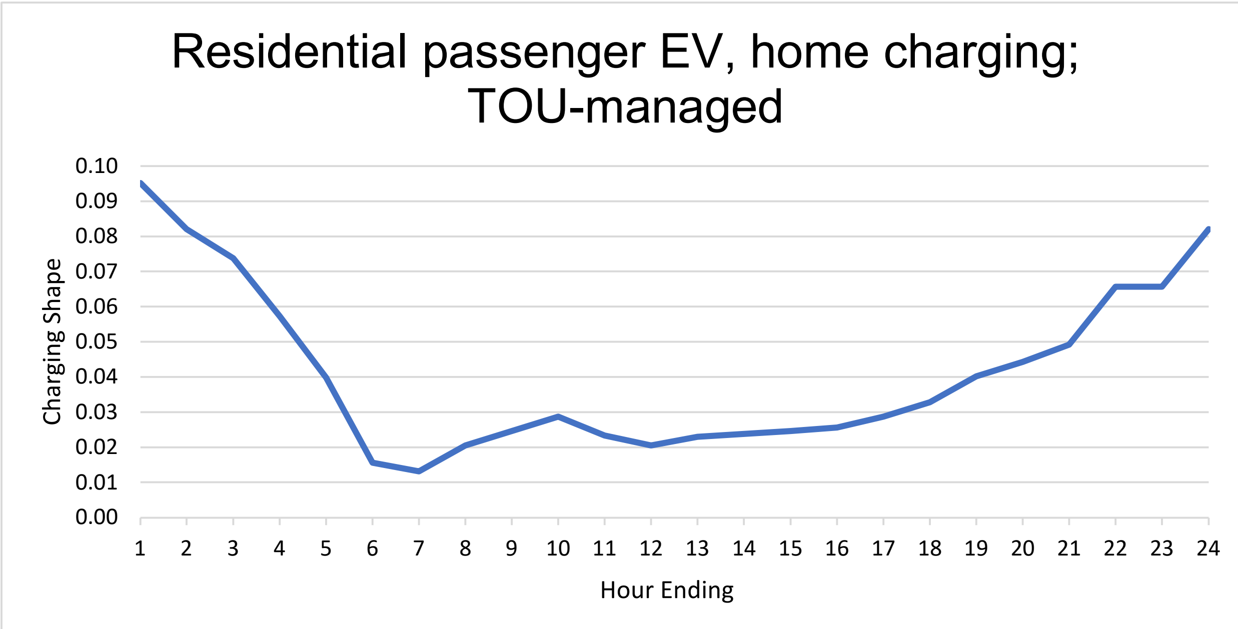
Figure 2.2: Electrification's Energy Contribution



To model potential electrification in Aurora, the energy needed to be converted into an aggregate, hourly shape for each hour of the year.

Electric vehicles were assumed to have the same daily charging shape, as shown in Figure 2.3, below. The annual energy load was divided by 365, then multiplied by the shape for each hour of the year (8760 hours). Charging loads by electric vehicles and e-trucking are assumed to primarily be during off-peak hours.

Figure 2.3: EV and E-Trucking Daily Shape

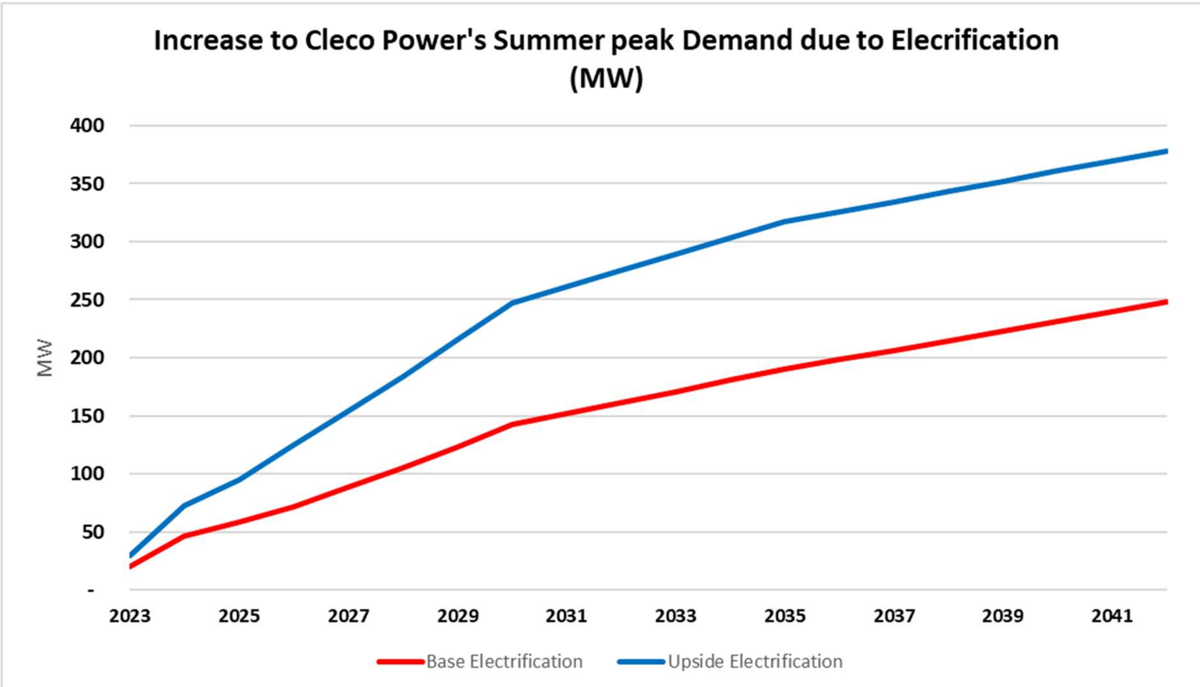


Gas compression is assumed to have consistent, around-the-clock usage. Therefore, to derive the hourly usage, the forecasted potential annual energy was divided by 8760 hours. The hourly usage is then applied to every hour of the year.

By aggregating the pieces together, a unified electrification hourly shape was derived for both cases on an annual basis.

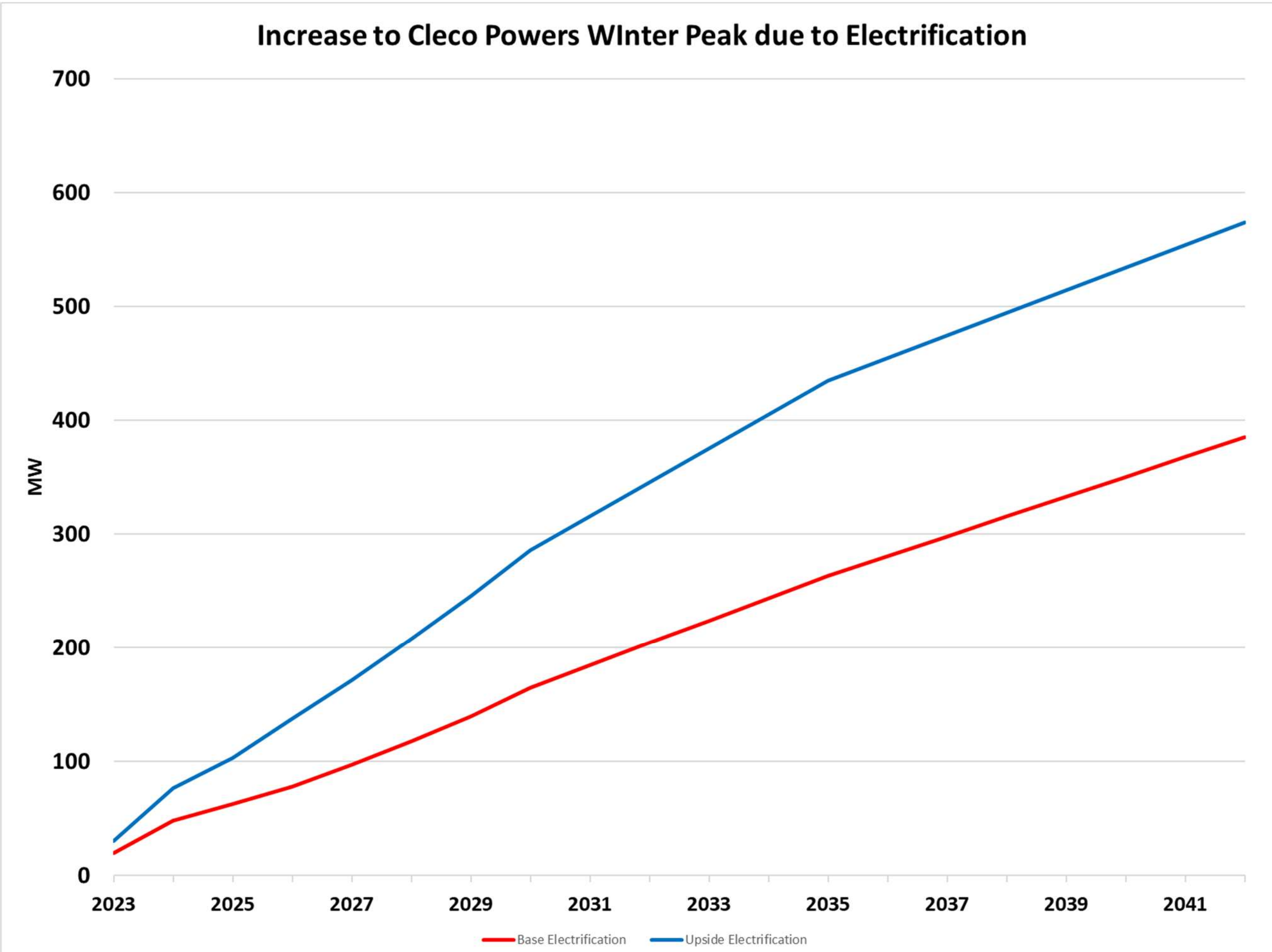
In Figure 2.4, below, the coincidental peak demand increase is shown for the Base Electrification Case and High Electrification Case. For modeling purposes, Cleco Power's peak occurs at 4:00 p.m. on August 12.

Figure 2.4: **Demand Contribution to Cleco Power's Summer Peak**



In Figure 2.5, below, the coincidental winter peak demand increase is shown for the Base Electrification Case and High Electrification Case. For modeling purposes, Cleco Power's peak occurs at 8:00 a.m. on January 24.

Figure 2.5: Demand Contribution to Cleco Power's Winter Peak



IRP Inputs

Although the factors discussed above may not be specifically included in Cleco Power's base load forecast, Cleco Power did project load and peak demand for its electrification sensitivities. These sensitivities were derived from the referenced load forecast and were adjusted upward using the two different electrification cases.

Cleco Power's peak demand calculations include 18 MW of interruptible load, a 1.7% transmission loss rate, and reserve margins that differ by each season. Seasonal reserve margins are discussed further in Section 7.

Section 3: Current Resources

Existing Supply-Side Resources

Electric Generating Units

Table 3.1, below, lists Cleco Power's owned EGUs.

Table 3.1: List of Cleco Power EGUs

Plant	Unit	COD	Fuel Type	Net Capacity (ICAP)	[redacted]
Brame Energy Center	Nesbitt 1	1975	Natural Gas	422	[redacted]
	Rodemacher 2	1982	PRB Coal	493[7]	[redacted]
	Madison 3	2010	Petcoke/Coal	628	[redacted]
Acadia Power Station (PB1)	Acadia	2002	Natural Gas	557[8]	[redacted]
Coughlin Power Station	Coughlin 6	2000	Natural Gas	239	[redacted]
	Coughlin 7	2000	Natural Gas	480	[redacted]
Teche Power Station	Teche 3	1971	Natural Gas	335	[redacted]
	Teche 4	2011	Natural Gas	34	[redacted]
St. Mary Clean Energy Center		2019	Waste Heat	47	[redacted]

Detailed descriptions of each EGU are included, below.

[7] Cleco Power owns 147 MW (30%), Lafayette owns 246 MW (50%), and LEPA owns 98 MW (20%).
[8] Cleco Power owns 100% of Power Block 1. Entergy Louisiana, LLC owns 100% of Power Block 2.

Acadia Power Station

Table 3.2: General Resource Information, Acadia Power Station

General Resource Information	
Resource Type	Combined Cycle
Operating Capacity (PB1)	557 MW
Fuel Type	Natural Gas
Ownership[9]	Cleco Power 50%, Entergy 50%
Location	Acadia Parish, LA
COD	2002

Acadia Power Station ("Acadia") is a combined cycle gas turbine ("CCGT"), natural-gas-fired EGU equipped with selective catalytic reduction ("SCR") systems. Acadia began operation in 2002 and is in good overall condition. Major systems and equipment have been maintained in accordance with prudent utility practice. Acadia is expected to maintain high availability and reliability assuming sound maintenance practices continue.

Major maintenance projects undertaken at Acadia include:

- Reheater Drain Modifications in 2021;
- Cooling Tower Structure Upgrade in 2020; and
- Rebuild HP, IP, & Bypass CCI Valves in 2021.

[9] Cleco Power owns 100% of Power Block 1. Entergy Louisiana, LLC owns 100% of Power Block 2.

Coughlin Power Station

Table 3.3: General Resource Information, Coughlin Power Station

General Resource Information	
Resource Type	Combined Cycle
Operating Capacity	719 MW
Fuel Type	Natural Gas
Ownership	Cleco Power 100%
Location	Evangeline Parish, LA
COD	2000

The repowered Coughlin Power Station ("Coughlin") is a CCGT, natural-gas-fired EGU equipped with SCR systems. Coughlin began operations in 2000 and is in good overall condition. Major systems and equipment have been maintained in accordance with prudent utility practice. Coughlin is expected to maintain high availability and reliability assuming sound maintenance practices continue.

Major maintenance projects undertaken at Coughlin include:

- Unit 6 2300V Switchgear Upgrade in 2020;
- Unit 7 2300V Switchgear Upgrade in 2021;
- Coughlin Water Purification Filtration Project in 2021;
- Unit 6 and 7 Duct Burner Upgrades in 2021;
- Unit 6 CT Major in 2020;
- Unit 7 CT and ST Major Inspection in 2021;
- Unit 6 ST Valve Inspection in 2021; and
- Unit 7 ST Voltage Regulator Replacement in 2019.

Rodemacher Unit 2

Table 3.4: General Resource Information, Rodemacher Unit 2

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	493 MW
Fuel Type	Subbituminous Coal
Ownership	Lafayette Public Power Authority 50%, Cleco Power 30%, Louisiana Energy & Power Authority 20%
Location	Rapides Parish, LA
COD	1982

Rodemacher Unit 2 ("Rodemacher 2") is a solid-fuel-fired EGU at the Brame Energy Center ("Brame") equipped with an electrostatic precipitator, a fabric filter baghouse, low NO_x burners, selective non-catalytic reduction ("SNCR"), dry sorbent injection ("DSI"), activated carbon injection ("ACI") systems. Rodemacher 2 began operations in 1982 and is in good overall condition. Major systems and equipment have been maintained in accordance with prudent utility practice. Rodemacher 2 is expected to maintain high availability and reliability assuming sound maintenance practices are continued. In accordance with the EPA's CCR rule, Cleco Power (and its joint owners) will cease operations of Rodemacher 2 by 2028.

Major maintenance projects undertaken at Rodemacher 2 include:

- Steam Turbine Major Inspection in 2020;
- LP Turbine Blade Replacement in 2020; and
- Replace 590 Dozer in 2020.

Madison Unit 3

Table 3.5: General Resource Information, Madison Unit 3

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	628 MW
Fuel Type	Petroleum Coke, Coal
Ownership	Cleco Power 100%
Location	Rapides Parish, LA
COD	2010

Madison 3 is a solid-fuel-fired circulating fluidized bed ("CFB") EGU at Brame equipped with a fabric filter baghouse and limestone bed injection, SNCR, and recirculating dry FGD systems. Madison 3 began operations in 2010 and is equipped with state-of-the-art technology that provides efficient heat rates and low emissions. Major systems and equipment have been maintained in accordance with prudent utility practice. Madison 3 is expected to maintain high availability and reliability assuming sound maintenance practices continue. Cleco Power anticipates that, beginning in 2028, Madison 3 will be derated 200 MW due to Cleco Power's CCS project, Project Diamond Vault.

Major maintenance projects undertaken at Madison 3 include:

- Steam Turbine Major Inspection in 2019;
- E-Crane Replacement in 2019;
- Replace Boiler Scrubber Venturies in 2020;
- Upgrade Reclaim Feeders in 2020 and 2021;
- Replace L-1 ST Blades in 2019;
- Replace ST N2 Packing in 2019; and
- Boiler Furnace Floor Refractory & Nozzle Replacement in 2019.

Nesbitt Unit 1

Table 3.6: General Resource Information, Nesbitt Unit 1

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	422 MW
Fuel Type	Natural Gas
Ownership	Cleco Power 100%
Location	Rapides Parish, LA
COD	1975

Nesbitt Unit 1 ("Nesbitt 1") is a natural-gas-fired EGU at Brame. Nesbitt 1 began operations in 1975 and is in good overall condition. Major systems and equipment have been maintained in accordance with prudent utility practice. Nesbitt 1 is expected to maintain high availability and reliability assuming sound maintenance practices continue.

Major maintenance projects undertaken at Nesbitt 1 include:

- ST Valve Inspection in 2020; and
- Upgrade Steam Analysis Panel in 2020.

Teche Unit 3

Table 3.7: General Resource Information, Teche Unit 3

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	335 MW
Fuel Type	Natural Gas
Ownership	Cleco Power 100%
Location	St. Mary Parish, LA
COD	1971

Teche Power Station Unit 3 ("Teche 3") is a natural-gas-fired EGU. Teche 3 began operations in 1971 and is currently in degraded condition compared to Cleco Power's other EGUs. Major systems and equipment are expected to require higher maintenance investment to provide high availability. Cleco Power anticipates retiring Teche 3 in May 2024, pending the results of MISO's PRA. Issues such as MISO system reliability and regulatory treatment must be addressed before a firm retirement date can be established. These issues are discussed further in Section 8 under Existing Unit Pre-Screening Analysis.

Major maintenance projects undertaken at Teche 3 include:

- Replace Boiler Insulation in 2019 and 2020.

Teche Unit 4

Table 3.8: General Resource Information, Teche Unit 4

General Resource Information	
Resource Type	Combustion Turbine
Operating Capacity	34 MW
Fuel Type	Natural Gas
Ownership	Cleco Power 100%
Location	St. Mary Parish, LA
COD	2011

Teche Unit 4 ("Teche 4") is a natural-gas-fired EGU with black-start capability. Teche 4 began operations in 2011 and is in good overall condition. The combustion turbine, originally placed in service in 1992 by another utility, was refurbished and restored to zero operating hours before being acquired and installed at its present location by Cleco Power. Major systems and equipment have been maintained in accordance with prudent utility practice. Teche 4 is expected to maintain high availability and reliability assuming sound maintenance practices continue.

No major maintenance has been required at Teche 4 in recent years.

St. Mary Clean Energy Center

Table 3.9: General Resource Information, St. Mary Clean Energy Center

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	47 MW
Fuel Type	Waste Heat
Ownership	Cleco Power 100%
Location	St. Mary Parish, LA
COD	2019

St. Mary Clean Energy Center ("SMCEC" or "St. Mary CEC"), includes a waste heat recovery steam generator, steam turbine generator, and ancillary balance of plant equipment. The facility generates power through waste heat recovered from Cabot Corporation's carbon black manufacturing facility. St. Mary CEC began operations in 2019 and is in good overall condition. Major systems and equipment have been maintained in accordance with prudent utility practice. St. Mary CEC is expected to maintain high availability and reliability assuming sound maintenance practices continue.

Other Supply-Side Resources

Cleco Power currently has one active PPA with the Sabine River Authority of Louisiana for approximately 18 MW of renewable energy produced by a hydroelectric EGU on the Toledo Bend Reservoir. The PPA expires on May 31, 2023.

Qualifying facilities ("QFs") located within Cleco Power's local balancing authority ("LBA") have transferred an annual average of 13,000 MWh to Cleco Power over the past four years. This volume is immaterial and is netted against Cleco Power's load before submittal to MISO.

The Cleco Power LBA also has approximately 20-25 MW of distributed renewable generation.

Cleco Power's industrial customers have cogeneration on six sites with a total capacity of 309 MW. Two of Cleco Power's industrial customers anticipate creating cogeneration capacity over the next two years, but the final output of these two cogeneration projects is currently unknown.

Existing Demand-Side Resources

Demand Response

TOUCH Program

Cleco Power initiated the Time of Use Choice ("TOUCH") program at the beginning of 2014. The program and the resulting TOU rates are designed to encourage off-peak usage and discourage on-peak usage. "On-peak" is defined as the weekday hours of 1:00 pm through 7:00 pm during the summer months of May through September. This, in turn, should suppress peak demand. Currently, enrollment in the pilot program has been capped at 2,000 customers, and participation has ranged from 600 to 1,800 customers. Cleco Power began promoting the program for 2019. Table 3.10, below, shows the coincidental peak demand for the TOUCH program compared to Cleco Power's peak summer demand for 2019 through 2022.

Table 3.10: Annual Results of TOUCH

Year	TOUCH Demand (MW)	Cleco Summer Peak (MW)	% of Peak
2019	6.04	2,492	0.24%
2020	5.99	2,536	0.24%
2021	5.76	2,497	0.23%
2022	8.43	5,533	0.33%

Energy Efficiency

Cleco Power currently has an active Quick Start EE program implemented pursuant to LPSC Order No. R-31106. The program began on November 1, 2014, and Cleco Power is currently in program year eight.

After three years of operating the program with a third-party administrator, Cleco Power decided to self-operate the Quick Start program during 2018. A new department was created with employees dedicated to executing the Quick Start program. During this time, the Quick Start program was rebranded as Cleco Power Wise. The Cleco Power Wise program offers rebates, financial incentives, and technical assistance to Cleco Power's residential and non-residential customers through the following programs:

Residential Weatherization Program

The residential weatherization program provides financial incentives to single-family dwelling residents. The low- or no-cost weatherization program is contractor-driven through a network of approved weatherization contractors who conduct initial assessments of customers' houses. The contractors present residents with available EE measures and, if the customer chooses, the contractors will implement the measures in the home. Typical measures include duct sealing, air sealing, and installing of attic insulation. Also, if a customer chooses to install weatherization measures, the customer is offered free installation of up to 30 LED lightbulbs, low-flow showerheads and aerators (for electric water-heated homes), which results in additional energy savings for the customer at no cost.

Multi-Family Weatherization Program

The multi-family weatherization program targets multi-family buildings for weatherization services. The multi-family buildings are defined as residential properties containing five or more premises under a continuous roof, five or more premises under the same address, or a community of five or more premises managed or owned by a single management facility or corporation. The program is similar to the single-family program and is also delivered through a network of approved contractors who provide similar low- to no-cost measures.

Income Qualified Weatherization Program

The income qualified weatherization program targets low-income customers for weatherization services. The program offers the same measures as the Single- and Multi-Family Weatherization but with a higher incentive which enables contractors to provide energy efficiency improvements at no cost to the customer.

Residential Equipment Rebate Program

The residential equipment rebate program offers cash rebates to Cleco Power's residential customers when they purchase qualified, energy-efficient equipment. The Power Wise program provides cash rebates for high-efficiency air conditioners, heat pumps, pool pumps, smart thermostats, water heaters, room air conditioners, and geothermal heat pumps. There is also a new construction rebate to reward customers for installing these high efficiency measures at construction. The program requires customers to submit a rebate application with supporting material, such as proof of purchase and proof of installation. The qualified equipment must meet Energy Star certification criteria.

Online Marketplace Program

The online marketplace program provides instant rebates to Cleco Power residential customers who purchase qualified, energy-efficient equipment. The marketplace is an online store for the customers to choose and purchase smart thermostats, LED bulbs, low-flow water-saving devices and advanced power strips.

Small Commercial Program

The small commercial program provides financial incentives to eligible Cleco Power commercial customers with an annual average demand of less than 100 kW. The financial incentives are offered through a network of approved contractors and include measures such as installing energy-efficient LED lighting retrofits, lighting controls, and high-efficiency HVAC equipment.

Small Business Kit Program

The small business kit program allows small businesses served by Cleco Power to receive a kit containing energy-saving devices. The kit is delivered to the customer by a Cleco Power-approved contractor to discuss further energy-saving opportunities offered by Power Wise programs.

Large Commercial and Industrial Program

The large commercial and industrial program provides financial incentives to eligible Cleco Power commercial customers with an annual average demand of 100 kW or greater. These customers include school districts, colleges, and public entities. The financial incentives are offered for measures that include eligible energy-efficient LED lighting retrofits, lighting controls, and high-efficiency HVAC equipment.

Commercial Kitchen Rebate

The commercial kitchen rebate offers rebates for energy-efficient, commercial kitchen equipment such as electronically commutated motors, commercial ovens, fryers, ice machines, steam cookers, griddles, and pre-rinse spray valves. The qualified equipment must meet Energy Star certification criteria.

Residential Elementary Education Program

The residential elementary education program is a kit-based program designed to educate sixth grade elementary students about EE. The program is a turnkey approach that combines a set of classroom activities with projects in the home to install energy efficient and water conservation products. Students receive a take-home kit full of energy and water-efficient products to be installed in the home. The students are encouraged to share the learning experience with their family members, and work on subjects required by state learning standards to understand the value of natural resources in daily life. The program shapes new behaviors and achieves immediate savings results through an innovative and effective mix of new-product installation and resource-efficiency knowledge.

Residential Retail Lighting Program

The retail lighting program is a midstream lighting program providing an instant discount at the point of sale for the qualified and eligible residential LED lighting. The program partners with retailers such as Home Depot, Lowe's, Walmart, and Dollar General stores to bring discounted residential lighting products to the stores located primarily in rural areas where there is traditionally lower participation in Cleco Power's Power Wise programs.

Commercial Custom Program

The commercial custom program is a catch-all program for commercial and industrial customers to implement energy-efficiency projects that are not available under either the Power Wise small commercial or large commercial programs.

Online Home Energy Audit

The virtual home assessment is a software tool that provides a personalized list of EE recommendations and programs that customers may qualify for to improve the efficiency of their home.

Market Transformation Program

The Cleco Power Wise program is partnering with ULL to cover a portion of energy audit costs to target businesses that are Cleco Power customers. The purpose of this program is to invest in training in the energy sector as well as to drive EE awareness among hard-to-reach businesses, identify EE opportunities, and facilitate installation of EE projects at these businesses by offering financial incentives and rebates through Power Wise programs.

Overall, Cleco Power's Power Wise program performance through December 2022 is shown in Table 3.11, below.

Table 3.11: Cleco Power Wise Performance through December 2022

Sector	Energy Savings (kWh)	Demand Savings (kW)
Residential	90,839,408	18,114
Non-Residential	59,681,315	9,219
Total	150,520,723	27,333

Based on the Power Wise program's performance to date, Cleco Power anticipates meeting the goals set for the program during program year nine, which are stated in Table 3.12, below:

Table 3.12: Cleco Power Wise PY9 Goal

Sector	Energy Savings (kWh)	Demand Savings (kW)
Residential	17,165,212	3,224
Non-Residential	11,587,293	1,510
Total	28,752,505	4,734

Section 4: Fuel Considerations

Introduction

Cleco Power currently operates a diverse generation fleet that primarily utilizes natural gas, coal, and petcoke. Fuel is procured in both the spot and forward markets and transported to EGUs by pipeline, barge, rail, and conveyor.

Natural Gas Considerations

Natural gas is the primary fuel used for electric generation in Louisiana. In 2020, natural-gas-fired generation provided 70% of electricity produced by utilities and independent power producers in Louisiana. The next most used fuel types were nuclear and coal at 17% and 4% of state generation, respectively.[10]

Cleco Power procures most of its natural gas in the day-ahead and intraday natural gas markets. Because large industrial users of natural gas, including electric utilities, generally have low priority among natural gas users in the event of pipeline curtailments, Cleco Power contracts for firm transportation capacity for a portion of its requirements and maintains a moderate amount of natural gas storage to mitigate potential fuel delivery disruptions. Firm transportation capacity is typically not contracted beyond the current year. Cleco Power has contracted with Pine Prairie Energy Center for 2,000,000 MMBtus of natural gas storage through May 2025.

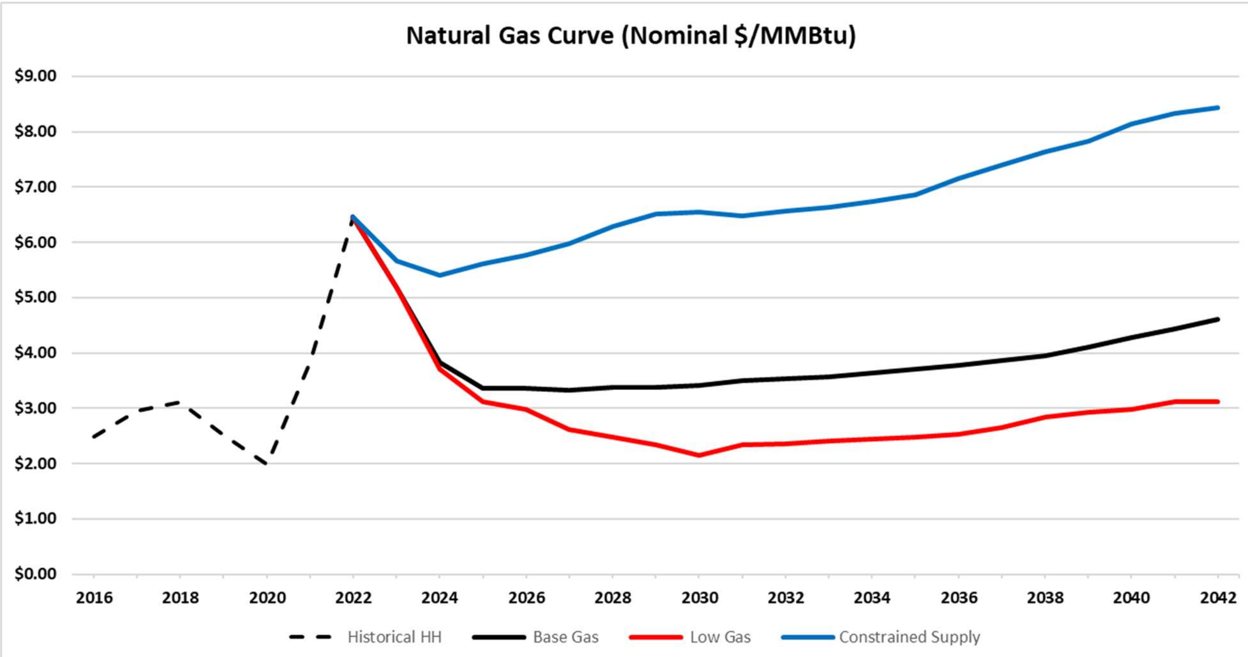
Cleco Power relied on fuel price forecasts from Filsinger Energy Partners ("FEP") to develop its natural gas forward curves.

FEP's gas price forecast is developed from the DrillingInfo (Enverus) Prodcast model. The Prodcast model produces a forecast of annual natural gas production for the United States and includes production and cost parameters for every natural gas and oil play in the United States. Oil prices are a necessary input to the model because natural gas is an associated byproduct of oil production. To develop the price forecast, FEP uses United States Energy Information Administration ("EIA") data and FEP forecasts to estimate demand for natural gas, including LNG exports. The Prodcast model was iterated using a series of Henry Hub natural gas prices, until long-term natural gas production equaled the specified natural gas demand. High and low gas price scenarios were run using sensitivities on targeted rate of return, initial production, and costs for new wells, in addition to underlying oil price sensitivities. The front end of the Henry Hub forecast is based upon the New York Mercantile Exchange ("NYMEX") forward curves before transitioning to a fundamental forecast in the mid- and long-term horizons.

[10] See https://www.eia.gov/electricity/annual/.

An illustration of the reference case curve, constrained supply, and low price sensitivities can be seen below.[11] The annual average of historical Henry Hub daily gas prices is included for reference.

Figure 4.1: Natural Gas Prices



Solid Fuel Considerations

Price projections for Cleco Power's solid fuels are based on proprietary projections of PRB coal, Illinois Basin coal, and petcoke. The forecasts include data from various consultants and existing fuel contracts for other fuels. Five years of historical price data is included in each chart for reference.

<u>PRB Coal</u>

Cleco Power uses PRB coal to generate electricity at Rodemacher 2. Due to the globally high demand for all coal types, Cleco Power is required by its coal supplier to enter into long-term coal contracts, typically for two-year terms. Due to recent constraints, there has been very little PRB coal available in the spot market. Cleco Power contracts with Wells Fargo Rail Corporation for the use of approximately 113 railcars to transport its coal from the PRB region to Rodemacher 2. Cleco Power purchased approximately 560,000 tons of coal in 2022 and has currently contracted for a minimum of 450,000 tons in 2023.

[11] The natural gas curve was supplied to Cleco Power on August 16, 2022.

Petcoke and Illinois Basin Coal

Madison 3 is fueled by petcoke and Illinois Basin coal. As with PRB coal, Illinois Basin coal has very limited spot market availability, so Cleco Power has been required by its coal providers to enter into long-term coal contracts, typically for two-year terms. Petcoke is a byproduct of the oil refinery process and is now marketed as a replacement for both coking coal and thermal (fuel) coals. However, unlike coal, ample petcoke supplies are produced by refineries each year within the Gulf Coast region. Petcoke spot purchases are typically short-term in nature, ranging from three months to one year in duration, along with occasional one-time purchases. Accordingly, Cleco Power commonly uses one-year purchase agreements for its petcoke requirements while also being utilizing spot market purchases, if necessary. For 2022, Cleco Power purchased approximately 732,000 tons of petcoke and 201,000 tons of Illinois Basin coal. For 2023, Cleco Power has contracted for 779,000 tons of petcoke and 300,000 tons of Illinois Basin coal. Louisiana waterways, including the Mississippi River and the Red River, are used to deliver both Illinois Basin coal and petcoke to Madison 3. Figure 4.2, below, shows the historical weighted average prices of Illinois Basin coal and petcoke, as well as the base price used in the reference case and the high price used in the high solid fuel sensitivity. The price includes freight delivered to Madison 3.

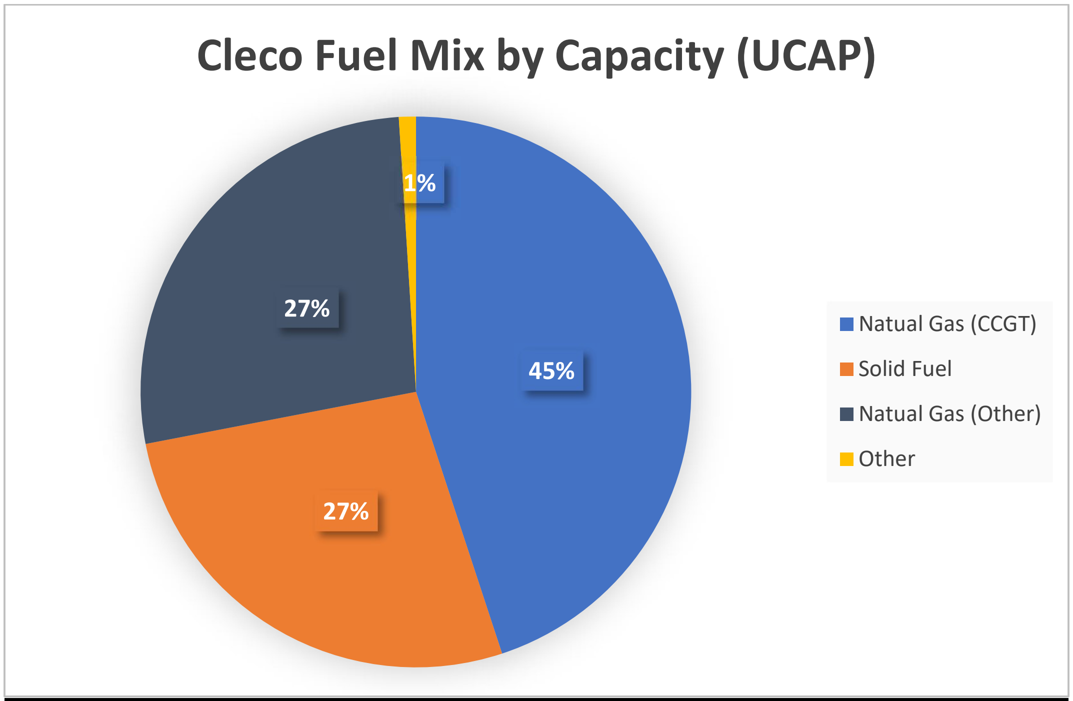
[redacted]

[redacted]

Fuel Mix

Cleco Power's 2022 EGUs and overall fuel mix by capacity is provided in Figure 4.3, below.

Figure 4.3: 2022 Fuel Mix

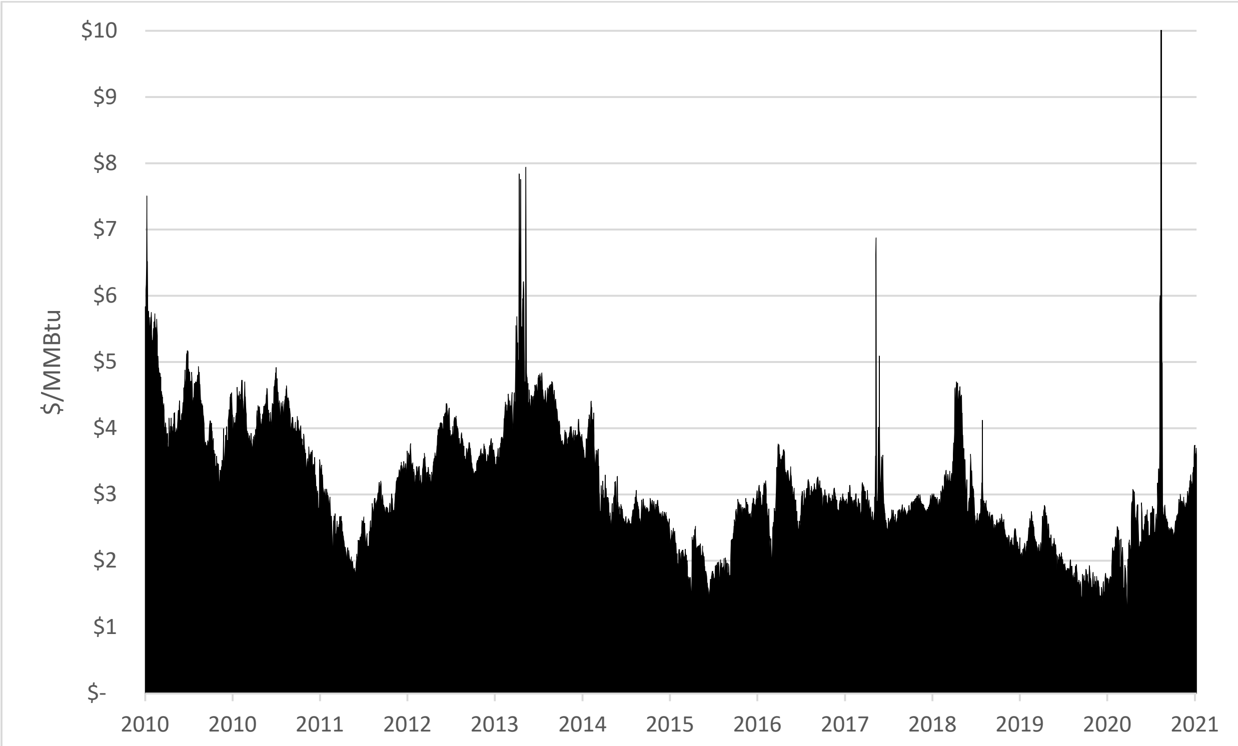


Risks

Cleco Power faces price risk in its purchases of natural gas and solid fuels, both with contracts and spot market purchases. While contracts offer some price stability, it is possible that market prices may be lower than contract prices. Conversely, opting to procure fuel at spot prices increases the likelihood of experiencing volatility in fuel procurement costs.

The level of generation from natural gas depends heavily on market prices, as is represented in the report on Henry Hub spot prices. Henry Hub spot prices have a history of being extremely volatile, as shown in Figure 4.4, below. Due to recent global events, natural gas prices spiked to $7-$9 per MMBtu, but have since fallen to approximately $2 per MMBtu.

Figure 4.4: Henry Hub Daily Natural Gas Prices



Due to the nature of coal procurement, PRB coal does not experience daily volatility like natural gas. This allows Cleco Power to be less influenced by energy market volatility.

Delivery Risk

The proper and timely delivery of fuel to Cleco Power's generating stations is subject to a number of risks which can affect the reliability of Cleco Power's EGUs and the fuel cost paid by its customers.

Delivery of natural gas requires available fuel and transportation, which depends on the successful operation of both the upstream and midstream sectors of the natural gas industry. Fuel storage and local fuel supplies can mitigate some upstream disruptions, but pipeline issues or demand spikes can make natural gas more difficult to acquire.

Cleco Power utilizes both firm transportation contracts and local natural gas storage to help mitigate delivery risk. Cleco Power also owns and operates pipeline laterals that tie Acadia and Coughlin directly to natural gas storage at the Pine Prairie Hub. This direct interconnection provides increased reliability and flexibility of supply for operations within Cleco Power's service territory.

Solid fuel plants also require available fuel and transportation. Severe weather, such as hurricanes and flooding, can have a major impact on rail and barge transportation. Cleco Power mitigates some of these risks at Rodemacher 2 and Madison 3 by storing multiple weeks' supply of fuel inventory on site.

Waste Heat – St. Mary CEC

In 2019, Cleco Power completed construction of the St. Mary CEC, a 47 MW renewable EGU, located in St. Mary Parish. The facility uses captured waste heat from the adjacent Cabot Corporation manufacturing facility to generate electricity. The waste heat is low-cost relative to other supply options, which helps reduce fuel costs for Cleco Power customers.

Section 5: Regional Transmission Development

Introduction

Cleco Power serves approximately 291,000 customers in 24 of Louisiana's 64 parishes:

Acadia
Allen
Avoyelles
Beauregard
Calcasieu
Catahoula
DeSoto
Evangeline
Grant
Iberia
Jefferson Davis
LaSalle
Natchitoches
Rapides
Red River
Sabine
St. Landry
St. Martin
St. Mary
St. Tammany
Tangipahoa
Vermilion
Vernon
Washington

Cleco Power owns approximately 12,200 miles of distribution lines operating at less than 69 kV to serve its retail and wholesale customers within Louisiana. Cleco Power also owns approximately 1,384 miles of transmission lines comprised of:

- 29 miles of 69 kV line;
- 678 miles of 138 kV line;
- 610 miles of 230 kV line; and
- 67 miles of 500 kV line.

Customers are served through 89 transmission bulk substations. Cleco Power does not own any 500 kV substations, and is only a partial owner of Entergy Louisiana, LLC's ("ELL") Webre to Wells and Hartburg to Layfield 500 kV transmission lines.

The Bulk Electric Grid

The primary goal of this section is to review and assess the overall adequacy of the interconnected bulk electric transmission system with respect to Cleco Power's first-tier neighbors, especially within the MISO South region. This assessment covers transmission expansion plans and operational characteristics that could affect electricity imports into Cleco Power's LBA. The assessment includes a review of expansion projects proposed by MISO South for Cleco Power's LBA, as well as a review of the adequacy of the bulk transmission system for electricity deliveries into Cleco Power's LBA during contingency and constrained conditions.

The regulatory obligations of electric utilities ensure that the North American transmission system is generally reliable. However, the transmission system possesses little unused capacity for market purchases of electricity. Any unused capacity is quickly committed on a first-come, first-served basis. Expansion projects aiming to increase the capacity of the transmission system for the primary purpose of maximizing the economic efficiency of wholesale electricity markets (*i.e.*, non-reliability projects) are pursued only if the economic viability of such projects is adequately demonstrated.

MISO's Resource Adequacy Explanation[12]

MISO and its stakeholders have developed a set of guiding principles for resource adequacy ("RA") to improve confidence that each MISO region will possess an adequate level of physical resources to economically serve load at all times. RA standards are set with the test of shedding firm load for a maximum of one full day within a 10-year span, known as a 1-in-10 loss of load expectation ("LOLE") standard. The guiding principles for RA are not intended to interfere with an LSE's responsibilities. LSEs, with applicable oversight by state commissions and the

[12] Information and some language for this section drawn from MISO's *MTEP 18 Book 2 – Resource Adequacy* document.

Organization of MISO States ("OMS"), are responsible for the adequacy of their resources. The guiding principles are:

1. The RA process must ensure confidence in RA outcomes in all time horizons.
2. MISO will work with stakeholders to ensure an effective and efficient RA construct with appropriate consideration of all eligible internal and external resources and resource types, as well as recognition of legal and regulatory authorities and responsibilities.
3. MISO will determine RA at the regional and zonal levels and provide appropriate regional and zonal RA transparency and awareness for multiple forward time horizons.
4. MISO will administer and update processes in a manner that provides transparency and reasonable certainty while appropriately protecting individual Market Participant ("MP") proprietary information in order to support efficient stakeholder resource and transmission investment decisions.
5. MISO's annual PRA and other processes will support multiple methods of achieving and demonstrating RA, including self-supply, bilateral contracting, and market-based acquisition.

The desired outcomes of MISO's RA guiding principles are:

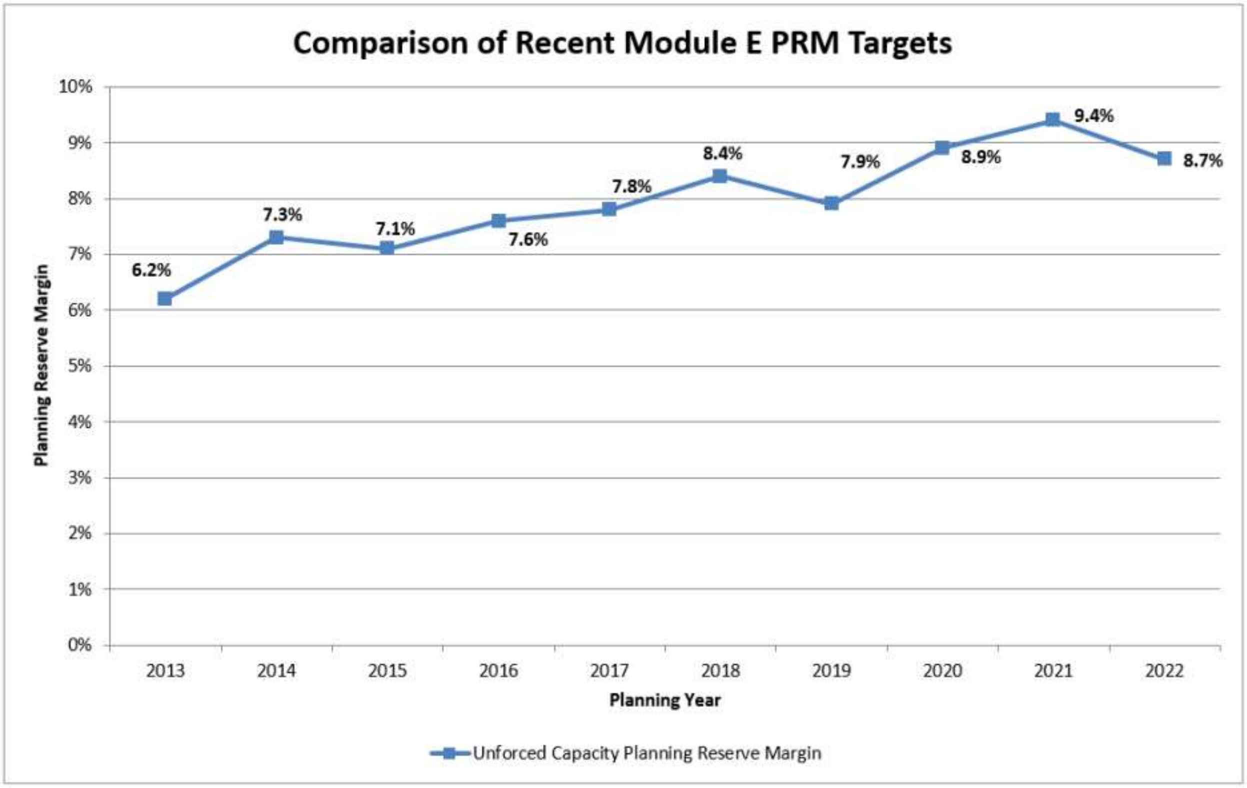
- to have confidence that RA standards will be achieved in all time horizons;
- to have confidence in MISO's RA assessments; and
- for MISO to provide sufficient transparency and market mechanisms to allow for mitigation of potential shortfalls.

<u>Planning Reserve Margin</u>

The MISO Installed Capacity Planning Reserve Margin ("PRM_{ICAP}") establishes a target for the appropriate level of installed capacity ("ICAP") to serve the MISO footprint under probable load scenarios. As directed under Module E-1 of the MISO FERC Electric Tariff (the "MISO Tariff")[13], MISO coordinates with MPs to determine the appropriate PRM_{ICAP} for the applicable planning year based on an analysis of MPs' ability to reliably serve MISO Coincident Peak Demand ("CP") for that planning year. Effectively, the PRM_{ICAP} is the capacity required in excess of MISO's peak demand. The analysis uses a LOLE study that assumes no internal transmission constraints within MISO's footprint. PRM_{ICAP} is calculated using a 1-in-10 LOLE standard. Once the PRM_{ICAP} is calculated, it is converted into a metric of unforced capacity planning reserve margin ("PRM_{UCAP}") based on forced outage rates of MISO EGUs. Figure 5.1, below, shows MISO's PRM_{UCAP} for the previous ten planning years.

[13] *See* www.misoenergy.org/legal/tariff/.

Figure 5.1: Historical MISO PRM



PRM_{UCAP} for the 2022-2023 planning year (June 1, 2022 through May 31, 2023) was 8.7 percent, while the PRM_{ICAP} was 18.3 percent. Beginning with the 2023/2024 capacity auction year, MISO incorporated seasonal reserve margin requirements:

- Summer (June, July, and August) = 7.4%
- Fall (September, October, and November) = 14.9%
- Winter (December, January, and February) = 25.5%
- Spring (March, April, and May) = 24.5%

MISO works with stakeholders participating in the Loss of Load Expectation Working Group ("LOLEWG") to develop the LOLE study, which is used to determine the congestion-free PRM_{ICAP} and PRM_{UCAP}. Deliverables for the study are based on the RA construct per Module E-1 of the MISO Tariff. The LOLE study also determines a per-unit local reliability requirement ("LRR") for each local resource zone ("LRZ"). The LRR is the amount of resources a particular area needs to meet the 1-in-10 LOLE standard without the benefits of the capacity import limit ("CIL"). The study's results are merged with the CIL, the capacity export limit ("CEL"), and wind and solar capacity credits to form the deliverables to the annual PRA.

2022-2023 Deliverables to the PRA

Planning reserve margin ("PRM") deliverables needed for the PRA include the PRM_{UCAP}, a per-unit zonal LRR, and CIL and CEL values, all of which are listed for the 2022-2023 PRA in Table 5.1, below.

Table 5.1: Deliverables to 2022-2023 PRA

	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
PRM_{UCAP}	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%
Per-Unit Zonal LRR	1.121	1.14	1.164	1.332	1.365	1.175	1.194	1.35	1.179	1.595
CIL (MW)	4,629	1,923	5,626	10,224	6,072	7,352	3,749	4,037	4,201	3,033
CEL (MW)	2,273	2,246	3,777	No Limit Found	No Limit Found	7,231	2,392	4,705	1,501	842

Zonal CIL and CEL values for each LRZ were calculated with the monitored and contingent elements reported for capacity imports and exports.

Seasonal Accreditation Construct ("SAC")

In December 2021, FERC approved MISO tariff revisions to design a RA construct that transitions from a summer-based annual construct to a seasonal construct so that MISO can better account for and mitigate reliability risks that occur throughout the year. Enhanced LOLE modeling methods are being used to better reflect resource seasonality in developing seasonal requirements. The accreditation methods were revised to reflect resource availability when MISO needs it most within seasons. The PRA process was modified to align with the seasonal approach, combined with seasonal day-ahead performance obligations to enable flexibility of seasonal operations of resources.

MISO and state regulators share responsibility for setting rules and regulations to ensure that longer-term resource planning provides electric reliability, principally through investments in transmission and generation facilities. Their rules and regulations employ both competitive markets and centralized planning, such as IRPs, to cause LSEs to invest in building resources that are forecasted to be needed to reliably serve customers in the future. LSEs share the responsibility for long-term electric reliability because they must make investment decisions in response to market incentives and regulatory requirements.

However, MISO has historically viewed RA as the responsibility of state regulators and LSEs because these entities undertake long-term supply planning for the load in the majority of MISO's footprint. State commissions consider RA when assessing the siting of generation and transmission and when setting retail electric rates. RA is an important issue when regulators review a utility proceeding that involves resource procurement, such as building a new power plant. A commission's regulatory decisions can be informed by an examination of the system's overall RA. Moreover, many state commissions require utilities and other LSEs to file IRPs to demonstrate that they are making prudent resource planning and investment decisions to maintain electric reliability for their retail customers.

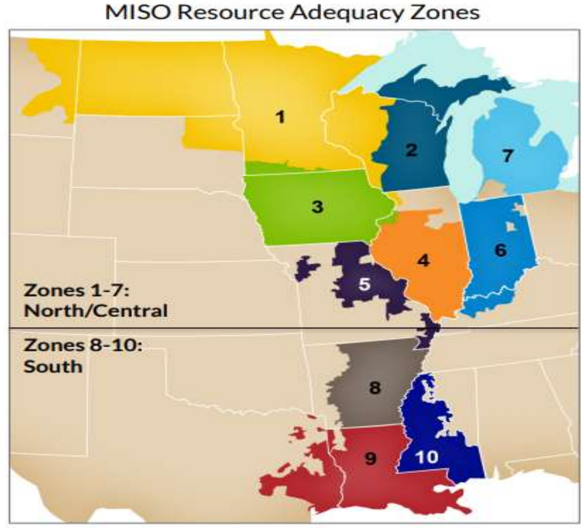
The LPSC currently has two open dockets which will impact RA in Louisiana. In LPSC Docket No. R-36263, the Commission is considering the development of a minimum physical capacity requirement. Cleco Power supports this effort, especially considering the FERC's recent rejection of a similar proposal by MISO. The Commission is also considering a possible modification of its IRP rules to remove the exemption for electric cooperatives in LPSC Docket No. R-36262. Cleco Power also supports this change in rules and maintains that electric cooperatives should be required to file IRPs. Cleco Power will comply with any rules that are implemented dockets.

The 2023/2024 PRA included the SAC methodologies. MISO is projected to have adequate capacity to meet resource adequacy requirements for PY 2023-24 at the regional, subregional, and zonal levels. Clearing prices were generally consistent across the region; however, Zone 9 showed a significant pricing deviation. This deviation is a price signal that the units with available capacity in Zone 9 are viewed as more expensive to maintain, likely due to advanced age. Typically, this type of price signal is a precursor to a lack of adequate resources in future years.

2023 PRA Results

Zone	Local Balancing Authorities	Price $/MW-Day			
		Summer	Fall	Winter	Spring
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$10.00	$15.00	$2.00	$10.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00	$15.00	$2.00	$10.00
3	ALTW, MEC, MPW	$10.00	$15.00	$2.00	$10.00
4	AMIL, CWLP, SIPC, GLH	$10.00	$15.00	$2.00	$10.00
5	AMMO, CWLD	$10.00	$15.00	$2.00	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00	$15.00	$2.00	$10.00
7	CONS, DECO	$10.00	$15.00	$2.00	$10.00
8	EAI	$10.00	$15.00	$2.00	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00	$59.21	$18.88	$10.00
10	EMBA, SME	$10.00	$15.00	$2.00	$10.00
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$10.00	$15.00	$2.00	$10.00

MISO Resource Adequacy Zones



MISO Transmission Projects – Cleco Power

Projects proposed in MISO's MTEP22 cycle are part of a continuing effort to strengthen the existing transmission network. One project was identified in Cleco Power's service territory per MISO's MTEP22 Section 4.4.3, described as Project 20163: Many Area Transmission Expansion, below.

Previous projects proposed in MISO's MTEP21 cycle that are currently under construction are also reported here. Three projects were identified in Cleco Power's service territory per MISO's MTEP21 Appendix D1-South. These projects are also described below:

Project 20163: Many Area Transmission Expansion

Project Description

Project 20163 taps the existing Fisher to Mansfield Compressor 230 kV line 8.3 miles from Fisher. From the tap point, Cleco Power will build two new 2.8-mile 230 kV lines to a new substation named Belmont that is tapped into the Pelican to Loring and Loring to Many 138 kV lines. At Belmont substation, Cleco Power will add a 230/138 kV 300 MVA autotransformer. The project's estimated cost is $39.2 million, and its expected in-service date is June 1, 2025.

Project Need

In 2025, a P6 contingency on Many to Fisher 138 kV line followed by a contingency on Carroll to Red River 138 kV line causes an overload greater than 125% on South Shreveport to Wallace Lake 138 kV line. Voltage violations also exist for this contingency. Load shed is the only mitigation for this P6 contingency. With projected industrial load growth in this area, this project has been modified to account for the additional load.

Cont. Type	Limiting Element	Rating (MVA)	Pre-Project Loading (%)	Post-Project Loading (%)
P6	South Shreveport – Wallace Lake 138 kV	188	133	6
P6	Wallace Lake – International Paper 138 kV	188	111	6
P6	Mansfield – Pelican 138 kV	143	112	22
P6	Pelican – Loring 138 kV	143	97	N/A

Cont. Type	Limiting Element	Rating (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	Many 138 kV	0.9	0.48	1.035
P6	Loring138 kV	0.9	0.48	1.032
P6	Pelican 138 kV	0.9	0.56	1.016
P6	Mansfield 138 kV	0.9	0.60	1.006
P6	International Paper 138 kV	0.9	0.80	0.991

Alternatives Considered

Several alternatives were considered for this area. With additional load growth, this project was changed to the current solution, which is the least cost, most reliable solution.

Project 13874: Flagon Substation

Project Description

Project 13874 builds a new 230 kV substation tapped into the Donahue to Sherwood 230 kV line and uses the distribution in the area to move 16 MW from the Beaver Creek substation. The project's estimated cost is $8.1 million, and its expected in-service date is August 15, 2023.

Project Need

The North American Electric Reliability Corporation ("NERC") defined P7 contingencies on Donahue-Beaver Creek 138 kV line 1 and Donahue-Beaver Creek 138 kV line 2 create low voltage, shown in the table below, at the Beaver Creek 138 kV substation in summer peak models. Building the Flagon Substation will allow more distribution flexibility in the area and reduce the load at Beaver Creek by 16 MW. This will eliminate the low voltage caused by the P7 contingencies.

Contingency Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P7	Beaver Creek 138 kV	0.90	0.88	1.02

Alternatives Considered

Cleco Power considered rebuilding the Beaver Creek to Donahue lines to be on separate structures. This option was not selected because the Flagon substation project fixed both transmission and distribution issues.

Cost Allocation

Project 13874 is a baseline reliability project, which is not eligible for regional cost sharing.

Project 21169: Bayou Sale Capacitor Move

Project Description

Project 21169 moves the existing 19.2 MVAR capacitor bank at the Bayou Sale 138 kV substation to the Pelican 138 kV substation. The project's estimated cost is $700,000, and its expected in-service date is June 15, 2023.

Project Need

NERC defined P6 contingences on the Carroll-Red River 138 kV line and on the Many-Fisher 138 kV line as causing low voltage issues and potential overloads on the South Shreveport-Wallace Lake 138 kV line as shown in the table, below.

Cont. Type	Limiting Element	Voltage Limit (pu)	Pre-Project Voltage (pu)	Post-Project Voltage (pu)
P6	South Shreveport-Wallace Lake 138 kV	.90	.87	.98

Alternatives Considered

Cleco Power did not consider other alternatives because this project used existing equipment which was no longer needed in south Louisiana to fix issues in north Louisiana.

Cost Allocation

Project 21169 is a baseline reliability project, which is not eligible for regional cost sharing.

Project 21207: Slidell Airport Line Move

Project Description

The Slidell regional airport expansion requires the relocation of the North Slidell-Talisheek 230 kV line and the North Slidell-Cane Bayou 230 kV line. The project's estimated cost is $9.8 million, and its expected in-service date is June 1, 2023.

Potential Congestion Problems

Cleco Power actively participates in MISO's committees. Typically, Cleco Power's system is *not* identified as one of the leading flow gates for congestion. Potential congestion in MISO South is currently unknown due to systematic change in future generation resources, MISO's unprecedented generation queue, and unknown retirement targets for generators.

Cleco Power Transmission

Cleco Power's transmission strategy department performed a study of NERC transmission planning standards called the TPL-001-4 Assessment, also known as NERC Table 1.

The following projects were identified as potential transmission system issues over the next ten years and are either currently under construction, have been approved for construction, or have been completed and placed in service:

Bayou Vista to Segura 230 kV Line

This project was constructed 26 miles of 230 kV line from the Segura Substation to a new substation at Teche Power Station, which is called Caneland Substation. This project also included 22 miles of 230 kV line from Caneland Substation to Bayou Vista Substation. Caneland Substation is a three terminal 230 kV ring, expandable to a breaker and a half configuration, and a 500 MVA 230/138 kV autotransformer was installed at Caneland Substation. A short 138 kV section of bus connects the Caneland and Teche substations, with the 138 kV Teche end receiving an additional breaker and bay. The 230 kV ring buses at the Segura Substation and the Bayou Vista Substation were also built out. The Segura to Caneland 230 kV line was placed in service in August 2021. The 230 kV line from Caneland to Bayou Vista was put in service in December 2021.

Coughlin to Manuel Reactor

This project relocated the series reactor from Wells to Manuel and was put in service with a bypass breaker at the Manuel Substation on the Coughlin to Manuel Line Terminal. This helps reduce overloads under contingencies and balance the power across the 138 kV and 230 kV lines flowing south out of Coughlin. This project was placed in service in December 2021.

Sellers Road Expansion

This project added a 138 kV, four terminal substation interconnected to the existing Sellers Road 230 kV substation by a 500 MVA autotransformer. On the 138 kV side this substation taps the Habetz to Flanders 138 kV line. Additionally, ELL built a 138 kV line at 230 kV specifications from Sellers Road to Conrad (near Leblanc). This was a joint project between Cleco Power and Entergy Louisiana, LLC. This project was put in service in August 2022.

Flagon Substation

This project constructed a new 230 kV substation, called Flagon, by tapping the Donahue to Sherwood 230 kV transmission line. The Flagon station serves 20 MWs of distribution load, transferred from Beaver Creek station. This eliminated a P7 contingency, the loss of both Beaver Creek to Donahue 138 kV lines, #1 and #2, and resulted in low voltage at Beaver Creek. This project was completed in December 2022.

Negreet New Substation

This project will add a 69/34.5 kV transformer to Negreet substation, and a portion of Cleco Power's distribution load out of Many will be moved onto this substation. This will provide improved reliability to the local distribution load. This project is scheduled to be completed in third quarter of 2023.

Relocate Bayou Sale Capacitor Bank

This project will relocate the existing Bayou Sale capacitor bank to the Mansfield station. This will mitigate voltage issues seen for P6 double contingencies in the area and act as an interim solution until a larger scale transmission solution can be built. This project is projected to be in service in the third quarter of 2023.

Long-Range Transmission Planning ("LRTP")

MISO is tasked with delivering safe, reliable, and cost-effective power across fifteen states and the Canadian province of Manitoba. Within MISO's diverse regional footprint, utility members are making plans, committing to near- and long-term retirements and investments, and announcing increasingly advanced decarbonization goals. Although MISO's role is to remain policy- and resource-agnostic, a clear fleet transition is underway that has implications for system operations.

As the fleet transforms, the need to maintain reliable and efficient system operations is driving what MISO refers to as a regional "Reliability Imperative." A key element to MISO's response to the Reliability Imperative is the LRTP initiative.

LRTP's goal is to assess MISO's future transmission needs in concert with utility and state plans on where to site and build new generation resources. There is an urgent need for LRTP as customer preferences, decarbonization goals, and economics are accelerating fleet transition.

One tool at MISO's disposal is the use of forward-looking planning scenarios to provide outlooks of the future. These future planning scenarios establish different ranges of economic, policy, and technological possibilities, such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices, and generation capital cost over a twenty-year period. This information is used to model a capacity expansion, which forecasts the fleet mix that meets MISO's PRM at the lowest cost while adhering to policy objectives. Using the range of resource generation modeled, MISO will then apply the future planning scenarios' expansion results to the development of transmission plans, the LRTP, and other MISO initiatives that ensure continued reliable and economic energy delivery.

The MISO Board approved LRTP Tranche 1 (of several tranches) on July 25, 2022. Cleco Power will be a part of Tranche 3, which will focus purely on MISO South (Zones 8-10). No projects have been proposed at this time, but Cleco Power will work with both MISO and the LPSC to ensure the proposed projects deliver the greatest possible benefits. One of the main drivers in getting the right transmission built is proper siting of future generation resources. This is key not only for Cleco Power as new additions and retirements occur, but also for the entire MISO South region. These discussions are underway, with project proposals starting in the summer of 2023 and tentatively receiving MISO Board's approval in December 2024.

Cleco Power is closely monitoring the MISO LRTP process and awaiting the Future 2A models to evaluate future needs of the transmission system based on the assumptions in these models.

Section 6: Environmental Considerations

Generation resource projects are typically subject to federal, state, and local laws and regulations governing environmental protection. Environmental permits for these projects must often be obtained to comply with applicable environmental laws and regulations. These projects must also consider new legislation, administrative actions, and judicial interpretations with respect to environmental and economic impacts.

Air Quality

Introduction

Louisiana regulates airborne emissions from EGUs through the air quality regulations of the Louisiana Department of Environmental Quality ("LDEQ"). The LDEQ has established standards of performance and requires permits for sources of certain types of emissions in Louisiana.

Greenhouse Gas Emissions

Greenhouse gases ("GHG") and their role in climate change have been the focus of study and legal action, including proposed federal legislation, final and proposed rulemakings, and civil actions. Congress has attempted to craft specific legislation that would reduce GHG emissions by electric utilities, industrial facilities, and other manufacturing sectors of the economy. While Congressional efforts have not yet resulted in new legislation, federal GHG legislation may eventually be enacted.

In 2009, in a ruling known as the "Endangerment Finding," the EPA found that GHGs threaten public health and welfare. The GHGs identified in the ruling were CO2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The Endangerment Finding requires new or modified EGUs that increase GHG emissions beyond a threshold amount to be subject to New Source Review ("NSR") requirements, which, under certain circumstances, could require the adoption of best available control technology.

The EPA, under Clean Air Act Section 111 ("CAA 111"), finalized New Source Performance Standards ("NSPS") for CO2 emissions at new, modified, and reconstructed EGUs. NSPS was formally titled "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," and was finalized in 2015. CAA 111 defines "standard of performance" as a standard for CO2 emissions which reflects the degree of emission limitation achievable through the application of the best system of emission reduction ("BSER"). When determining BSER, the EPA considers emission reduction costs, energy requirements, and non-air environmental and health impacts. Emission limits for the rule are listed in Table 6.1, below.

Table 6.1: NSPS for New Boilers and New/Reconstructed CTs

EGU Type	BSER	Emission Limit
Coal Fired Boilers	Supercritical pulverized coal ("SCPC") design with partial	1,400 lbs CO2/MWh

	carbon/capture/storage or co-firing with gas	
Base-Loaded CTs	Natural gas combined cycle technology	1,000 lbs CO_2/MWh
Non-Base-Loaded CTs	Natural gas simple cycle technology	120 lbs CO_2/mmBtu

CAA 111 subsection B ("CAA 111(b)") further requires the EPA to propose emission performance standards for modified EGUs, where modifications increased CO_2 emissions, and for reconstructed EGUs. An EGU is considered modified if a physical change or change in operation method results in an increase in its hourly CO_2 emission rate, whereas an EGU is considered reconstructed if components are replaced to such an extent that the capital cost of new components exceeds 50% of the estimated cost of a newly-built EGU. Affected EGUs include boilers, integrated gasification combined cycle ("IGCC") EGUs, and CTs. The rule determines the BSER and corresponding emission limits, which are detailed in Table 6.2, below. As part of its determination of BSER, the EPA proposed two alternative compliance scenarios for modified boilers and IGCC EGUs.

Table 6.2: NSPS CAA 111(b) For Modified/Reconstructed Boilers

EGU Type	BSER	Emission Limit
Modified Boilers and IGCC EGUs making large modifications	Best historical annual CO_2 emission rate since 2002	Heat input > 2,000 mmBtu/hr = 1,800 lbs CO_2/MWh; Heat input <= 2,000 mmBtu/hr = 2,000 lbs CO_2/MWh
Reconstructed Boilers and IGCC Heat Input > 2,000 mmBtu/hr	Super critical steam generation technology at affected source	1,800 lbs CO_2/MWh
Reconstructed Boilers and IGCC Heat Input < 2,000 mmBtu/hr	Most efficient generation technology at affected source	2,000 lbs CO_2/MWh

In March 2017, the EPA was ordered to review the GHG NSPS and, if appropriate, propose a rule to suspend, revise, or rescind the rule. In April 2017, the EPA announced that it was initiating proceedings to review the GHG NSPS. Consolidated petitions for review of the GHG NSPS have been held in abeyance since April 2017 at the EPA's request while the agency reviewed the rule. In September 2018, the EPA submitted a proposed rule entitled "Review of the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units" to the White House Office of Management and Budget ("OMB") for interagency review. Although the NSPS rule remains in effect, until the EPA has completed its review of NSPS and any resulting rulemaking, future regulatory requirements for new, reconstructed, or modified sources are uncertain.

Additionally, the EPA finalized CO2 emission guidelines for EGUs that were in service or began construction on or before January 8, 2014. The guidelines, formerly titled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" and more commonly referred to as the Clean Power Plan ("CPP"), required states to choose between a specific state CO2 emission rate or state a mass-based CO2 emission limit that reflects BSER. In its final rule, the EPA defined BSER for reducing CO2 emissions at existing EGUs through three "building blocks." The building blocks for both compliance scenarios are detailed in Table 6.3, below, and the resulting national emission rate standards are shown Table 6.4, below.

Table 6.3: CPP BSER Building Blocks

	Building Block 1	Building Block 2	Building Block 3
Description	Efficiency improvement at coal-fired EGUs	Revert dispatch to EGUs with lower emissions	Increase dispatch of zero emission sources
Proposed Target	4.3% improvement in heat rate of coal-fired EGUs	Dispatch CCGT EGUs at 75% capacity factor	Increase incremental zero emission generation annually through 2029

Table 6.4: National Performance Rate for Existing Eligible Units

Category	Interim Rate (2022-2030)	Final Rate 2030+
Fossil Fuel Fired Boilers	1,534 CO2 lbs/MWh	1,305 CO2 lbs/MWh
Stationary CTs	832 CO2 lbs/MWh	771 CO2 lbs/MWh

State CO2 emission rates allowed under the CPP, taking the three building blocks into consideration, are shown in Table 6.5, below. The final rule requires meeting both an interim and final emission rate over the compliance period. The final goal applies to all years following the completion of the compliance period. Louisiana's final goal, 1,121 lbs CO2/MWh is well below its current CO2 emission rate, which is calculated using gross MWh to be approximately 1,400 lbs CO2/MWh.

Table 6.5: CPP Compliance Goals for Louisiana

	Interim Emission Goal (2022-2029)	Final Emission Goal (2030+)
Rate-Based Goal	1,293 lbs CO2/MWh	1,121 lbs CO2/MWh
Mass-Based Goal	314,482,512 tons/yr	70,854,046 tons/yr

On October 23, 2015, twenty-four states, attorneys general, and other governmental entities filed the first petition for review of the CPP.[14] The Supreme Court stayed the CPP on February 9, 2016 and indicated it would remain stayed until the lower court made its decision and until any subsequent challenge to the rule in the higher court was decided.

On April 4, 2017, the EPA announced in the Federal Register that it was reviewing the CPP, and, if appropriate, it would initiate proceedings to suspend, revise, or rescind it. Following this, the U.S. Court of Appeals for the District of Columbia Circuit, in an April 28, 2017 order, delayed for 60 days litigation over the EPA's CPP for existing power plants.

On October 16, 2017, the EPA published a proposed rule that would repeal the CPP, titled Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.[15]

On August 31, 2018, the EPA published a proposed rule to replace the CPP.[16] Titled *Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review*, the proposal is referred to as the Affordable Clean Energy ("ACE") rule.

ACE would revise emission guidelines to replace the CPP and inform the development of state plans to reduce GHG emissions from certain EGUs. In the guidelines, the EPA proposed to determine that heat rate improvement ("HRI") measures at the source are the BSER for existing fossil-fuel units while focusing the detail of the rule on coal-fired EGUs. The proposal exempted both natural gas combined cycle and IGCC units from regulation.

On July 8, 2019, the EPA published the final rule, titled *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*. The final rule greatly resembled the

[14] S*ee West Virginia et al v. EPA et al*, No. 15-1363 (D.C. Cir.).
[15] *See* 82 Fed. Reg. 48,035.
[16] *See* 83 Fed. Reg. 44,746.

proposed rule. State agencies, including LDEQ, are required to set performance standards for each affected unit and submit the implementation plan to the EPA for approval within three years after the date of publication in the Federal Register.

When determining state standards of performance, LDEQ must consider the cost of applying the technology along with other site-specific factors, including remaining useful life of the unit. For example, the EPA indicated in the preamble of the final ACE rule that, while steam turbine blade path upgrade and economizer replacement are likely to be highly effective HRI technologies, they also have the most potential to trigger NSR requirements. Resulting NSR requirements, including analysis, permitting, and capital investments, will greatly increase the cost of implementing those HRI technologies. The EPA further indicated that, as a result, states would be more likely to determine that those two technologies are not cost-effective when analyzing "other factors" in determining an individual facility's standard of performance. States could determine that all six of the listed technologies, or none of the technologies, are applicable to an individual unit. In February 2020, LDEQ sent information requests ("ICRs") to Cleco Power asking for an evaluation of the HRI candidate technologies for BSER at Rodemacher 2, Madison 3, and Dolet Hills Power Station. Due to the April 2020 announcement that Dolet Hills Power Station would retire and cease operation before the compliance deadline set forth in the federal ACE rule, the ICRs were only completed for the Rodemacher 2 and Madison 3 units. The documented Cleco Power responses to the ICRs were provided to LDEQ in September 2020. LDEQ has not yet responded to Cleco Power's submittals.

On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded ACE to the EPA. The court held that the EPA incorrectly found that the Clean Air Act required that BSER must be narrowly viewed to apply at and to the individual source. The court found the statutory language ambiguous and capable of a broader reading. On February 22, 2021, the U.S. Court of Appeals for the D.C. Circuit granted the EPA's unopposed motion for a partial stay of the issuance of the mandate on vacating the repeal of the CPP and on March 5, 2021, the U.S. Court of Appeals for the D.C. Circuit issued the partial mandate effectuating the court's vacatur of the ACE Rule.

The United States Supreme Court granted four petitions for certiorari for review of the decision by the D.C. Court of Appeals to vacate/remand ACE with the lead case *West Virginia v. EPA*. The petitioners asked the Court to reinstate ACE. On June 30, 2022, the United States Supreme Court issued its opinion in *West Virginia v. EPA*, which was a case concerning the scope of EPA's authority to control GHG emissions from existing power plants under Section 111(d) of the Clean Air Act. Siding with West Virginia, and other aligned parties, the Supreme Court held that the generation shifting approach in the CPP exceeded the powers granted to EPA by Congress. The Court determined that this type of regulation is not authorized by Clean Air Act Section 111(d) and is a "major question" that requires a clear congressional authorization to the EPA. However, the Court did not decide whether the EPA may only adopt measures applied at the individual source—the basis for the ACE Rule. The Supreme Court returned the case to the lower court.

This opinion by the Supreme Court plainly restricts the application of generation shifting to craft GHG emission limits as was done in the CPP.

While currently there is not any federal regulation of GHG emissions from existing generating units, the Fall 2022 Unified Agenda of Regulatory Actions from OMB indicated that EPA is working on a new set of emission guidelines for states to follow in submitting state plans to establish and implement standards of performance for GHG emissions from existing fossil-fuel fired EGUs. Recently, on May 23, 2023, the EPA issued a proposed rule and CAA 111 intended to reduce CO2 emission at fossil-fuel fired EGUs. Under the proposed rule, coal-fired EGUs would be required to install carbon capture and sequestration technology by 2034 to capture 90% of CO2 emissions. This rule would repeal the ACE Rule. Cleco Power is still studying this newly-issued rule.[17] It is anticipated that the EPA will issue a final rule in 2024.

Mercury and Air Toxics Standards

Under its Mercury and Air Toxics Standards ("MATS") rule, the EPA established standards of performance for emissions of mercury, non-mercury metals, and acid gases from existing coal and oil-fired EGUs. The standards, which require the application of maximum achievable control technology or equivalent, were implemented under Section 112 of the Clean Air Act. Affected EGUs must have complied with the final MATS rule by April 16, 2015 or cease operations. Emission limits under the rule are detailed in Table 6.6, below. Cleco Power has installed the emission controls required to meet its required limits.

In May 2020, the EPA published a rule rescinding an April 25, 2016 finding that had indicated that it was appropriate and necessary to regulate hazardous air pollutants ("HAP") emitted from coal and oil fired EGUs. However, the EPA also concluded that its determination does not remove coal and oil fired EGUs from the list of affected source categories under the Clean Air Act National Emission Standards for Hazardous Air Pollutants and thus does not affect the status of MATS. Also, the Final Rule concluded that the results of EPA's periodic residual risk and technology assessment indicated that HAP emissions from the source category are acceptable and therefore that no revisions should be made to the MATS emission standards.

On March 6, 2023, the EPA published a rule that reinstated its April 25, 2016 finding that it is appropriate and necessary to regulate HAP from coal and oil fired electric generating units via MATS. The EPA also conducted a review of its May 2020 risk and technology determination not to revise the MATS emission standards and released on April 5, 2023, a proposal to revise requirements under MATS.

[17] *See* Proposed Rule: New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired EGUs.

Table 6.6: MATS Emission Limits

Source Category	Particulate Matter (lbs/mmBtu)	Hydrochloric Acid (lbs/mmBtu)	Mercury (lbs/TBtu)
Virgin Coal	0.3	0.002	1.2
Low-Rank Virgin Coal (lignite)	0.3	0.002	4.0

Air Transport – Clean Air Interstate Rule and Cross-State Air Pollution Rule

Air transport rules are put into place as a Clean Air Act requirement to prohibit emissions sources within a state from emitting amounts of pollutants that will contribute significantly to nonattainment of the ozone national ambient air quality standard ("NAAQS") or interfere with maintenance of the ozone NAAQS in another state.

In 2011, the EPA promulgated the Cross-State Air Pollution Rule ("CSAPR") to replace the Clean Air Interstate Rule ("CAIR"). While both rules require states to address the interstate transmission of pollutants and are built around an allowance trading program, the CSAPR allowance program is not as flexible as the CAIR program. To reduce the risk of having too few allowances to comply with CSAPR, Cleco Power chose to reduce emissions at some of its EGUs to go along with allowances allocated by the federal and state environmental regulatory agencies.

In Louisiana, CSAPR only addresses seasonal NOx emissions. SNCR systems were installed at two Cleco Power EGUs to reduce NOx emissions and corresponding allowance requirements. NOx allowances for each Cleco Power EGU and equipment upgrades for each Cleco Power EGU are listed in Table 6.7, below.

Table 6.7: CSAPR NOx Allowances and Upgrades

Plant	Unit	NOx Allowances	Equipment Upgrades
Acadia	CT 11	26	
Acadia	CT 12	28	
Brame	Nesbitt 1	205	
Brame	Rodemacher 2	262	SNCR
Brame	Madison 3 Boiler 1	318	

Brame	Madison 3 Boiler 2	339	
Dolet Hills	1	614	SNCR
Teche	3	374	
Teche	4	1	
Coughlin	6	120	
Coughlin	7-1	79	
Coughlin	7-2	66	

Under CSAPR, affected sources in Louisiana were granted an annual emission budget aggregate NOx allowance allocation of 18,639 tons for 2017, with a variability limit of 3,914 tons. If state emissions exceed the state and variability limits, the EPA determines responsible sources and calculates a penalty set forth under the rule. Sources in violation of their limits are required to place two allowances per ton in an account for emissions beyond their initial allocation and their share of the variability limit. If penalized sources fail to place sufficient allowances into their respective accounts, the EPA may bring further action.

On October 26, 2016, the EPA finalized an update to CSAPR. On September 13, 2019, the U.S. Court of Appeals for the D.C. Circuit remanded the CSAPR Update to the EPA to address the court's holding that the rule unlawfully allows significant contribution to continue beyond downwind attainment deadlines. On March 15, 2021, the EPA finalized the Revised Cross-State Air Pollution Rule Update. Starting in the 2021 ozone season, the rule required additional emissions reductions of NOx emissions from power plants in twelve states, including Louisiana. As with previous versions of CSAPR, the addressing of interstate transmission of pollutants is built around an allowance trading program with allocation of unit allowances coming from the respective State emission budget for existing units.

Cleco Power has complied with the CSAPR seasonal NOx emission requirements since May 2015.

On February 13, 2023, the EPA published the final rule disapproving interstate transport state implementation plans ("SIP") submissions for the 2015 8-hour ozone NAAQS for nineteen states, including Texas and Louisiana. Subsequently, on March 15, 2023, the EPA released the Federal "Good Neighbor Plan" for the 2015 NAAQS. This version of CSAPR is also built around an allowance trading program implemented during the May-September 2023 ozone season. The program differs from previous CSAPR programs in that instead of establishing state emissions budgets and unit allowance allocations for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet that are unknown at the time of the rulemaking, the EPA is revising the trading program regulations to include a dynamic budgeting procedure from which the allocation of allowances will take place.

The EPA is establishing preset ozone season NOx emissions budgets for each ozone season from 2023 through 2029. These budgets serve as floors and may be supplanted in years 2026-2029 by a dynamic budget that the EPA calculates for any annual control period, using more recent information, if that dynamic budget yields a higher level of allowable emissions.

This version of CSAPR focuses on maintaining a degree of control stringency over time, thus improving emissions performance at individual units and offering a necessary measure of assurance that NOx pollution controls will be operated throughout each ozone season and with proper optimization of controls-operation as needed to meet expected reduction of emissions. The emissions trading program state budget stringency will not only reflect the continued operation of controls and optimization of existing controls but will also reflect the retrofit of post-combustion controls at certain existing units that will be phased in over two annual ozone seasons (*i.e.*, 2026-2027).

The EPA indicates in the CSAPR rule preamble that the operation of retrofitted post-combustion controls in years 2026-2027 is not a requirement, but rather is expected to take place since the preset state emission budgets were crafted with the expectation of the operation of the controls at certain units.

The EPA will calculate emissions budgets for control periods in 2026 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2024 ozone season and following seasons (*e.g.*, for 2026, data from periods through 2024; for 2027, data from periods through 2025; etc.). Through the 2029 control period, the dynamically determined budgets will apply only if they are higher than preset budgets established in the rule. Budgets for 2030 and beyond will be determined by the EPA based on then-available information.

Table 6.8, below, reveals the preset Louisiana emission budgets for years 2023-2029. The budgets for years 2026-2027 reflect the post combustion controls retrofits along with other expected fleet changes such as existing unit retirements. Table 6.9 reveals the post combustion controls retrofits that the EPA expects for certain Cleco Power units.

Table 6.8: Present Louisiana Emissions Budget for Years 2023-2029

Year	Louisiana Emissions Budget – Tons NOx
2023	9363
2024	9363

2025	9107
2026	6370
2027	3792
2028	3792
2029	3639
2030 and beyond	TBD

Table 6.9: Needed Retrofits for Existing Units

Unit	Expected Post Combustion Retrofit Control
Rodemacher II	Selective Catalytic Reduction (SCR)
Nesbitt I	Selective Catalytic Reduction (SCR)
Teche 3	Selective Catalytic Reduction (SCR)

The allocation of unit allowances from the State budgets for years 2023-2025 was presented in the CSAPR rule technical support-documents with the allowances for years 2026 and beyond yet to be determined. Table 6.10 shows the NOx allowance allocations for Cleco Power units for years 2023-2030.

Table 6.10: Cleco Power's NOx allowances through 2025

Generating Unit	Allowance Allocation 2023	Allowance Allocation 2024	Allowance Allocation 2025
Acadia Power Station Unit 1	26	26	26
Acadia Power Station Unit 1	24	24	24
Brame Energy Center Nesbitt 1	177	149	147

Brame Energy Center Rodemacher Power Station 2	219	185	183
Brame Energy Center Madison 3-1	192	193	193
Brame Energy Center Madison 3-2	190	190	190
Coughlin Power Station 6-1	120	120	120
Coughlin Power Station 7-1	79	79	79
Coughlin Power Station 7-2	68	68	68
Teche Power Station Teche 3	291	245	243
Teche Power Station Teche 4	0	0	0

On May 1, 2023, the U.S. Court of Appeals for the Fifth Circuit granted motions to stay the EPA's disapproval of Texas's and Louisiana's interstate transport SIPs for the 2015 ozone national ambient air quality standards pending review. The EPA cannot finalize the federal implementation plan until the Louisiana SIP has been disapproved. As a result, Louisiana will continue to comply with the Revised Cross-State Air Pollution Rule Update.

National Ambient Air Quality Standards – SO2, Ozone, NO2, and PM.

As part of its periodic adequacy reevaluation of the NAAQS for protecting human health, the EPA adopted rules that strengthen the NAAQS for sulfur dioxide ("SO2"), ozone and nitrogen dioxide ("NO2").

In June 2010, the existing daily and annual average SO2 emission limits (140 parts per billion ("ppb") and 30 ppb, respectively) were replaced with a more stringent hourly standard (75 ppb). The updated standard allowed the use of either ambient monitors or ambient air modeling to determine compliance for the first time.

Designations of all areas, including those areas containing Cleco Power EGUs, were determined through the guidance of the Data Requirement rule, which required that non-monitored emission sources either install monitors by 2017 and accumulate data for a three-year period or complete emission modeling by 2017. The procedural schedule for the Data Requirement rule and the designation process for those sources are detailed in Table 6.11, below.

Table 6.11: SO2 NAAQS Compliance Schedule

Completion Date	Task
June 2015	LDEQ determines if modeling or monitoring is to be applied
January 2016	Modeling protocol submitted by LDEQ to EPA
June 2016	Monitoring plan submitted by LDEQ to EPA
January 2017	Monitors are deployed and operational
January 2017	Modeling analyses submitted to EPA along with non-attainment boundaries, if appropriate
December 2017	EPA issues final designations for modeling areas
August 2019	SIP demonstrations submitted to EPA for modeled areas designated as non-attainment in December 2017
May 2020	2020 LDEQ certifies monitoring data completed in 2019 and submits designation proposal to EPA
December 2020	Final designation issued by EPA for monitored areas
August 2022	SIP demonstrations submitted to EPA for monitored areas designated non-attainment in December 2020

The areas of Cleco Power's Dolet Hills Power Station and Brame were demonstrated to comply with the standard through dispersion modeling. When all third-round designations for Louisiana were formally published by the EPA in January 2018, all Cleco Power areas were listed as either unclassifiable-attainment (complying with the NAAQS standard) or unclassifiable.

In June 2018, the EPA proposed a rule to retain the current primary SO2 NAAQS standard at 75 ppb after completion of the required periodic review of the SO2 NAAQS. On March 18, 2019, the EPA published a final rule retaining the 75 ppb standard.

In October 2015, the EPA, after completion of its five-year review of the ozone NAAQS, published a final rule revising the standard. The final primary standard was lowered from 75 ppb to 70 ppb. The secondary standard was set at 70 ppb. In June 2018, the EPA published a final rule listing area designations with respect to the 2015 primary and secondary national ambient air quality standards for ozone. All Louisiana parishes were listed as attainment/unclassifiable (complying with the NAAQS standard).

On December 23, 2020, the EPA issued a final rule to retain the current primary and secondary national ambient air quality standards for ozone. After considering the currently available scientific evidence, quantitative and policy analyses, advice from the EPA's Clean Air Scientific Advisory Committee ("CASAC"), and public comments on the proposed decision, the Agency concluded that the existing primary standard of 70 ppb to be requisite to protect public health with an adequate margin of safety and should be retained without revision.

In April 2010, the revised primary NAAQS for NO2 came into effect. The EPA established a new one-hour emission standard of 100 ppb to supplement the existing annual standard, along with requirements for an NO2 monitoring network focused on roadways. States were required to have monitors in operation by January 1, 2013, after which they were given three years to collect air quality data to determine compliance. However, in December 2016, the EPA released a final rule that eliminated the requirement in the 2010 NO2 national ambient air quality standards for near-road monitoring stations in areas with populations between 500,000 and 1,000,000.

The EPA disseminated initial NO2 area designations in the first quarter of 2012. All areas across the country were designated unclassifiable attainment. In April 2018, the EPA, after completing the five-year review of the NAAQS, published a final rule that retained without revision the 100 ppb standard.

In January 2013, the EPA published its final rule changing the national ambient air quality standards for particulate matter ("PM"). The final rule revised the primary annual standard for fine PM ("PM2.5"), lowering the standard to 12 micrograms per cubic meter ("mg/m3"). Other PM standards were retained. All Cleco Power service areas complying with the standard. On January 27, 2023, the EPA published in the Federal Register a proposed rule to change the requirements for PM2.5 NAAQS. Until the EPA finalizes a new regulation, the requirements cannot be determined.

Regional Haze

Louisiana is currently focusing on regional haze planning activities in accordance with the requirements of the 1999 Regional Haze Rule, which was amended in July 2005 and again in January 2017. The objective of the Regional Haze Rule is to reduce the impact of pollutants on visibility in Class 1 areas (*e.g.*, national parks and wilderness areas). The rule requires states to develop policies to reduce visibility-impairing pollutants so that Class 1 areas will have the equivalent of natural visibility conditions by 2064. For Class 1 areas located in Louisiana and surrounding states, compliance policies will address both human and natural sources of haze-forming pollutants, document visibility conditions, and recommend appropriate strategies to meet long-term visibility goals.

Compliance with the rule for the first implementation period required Louisiana to develop a SIP that extended to 2018. There are several requirements the SIP must meet to demonstrate the required reasonable progress trend in the plan, including emission reductions through the required application of best available retrofit technology ("BART") at certain emission sources, when warranted.

The Regional Haze regulations require certain sources of fine particulate, SO2 and NOx emissions to evaluate their impact on visibility in nearby Class 1 areas. Two Class 1 areas have been identified as being close enough for potential impact by Louisiana sources: Breton National Wildlife Refuge (New Orleans area) and Caney Creek (Arkansas). When affected sources evaluate their impact through the air emissions dispersion modeling procedure and determine there is a significant visibility impact to a Class 1 area, the source must evaluate the potential necessity of installing emission controls equivalent to BART to reduce the visibility impact.

The BART provisions are part of the overall Regional Haze plan that focuses on reducing emissions from sources that, due to age, were exempted from other control requirements in the CAA. The BART rule requires an evaluation of the need for installation of BART on sources that fit specific criteria and can reasonably be expected to contribute to visibility impairment in Class 1 areas. A source is eligible for BART requirements if it falls into one of the 26 listed BART Source Categories, has the potential to emit 250 or more tons per year of any visibility-impairing pollutant, and began operations between August 7, 1962 and August 7, 1977.

A BART evaluation consists of:

- Listing of all available control options for the emitting sources;
- Elimination of technically infeasible options;
- Evaluation of technically feasible alternatives;
- Evaluation of compliance costs;
- Determination of compliance options' impacts to energy output;
- Determination of non-air quality environmental impacts for each compliance option;
- Consideration of emitting source's remaining useful life;
- Consideration of magnitude of visibility improvement from each compliance option; and
- Selection of the best alternative.

Previously, affected EGUs complying with CAIR SO2 and NOx regulations were considered by the EPA to be operating with controls equivalent to BART. This determination allowed sources potentially subject to the Regional Haze rule to avoid having to evaluate their impact on Class 1 areas. The implicit compliance for Louisiana sources changed when CSAPR replaced CAIR, as CSAPR only addresses seasonal NOx emissions in Louisiana. Without the previous CAIR regulation in place, which was equivalent to BART for both SO2 emissions and NOx emissions, the LDEQ may no longer claim compliance with BART requirements for SO2, which will require that emission sources be evaluated for visibility impacts on Class 1 areas.

Due to CSAPR's implementation, two Cleco Power EGUs became subject to further BART regulation after the regulatory authority determined the emissions have a significant impact on visibility in the nearby Class 1 areas. As a result, BART was determined for units at Brame (Nesbitt 1 and Rodemacher 2). For Nesbitt 1, which is natural gas fired, only BART for NOx was addressed and determined to be complying with CSAPR. For Rodemacher 2, which is fueled by low-sulfur subbituminous coal, BART was determined for NOx to also be compliant with CSAPR, while BART for SO2 was determined to be enhanced DSI. DSI (injection of trona) is currently applied at Rodemacher 2 to comply with MATS. Enhanced injection will involve operating the DSI system with an increased trona feed rate to lower the boiler SO2 emissions to the level required for visibility improvement at the Class 1 areas.

The LDEQ SIP for the first planning period was approved by EPA in December 2017. Compliance was initiated within one year after the effective date of the final rule.

The EPA's January 2017 amended version of the Regional Haze rule was to be applied to the second regional haze implementation period. The EPA explains in the January 2017 final rule that the Clean Air Act requires states to consider four statutory factors[18] in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class 1 area. The EPA clarified that states must determine what control measures are necessary to make reasonable progress by considering the four factors and use this information to determine the reasonable rate of progress for each mandatory Class 1 federal area.

In March 2020, LDEQ directed information collection request letters to operators of various emission sources, including one Cleco Power facility, Dolet Hills Power Station, that asked for information the whole of which would be a four-factor analyses of potential controls that if installed would lead to reasonable progress towards accomplishing visibility targets. In April 2020, Cleco Power responded to LDEQ that it had announced its intention to seek regulatory approval to retire the Dolet Hills Power Station at the end of 2021 and that Cleco Power anticipated that the facility would cease operations prior to the compliance deadline set forth in the Regional Haze Rule. Therefore, Cleco Power would not be providing the detailed information set forth in the information request.

On April 20, 2021, LDEQ published a notice that it plans to submit a proposed revision to the Louisiana SIP to the EPA for the second implementation period of the Regional Haze Program. LDEQ has not yet submitted a proposed SIP to the EPA.

Water Quality

The Clean Water Act contains provisions that require the EPA to evaluate all bodies of water subject to its jurisdiction for compliance with water quality standards and to establish a program

[18] The four factors are costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life.

to bring non-compliant bodies of water into compliance with applicable standards. In accordance with its National Pollutant Discharge Elimination System program, the EPA has tasked the LDEQ to issue Louisiana Pollution Discharge Elimination System ("LPDES") permits, which require water discharges from EGUs to meet the EPA's Steam Electric Effluent Guidelines. Owners of EGUs in Louisiana must submit an LPDES permit application to the LDEQ upon any changes to discharges at exiting EGUs or introductions of outfalls from new projects. The EPA implemented total maximum daily loading ("TMDL") standards for all impacted streams in Louisiana. The TMDL is the maximum amount of a given pollutant, from both point and nonpoint sources, that can be released into a body of water without causing the body of water to become impaired or violate state water quality standards. Under TMDL standards, the level of discharge of applicable pollutants will be set or modified in LPDES permits. Any new projects will be evaluated for potential TMDL standard impacts.

Revision of Effluent Limitation Guidelines

The Clean Water Act further requires the EPA to periodically review and, if appropriate, revise technology-based effluent limitations guidelines ("ELG") for certain categories of industrial facilities, including EGUs. The EPA revised the existing steam electric ELG and published a final rule in November 2015. The rule sets many different limits applicable to new or existing facilities. Among the most significant requirements are the following:

1. A "no discharge" requirement for fly ash transport water at existing facilities, with a limited exemption for fly ash transport water used as makeup water in a flue gas desulfurization scrubber;
2. A "no discharge" requirement for bottom ash transport water at existing facilities, with a limited exemption for use as makeup water in a flue gas desulfurization scrubber;
3. A "no discharge" requirement for flue gas mercury control wastewater; and
4. Stringent arsenic, mercury, selenium, and nitrate/nitrite limits based on physical/chemical and biological treatment for flue gas desulfurization wastewater.

The new limits do not apply until a date determined by the permitting authority that is no later than December 31, 2023. However, in November 2015, a petition for review was submitted to Court of Appeals for the Fifth Circuit. In April 2017, the EPA granted reconsideration of the ELG rule, per the request of industry parties. In August 2017, the United States Fifth Circuit Court of Appeals granted the government's motion to govern further proceedings which severed claims in the suit dealing with flue gas desulfurization wastewater and bottom ash transport water and held the issues in abeyance.

Following a rulemaking by the EPA in September 2017, the deadlines for application of the limits were changed to a date as soon as possible beginning November 1, 2020, and no later than December 31, 2023. On October 13, 2020, the EPA, in its 2020 ELG Reconsideration Rule, revised the requirements for two waste streams: flue gas desulfurization water and bottom ash transport water. The rule requires compliance with the bottom ash transfer water regulations as soon as possible, beginning October 13, 2021, and not later than December 31, 2025. The rule also allows for compliance by requesting the option to cease burning of coal, and therefore discharge of bottom ash transfer water, by December 31, 2028, through submitting a notice of planned participation ("NOPP") to the regulatory authority. A NOPP was submitted to LDEQ for both Dolet Hills Power Station and Brame before the October 2021 deadline.

In January 2021, Executive Order 13990 was issued, which required that agencies review actions from the previous presidential administration. Listed for review was the 2020 ELG Reconsideration rule. On March 29, 2023, the EPA published a proposed revised ELG rule, Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. Until the EPA finalizes a new regulation, the requirements for Cleco Power cannot be determined.

On April 12, 2019, the Fifth Circuit Court of Appeals responded to two aspects of the ELG rule that had been submitted in the November 2015 petition for review. The court determined that the discharge limit for combustion residual leachate was unacceptable, and it vacated that portion of the 2015 rule regulating leachate and remanded it back to the EPA for consideration consistent with its ruling. Because the EPA has not yet responded to the court in a final rulemaking, it cannot be determined what future regulatory requirements will be for treatment of leachate under the ELG rule.

Final Clean Water Act Section 316(b) Cooling Water Intake Structure Rule

Section 316(b) of the Clean Water Act ("316(b)") regulates adverse environmental impacts in the form of impingement and entrainment of aquatic species at water intake structures. These regulations establish requirements for cooling water intake structures and consider location, design, construction, and capacity. Utilities must consider 316(b) regulations when considering new projects and when renewing permits for existing EGUs.

The EPA issued a final rule regarding cooling water intake regulations on May 19, 2014. The rule intends to protect fish and other aquatic wildlife by minimizing capture both in screens attached to intake structures (impingement mortality) and in the intake structures themselves (entrainment mortality). The final rule requires facilities to:

- Adopt one of seven options for addressing impingement at the entrance of cooling water intake structures and gain approval by state or federal permit writers;
- Minimize entrainment, as directed by the permit writer, who takes several factors into account;
- Implement required measures as soon as practicable after the entrainment measures have been identified; the permit writer may set interim milestones for existing EGUs, and new EGUs must comply upon commencement of operations; and
- Provide extensive information in permit applications including physical and biological data on source water, intake structure and system data, proposed impingement compliance methods

and supporting study plans, previously conducted entrainment studies, and the operational status of subject EGUs.

EGUs that draw upon more than 125 million gallons of water per day must also provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts. The latter three studies must be peer-reviewed.

The seven options for addressing impingement at an intake structure, discussed above, include:

1. Qualifying closed-cycle cooling, either a cooling tower or pond, with daily monitoring.
2. 0.5 feet-per-second through-screen design velocity under all conditions.
3. 0.5 feet-per-second through-screen actual velocity under all conditions, with daily monitoring or equivalent calculations.
4. Existing velocity caps at least 800 feet offshore with barriers to exclude marine animals, with daily monitoring.
5. Modified traveling screens with flexible fish/shellfish protective measures including collection buckets, barriers to prevent fish loss, smooth woven mesh, low pressure wash or equivalent and gentle fish handling, all with optimization studies; the required studies are described as streamlined biological studies and monitoring with two years of monthly impingement data use for optimization of screen operation.
6. Technology systems including new velocity caps, management practices and operational measures that the permit writer determines will minimize impingement mortality of all non-fragile species as compared to Option 7 impingement mortality levels.
7. A one-year impingement mortality performance standard, including latent mortality, of no more than 24 percent of all life stages of non-fragile species collected in a sieve with a maximum opening of 0.56 inches and held 18-96 hours, with biological monitoring at least monthly; the permit writer may specify a different time period for the holding requirement.

Entrainment standards are set on a site-specific basis. The aim of the rule is to maximize entrainment reductions, as determined by the permit writer, based on the following factors:

- Numbers and types of organisms entrained;
- Impact on particulate emissions and other pollutants associated with entrainment technology;
- Land availability as it relates to measure feasibility;
- Remaining useful life of the EGU; and
- Quantitative and qualitative social benefits and costs, if sufficiently rigorous.

In addition, the permit writer may consider the following additional operational factors:

- Impacts on affected body of water;
- Thermal discharge impacts;
- Credit for flow reductions cause by EGU retirement;

- Impacts on electric system reliability in immediate area;
- Impacts on water consumption; and
- Availability of process, gray, waste, reclaimed, or reused water.

Compliance with the rule would be required as soon as practicable after the issuance of the next permit at each affected EGU. Existing EGUs subject to the proposed standards have 45 months following the rule's effective date to complete any required studies. For existing permits that expire more than 45 months after the final rule's effective date, permit applications must include the required study information discussed above. For permits that expire on the effective rule date, or within 45 months of passage of the final rule, permit writers can set a compliance schedule.

Since Dolet Hills Power Station was retired plant at the end of 2021, the rule requires the studies to be conducted for three Cleco Power plant locations: Acadia, Coughlin, and Teche. However, Cleco Power believes that closed cycle cooling systems in operation at Acadia will be sufficient for compliance. The installation of additional equipment would more likely be required at Coughlin and Teche. But, until required studies are completed at each EGU location, it is uncertain which technology option or retrofit would be required at each affected facility.

Section 316(a) of the Clean Water Act regulates effluent limitations for the control of the thermal component of any discharge to assure the protection and propagation of a balanced, indigenous population of fish, shellfish, and other wildlife in and on a body of water. Any new generation projects will be evaluated for effluent limitations, along with existing facilities as their permits are renewed.

Solid Waste Disposal

The Solid Waste Division of the LDEQ has adopted regulations and a permitting system for the management and disposal of solid waste generated by EGUs. These regulations require any new projects at affected EGUs to be evaluated for potential environmental impacts.

On April 17, 2015, the EPA published a final rule for regulating the disposal and management of CCRs, such as ash, from coal-fired EGUs. The final rule regulates CCRs like industrial or municipal solid waste. Key requirements can be found in Table 6.12, below.

Table 6.12: Subtitle D CCR Compliance Details

Effective Date:	October 14, 2015
Regulatory Status	Non-hazardous solid waste
Enforcement:	Enforcement through citizen suits; states can act as citizens

Corrective Action	Self-implementing
Financial Assurance	Considering subsequent rule using CERCLA 108(b) Authority
Permit Issuance	No permits required
Requirements for Storage (Containers, tanks, containment buildings)	No storage requirements
Existing Surface Impoundments	Demonstrate compliance with location restrictions and liner requirements or cease use and close the EGU within the prescribed time periods; groundwater monitoring required

The CCR rule contains management standards for existing impoundments and landfills. All management requirements were successfully addressed by the deadlines in the CCR rule. Some of the most important include location restrictions, design criteria (liner), structural integrity requirements, and ground water monitoring requirements with corrective action requirements. These are discussed below with compliance deadlines listed in Table 6.13, below.

Existing CCR surface impoundments are subject to the full suite of location restrictions relating to the placement of CCR in units above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, and in unstable areas. Conversely, existing CCR landfills are only subject to the location restrictions regarding flood plains (which are already in effect for all CCR units under existing Subtitle D rules). To comply with these location restrictions, owners/operators must obtain certification from a qualified professional engineer stating that units meet the specified conditions of the applicable location restriction. If the owner/operator of a unit subject to a location restriction is unable to make a compliance demonstration within the period referenced in the regulation, the owner/operator must, within six months, cease placing CCR and non-CCR waste streams in the unit and commence closure. However, a unit that cannot make a location restriction demonstration can continue operating for up to an additional five years if the owner/operator certifies that there is lack of alternative disposal capacity for the CCR both on-site and off-site of the facility. Complete demonstrations of compliance with the location restrictions were made by the deadlines in Table 6.13.

The rule also requires owners/operators of existing CCR surface impoundments to determine 2016, whether the impoundment qualifies as having a liner by October 17, 2016. If it does not, the impoundment is deemed an existing, unlined CCR surface impoundment and is subject to enhanced groundwater monitoring requirements (*i.e.*, the unlined impoundment must cease the receipt of CCR and commence closure or retrofit if it is determined during groundwater monitoring that releases from the unit exceed a groundwater protection standard). The documentation of the Cleco Power CCR impoundments as being lined was completed by the listed deadline found in Table 6.13, below, and posted in the required CCR website.[19]

Existing CCR surface impoundments must comply with several specified structural integrity requirements. This includes safety factor assessments that must be conducted at least every five years and be certified by a professional qualified engineer that they were conducted in accordance with the rule. The initial safety factor assessment was completed by the listed deadline found in Table 6.13, below, and posted in the required CCR website.[20]

All CCR landfills and CCR surface impoundments are subject to the rule's groundwater monitoring and, if necessary, corrective action requirements throughout the active life and post-closure care period of the CCR unit.

All ground water monitoring requirements including installation of the groundwater monitoring system, development of the groundwater sampling and analysis program, initiation of the detection monitoring program, and beginning the evaluation of the groundwater monitoring data for statistically significant increases over background levels, were initiated by the deadline found in Table 6.13, below, and posted in the required CCR website.[21]

Table 6.13: CCR Deadlines

Task/compliance demonstration	Deadline – Number of months following rule publication
Location restrictions	42
Liner	18
Structural integrity including hazard assessment, stability assessment and safety factor assessment	18
Groundwater monitoring and corrective action	30

The CCR rule could affect how electric utilities manage CCRs. For instance, if total closure of impoundments is implemented as a compliance mandate, EGUs that currently depend on sluicing of ash with water would have to modify EGUs to accommodate dry handling of ash.

[19] *See* www.cleco.com/about/regulatory/ccr-rule-compliance.
[20] *See* www.cleco.com/about/regulatory/ccr-rule-compliance.
[21] *See* www.cleco.com/about/regulatory/ccr-rule-compliance.

In May 2017, a petition for reconsideration of the rule was filed with the EPA. As a result of the EPA's reconsideration of the CCR rule, several new rules were planned to revise the rule with one being finalized in July 2018. Among other things, the rule extended the closure deadline for unlined impoundments that exceed the groundwater protection standard until October 2020.

Following the final publication of the CCR rule in August 2015, a petition for review of the rule, *USWAG v EPA*, was immediately filed in the U.S. Court of Appeals for the D.C. Circuit. The court issued an opinion in August 2018 that impoundments relying completely upon clay liners, not including a synthetic component, were not protective enough to be classified as adequately lined under the CCR rule. The court held that such impoundments should cease receiving CCR and close. Note that Cleco Power impoundment liners do not have synthetic components and therefore, according to the court opinion, would not be adequately protective.

In its response to the court's opinion, on August 28, 2020, the EPA published the regulation Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure. The rule implemented the holding in the D.C. Circuit's 2018 *USWAG v. EPA* decision that all unlined impoundments must close. However, the regulation also allows facilities to submit an alternative closure request to the EPA for the continued operation of an impoundment greater than forty acres in size, if the facility certifies that it will cease operation of the coal-fired boiler and complete closure of the impoundment by October 17, 2028, and demonstrates that the facility does not have alternative disposal capacity in the interim. Cleco Power submitted alternative closure requests to the EPA in the fourth quarter of 2020 for the continued operation of impoundments at Brame and Dolet Hills Power Station with ceasing of boiler operation and closure of impoundments taking place at each plant, respectively, on October 17, 2028 and October 17, 2023. Cleco Power ceased the placing of waste streams in the Dolet Hills Power Station bottom ash impoundments during third quarter 2022. In November 2022, Cleco Power notified the EPA that it was withdrawing its alternative closure request. Cleco Power is currently awaiting EPA approval of its request for Brame.

Hazardous Waste

The Hazardous Waste Division of the LDEQ regulates hazardous waste and issues identification numbers to sites where such wastes are generated. Cleco Power does not treat, provide long term storage for, or dispose of hazardous waste at any of its EGUs. Accordingly, no hazardous waste permits are required. Any hazardous waste produced by new generation projects will be properly managed and disposed of at federally permitted disposal sites.

Section 7: Resource Needs and Other IRP Assumptions

Reserve Margin and Unforced Capacity

According to MISO's Resource Adequacy Business Practice Manual,[22] the seasonal PRMR is the number of MWs zonal resource credits ("ZRC") required to meet a LSE's RA requirement. The RA requirements are established to ensure that LSEs have sufficient planning resources to reliably serve load for the applicable seasons. The PRMR is expressed per LSE and per LRZ.

Cleco Power's modeled projected capacity needs over the planning period using MISO's 2023/24 PY Planning Reserve Margins as follows:

- Summer (June, July, and August) = 7.4%
- Fall (September, October, and November) = 14.9%
- Winter (December, January, and February) = 25.5%
- Spring (March, April, and May) = 24.5%

MISO uses different effective load carrying capabilities ("ELCC") for renewable resources to calculate reserve requirements. The ELCC is the percentage of the installed capacity that can be used for reliability requirements. In Table 7.1, below, shows MISO's proposed wind and solar ELCC values. The wind ELCC for MISO is heavily weighted towards Zones 1 and 3 of MISO (Zones 1 and 3 consist of about 75% of all wind found in MISO), while MISO South has no wind. To adjust for this, Cleco Power used 9% for its summer ELCC, which is based on Zones 4-6 2022-2023 PY wind summer average credit values. The remaining wind ELCC seasonal values for Cleco Power modeling are scaled to summer values with respect to the MISO ELCC percentage values.

Cleco Power solar ELCC values for modeling purposes are 33% for summer, while the remaining seasons are scaled to MISO's seasonal ELCC values with respect to the summer ELCC value.

Table 7.1: ELCC values

	MISO ELCC %		Cleco Power Modeling ELCC %	
	Wind	Solar	Wind	Solar
Summer	18.1%	45.4%	9.0%	33.0%
Fall	23.1%	25.3%	11.5%	18.4%
Winter	40.3%	6.3%	20.0%	4.6%
Spring	23.0%	15.0%	11.4%	10.9%

[22] MISO's BPM -011r27

MISO Market Utilization

MISO utilizes its PRA to ensure LSEs have enough documented capacity to meet their load, plus reserve requirements on an annual basis. In simple terms, asset owners may offer their resources' ZRCs into the auction at a price determined by the asset owner. Beginning with the 2023/2024 PRA, each annual auction includes four seasonal pricing periods. An auction clearing price for each season is determined as the marginal cost where ZRCs are accumulated to meet the total MISO system peak plus reserves. All cleared ZRCs are paid the auction clearing price for that season, and each LSE must pay MISO the auction clearing price for its load for each season. Therefore, to the extent a utility has enough ZRCs to cover its peak demand plus reserves, no other financial cost is required. However, a utility that does not have enough ZRCs to cover its seasonal peak demand, plus reserves, will have a net balance remaining to pay MISO for its ZRC shortfall, multiplied by the auction clearing price.

The MISO PRA is intended to be used as a signal for long-term capacity planning resources. Unfortunately, the PRA never extends beyond a single year, with four seasons included in the auction. Because the PRA does not look further out than one year, there is no signal given to LSEs that a future system-wide capacity shortfall could be approaching, and the LSE will not receive a price signal with ample time to build longer-term capacity. For these reasons, Cleco Power will continue to utilize the PRA procedures annually as required by MISO, but will not rely on other utilities' potential short-term excess capacity in the PRA as a long-term solution to Cleco Power's capacity needs.

Environmental, Social, and Governance

Environmental, Social, and Governance planning and goal setting is playing a critical role in the utility industry due to the increasing awareness of the impacts of climate change and social responsibility. Investors and customers across the globe are demanding that companies focus efforts on decarbonizing the economy and increasing diversity within workforces and leadership related to ESG. A company's inability to manage ESG risks can have potential consequences such as the ability to access capital and maintain credit ratings. Cleco Power is incorporating sustainability into its operations by establishing specific ESG goals. As power plant retirements progress, it will be critical to incorporate cleaner solutions to meet the load requirements of Cleco Power's customers. ESG is incorporated into this IRP; however, Cleco Power will need to balance cleaner technologies with affordability and reliability. Cleco Power has a pathway to reduce GHG emissions by approximately 60% by 2030 using a 2011 baseline. Cleco Power retired one of its largest coal plants in 2021. Dolet Hills Power Station was retired five years earlier than anticipated. Cleco Power is preparing to add 240 MW of solar generation via the Dolet Hills Solar PPA (described below), should it be authorized by the LPSC in Docket No. U-36502. Cleco Power also is pursuing 49 MW of solar at England Airpark in Alexandria, Louisiana. Rodemacher 2, a PRB coal plant, will cease operations by 2028 due to EPA requirements to close or retrofit large surface impoundments that contain coal combustion residuals. Madison 3 was chosen as a leading candidate for a CCS system, which will reduce its CO2 emissions by approximately 95%, thereby reducing Cleco Power's overall carbon footprint. The looming energy transition must consider affordability, reliability, and resiliency for the electric grid. ESG priorities will need to be delivered through investment and innovation, and at the same time, Cleco Power must continue to deliver safe, reliable, and affordable power.

Project Diamond Vault

Madison 3, which is located near Boyce, Louisiana and is part of Brame, was recently chosen by Cleco Power as a leading candidate for a CCS system known as "Project Diamond Vault." Madison 3 has advantages that make it a strong candidate for CCS, including low sulfur emission rates, room for growth and new construction, strong geological formations that are suitable for permanent carbon sequestration, and a 3,000-acre cooling impoundment.

Project Diamond Vault is currently undergoing a $12 million Front End Engineering and Design ("FEED") study, which will serve as the basis for project contracting and construction. Of the $12 million, $9 million was provided from funds earmarked by the 2022 Omnibus Appropriations Bill. Details associated with design, costs, operations, and anticipated results will be conclusively available at the completion of the FEED study, which is expected to be completed in the second quarter of 2024. Cleco Power is committed to researching and engineering at the highest level and is committing resources to effectively evaluate a transformative project of this magnitude.

Cleco Power expects the enhanced tax credits under section 45Q of the Internal Revenue Code, recently enacted as a part of the Inflation Reduction Act of 2022 ("IRA"), will enable financing to fund the initial investment into the project and operations.

For modelling and planning purposes in this Final IRP Report, Cleco Power will assume a 200 MW reduction of Madison 3 generating capacity beginning in 2028 and continuing throughout the study period. It should be noted that Project Diamond Vault is still undergoing a FEED study to understand the feasibility of the project and has not been approved by the LPSC. Should Cleco Power decide to proceed with Project Diamond Vault, it would be reviewed by the LPSC in a separate docket.

Dolet Hills Solar PPA

Cleco Power and Dolet Hills Solar, LLC, a project company subsidiary of D.E. Shaw Renewable Investments, LLC, have entered into a power purchase agreement for a 240 MW_{ac} solar facility to be built near the recently retired Dolet Hills lignite-fired power plant in DeSoto Parish, Louisiana. For modeling purposes, Cleco Power assumes that it will receive energy beginning on January 1, 2025 and continuing through the end of the study period (2042). The Dolet Hills Solar PPA is currently pending LPSC authorization and has not been certified at the time of this Final IRP Report.

England Airpark Solar

England Airpark Solar is the planned installation of a 49 MW solar farm which will be built at the England Airpark in Alexandria, Louisiana, and is expected to provide renewable power beginning in early 2027. Due to the recent development and size of this project, it was neither modeled in Aurora, nor was it included in any analyses performed in this IRP.

Resource Alternatives

Supply Side Resources

Cleco Power consulted with Energy Exemplar to identify viable supply-side resource alternatives. Energy Exemplar releases an Excel spreadsheet that models the most current capital cost annually, based on EIA published Annual Energy Outlook 2022 ("AEO 2022"), and inclusive of adjustments for regional and forward costs for technologies. The technology assumptions for CTs and CCGTs are described in Tables 7.2a and 7.2b, below. Solid fuel options were not considered in this Final IRP Report.

As a stakeholder, Wärtsilä asked Cleco Power to use Wärtsilä's web portal to gain access to confidential pricing information. The Wärtsilä data provided is based on this proprietary, market sensitive information.

[redacted]

	Cumbustion Turbine		
2020 $'s	Aeroderivative	Industrial Frame	[redacted]
Total Overnight Cost ($/kW)	$1,262	$766	
Size (MW)	105	237	
FOM ($/kW - year)	$17.06	$7.15	
VOM ($/MWh)	$4.80	$4.60	
Heat Rate	9,124	9,905	
NOx (lbs/mmBtu)	0.03	0.05	
SO2 (lbs/mmBtu)	0	0	
CO2 (lbs/mmBtu)	120	120	
Depreciable Life	30	30	

Table 7.2b: New Combined Cycle Turbine Technologies

2020 $'s	Combined Cycle Gas Turbine Single-Shaft (1x1)	Combined Cycle Gas Turbine Multi-Shaft (2x1)
Total Overnight Cost ($/kW)	$1,172	$1,036
Size (MW)	418	1083
FOM ($/kW - year)	$14.76	$12.77
VOM ($/MWh)	$2.60	$1.91
Heat Rate	6,431	6,370
NOx (lbs/mmBtu)	0.007	0.007
SO_2 (lbs/mmBtu)	0	0
CO_2 (lbs/mmBtu)	120	120
Depreciable Life	30	30

Renewable resources modeled are shown below in Tables 7.3a and 7.3b, below. Table 7.3a illustrates overnight capital costs before any IRA tax incentives are considered, but does show the production credit used ("PTC") for modeling. Cleco Power used a production tax credit of $26.00/MWh (in 2022 dollars). All renewable data is based on EIA's AEO 2022 data except for offshore wind, which is based on NREL data.

Table 7.3a: New Renewable Technologies with Production Tax Credit

	Renewables with Production Tax Credit					PPA
2020 $'s	Battery storage	Wind	Offshore Wind	Solar photovoltaic (PV) with tracking	Solar PV with storage	Solar*
Total Overnight Cost ($/kW)	$1,284	$1,676	$3,232	$1,295	$1,705	
Size (MW)	50	200	400	150	150	100
FOM ($/kW - year)	$25.33	$26.90	$112.35	$15.58	$32.85	
VOM ($/MWh)						$42.00
Production Tax Credit ($/MWh)	$24.75	$24.75	$24.75	$24.75	$24.75	
Depreciable Life	15	20	20	25	15	25
Capacity Factor	16%	35%	35%	24%	21.6%	24%

Table 7.3b illustrates the same technologies modeled with the investment tax credit ("ITC") applied to the total overnight costs. For modelling purposes, the ITC was a direct reduction to capital costs.

Table 7.3b: New Renewable Technologies with Investment Tax Credit

2020 $'s	Renewables with Investment Tax Credit					PPA
	Battery storage	Wind	Offshore Wind	Solar photovoltaic (PV) with tracking	Solar PV with storage	Solar*
Total Overnight Cost ($/kW)	$937	$1,224	$2,359	$945	$1,245	
Size (MW)	50	200	400	150	150	100
FOM ($/kW - year)	$25.33	$26.90	$112.35	$15.58	$32.85	
VOM ($/MWh)						$42.00
Depreciable Life	15	20	20	25	15	25
Capacity Factor	16%	35%	35%	24%	21.6%	24%

*The solar PPA starts at $42/MWh and escalates at 2.5% annually.

Demand Side Resources

Cleco Power contracted with DNV Energy Insights USA Inc. ("DNV") to study the market potential for both EE and DR resources in Cleco Power's service territory. DNV's market potential studies will determine the baseline from which EE and DR program savings goals can be established. For this report, EE indicates a set of actions, activities, or measures that impact energy use, energy use patterns, or customer behavior as they relate to energy consumption. Examples of EE programs modeled include, but are not limited to, residential appliance replacement, efficient interior lighting, residential home weatherization, commercial and industrial HVAC tuning, and lighting replacement. DR programs are almost entirely made up of direct load control programs for residential and commercial air conditioning and heating as well as TOU rate tariffs for all customer classes to incentivize customer load shifting away from peak hours. DR programs typically result in lower peak demand requirements but negligible energy reductions.

The key objectives of the market potential studies were to:

- Identify areas that have the potential for efficiencies;
- Determine the potential for EE and DR in Cleco Power's service territory over a 20-year period; and
- Estimate costs of implementing achievable and cost-effective measures.

DNV conducted a "bottom-up" analysis across residential, commercial, and industrial sectors for both the EE and DR studies to achieve these objectives. DNV considered sector-specific factors including program costs, customer makeup, rate structures, and building types. DNV provided Cleco Power with hourly load shapes and annual program costs for EE, and annual demand reductions and program costs for DR. These load shapes and costs were independently input into the Aurora model as discrete resource options in the same manner as supply-side alternatives. If picked, EE and DR would start in 2024 and continue its program until the end of the study period (2042).

Table 7.4 shows the max capacity savings for Cleco Power, annual cumulative project costs, and the costs (2020 $/MW/week) that was used as an input into Aurora. EE is a much cheaper alternative because there is a reduced need for power in all hours, unlike Demand Response which only has a reduction of power in a few peak summer hours throughout the year.

Table 7.4: Demand Response and Energy Efficiency

Demand Response	2024	2025	2026	2027	2028	2029
Capacity (MW)	15.4	18.7	23.8	30.1	37.9	47.0
Costs (2020 $/MW/wk)	$ 729,959	$ 264,135	$ 254,823	$ 238,994	$ 228,080	$ 218,567
Cumulative project costs (2020 $)	$ 4,149,219	$ 5,970,354	$ 8,212,910	$ 10,871,147	$ 14,057,565	$ 17,850,827

Energy Efficiency	2024	2025	2026	2027	2028	2029
Capacity (MW)	15.9	34.9	55.6	75.1	93.8	111.5
Costs (2020 $/MW/wk)	$ 31,118	$ 16,732	$ 10,743	$ 7,229	$ 5,299	$ 4,091
Cumulative project costs (2020 $)	$ 9,435,265	$ 20,119,126	$ 30,796,557	$ 40,300,158	$ 48,808,036	$ 56,471,144

Detailed reports on the EE and DR options for this Final IRP Report are contained in the market potential study provided as Appendix 3: Cleco Power DSM Potential Study Report.

Pre-Screening New Resources

Section 6(e) of the IRP Order provides that, if there are numerous supply-side resource alternatives, screening tests may be performed to reduce the number of analytical permutations that need to be performed by the model. To perform the pre-screening of potential resources, Cleco Power analyzed the LCOE. The LCOE includes the revenue requirement of the capital investment, on-going fixed O&M, and heat rate variances, over different capacity factors. Due to the similar characteristics of the various resource options among the CCGT class and the CT class, Cleco Power screened all such resources on an LCOE basis. The specific assumption for delivered gas costs for gas fired units is $3.5/MMBtu in Figures 7.1-7.2. The LCOE values were calculated at various operating capacity factors to determine if certain options were more expensive than similar options. In addition, the LCOE shown in Figures 7.1-7.2 are responsive to specific requests from stakeholders for the inclusion of LCOE calculations, and demonstrate Cleco Power's commitment to a collaborative IRP process. Table 7.5 contains the LCOE values for renewable resources, demand response, and energy efficiency.

As shown in Figure 7.1, below, there were only two options for a combined cycle gas turbine: a single-shaft and a multi-shaft. The generic choices of CCGT help reduce runtime of the Aurora production model by eliminating the iterations needed to optimize the portfolios in each case. If there is to be a future need for a combined cycle, Cleco Power will issue an RFP for a more specific combined cycle technology which will require a deeper, more in-depth analysis.

Figure 7.1: CCGT LCOE $/MWh (2022 $)

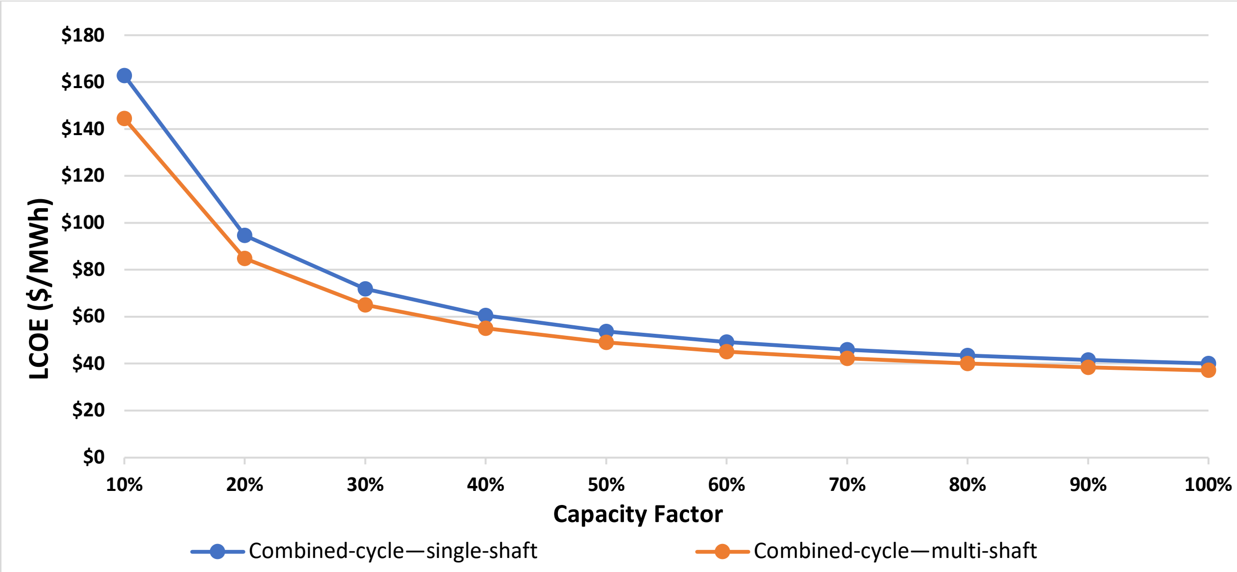


Figure 7.2 illustrates a similar comparison among CT options. Cleco Power opted not to include the Internal Combustion Engine technology due to the similarities to the Wärtsilä technologies.

Figure 7.2: CT LCOE $/MWh (2022 $)

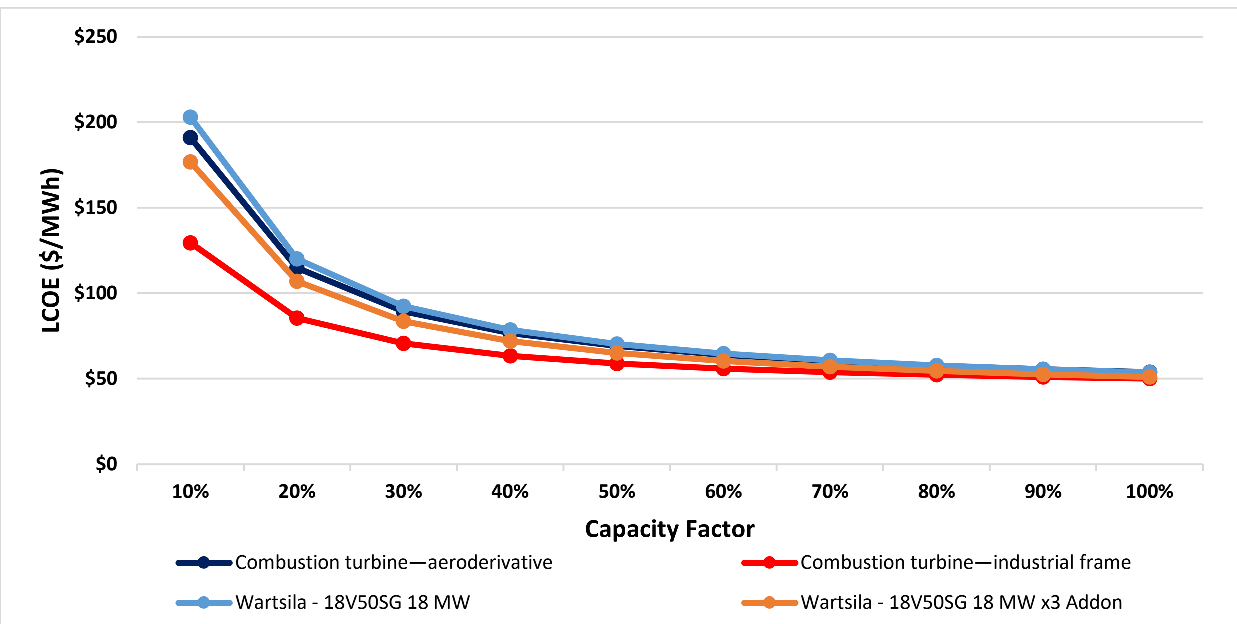


Table 7.5 illustrates the LCOE for potential renewable energy sources. These costs are inclusive of 30% ITC estimates, a $26/MWh (2022 $) PTC, and a base line value with no incentive. At the Commission's September 21, 2022 Business and Executive Session, Commissioner Greene issued a directive for each electric utility to provide an evidentiary record of all costs and benefits

associated with power generation and resource supply from offshore wind for Louisiana utilities, including the utilities' data assumptions and any customer impacts of offshore wind being utilized now or in the future for the utility resource portfolio. In the renewable category, offshore wind input data was collected using NREL's Annual Technology Baseline ("ATB") 2022 and was modeled with both an ITC and PTC. The costs provided by the ATB are not inclusive of transmission upgrades (dependent on the size of a project as well as how far from shore the project is located), insurance premiums, or of any environmental studies related to offshore wind in the Gulf of Mexico. However, given Commissioner Greene's directive, above, Cleco Power will continue to analyze possible incorporation of offshore wind resources into its resource portfolio as more information and detail becomes available.

Table 7.5: Renewable LCOE $/MWh (2022 $)

2022 $/MWh	Base	PTC	ITC
Solar	$49.64	$34.18	$40.64
Wind	$53.01	$35.93	$42.97
Battery	$72.86	$52.92	$59.50
Offshore Wind	$109.62	$94.16	$102.88
Demand Response (DR)	$1,473.04		
Energy Efficiency (EE)	$44.03		

Capacity Limits for Potential Resources

Cleco Power resource limits were set for technology options annually and cumulatively for the studies. Performing studies with no capacity limits caused the run-time for each scenario to increase, but did not materially change results of either the studies or the Action Plan. Table 7.6, below, shows the limits used for each potential technology. The Annual Max column is the number of units Aurora was allowed to build for Cleco Power in one year. Annual maxes were constrained by reasonable capitalization and execution assumptions. The Overall Max column is how many of each technology the model was allowed to build for Cleco Power throughout the entire study.

Table 7.6: Capacity Limits

CLECO	Annual Max	Overall Max
CCCT gas_oil Adv 1x1_06	2	40
CCCT gas_oil Adv_06	1	20
SCCT Conv - Aero_06	9	180
SCCT Adv_06	6	120
Battery Storage_06	18	360
Wind_06	3	60
Solar PV_06	6	120
Solar PV_Sto_06	5	100
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
Solar PPA 100	6	120
Demand Response	1	1
Energy Efficiency	1	1

Sensitivity Analyses

Cleco Power conducted sensitivity analyses on its reference case by adjusting major input variables. All sensitivities were analyzed independently using the Aurora market model. Sensitivity cases include:

- Constrained (high) natural gas prices;
- Low natural gas prices;
- Upside Electrification; and
- CO2 emission pricing included in unit dispatch decisions and energy cost.

Commodity Sensitivities

As mentioned in Section 4, a constrained supply and low natural gas sensitivities were developed by FEP using proprietary natural gas production forecasting. Annual values associated with the natural gas curves can be found in Appendix 2: Commodity Price Projections.

With respect to PRB coal, approximately 75-80% of the delivered cost of PRB coal is dependent on rail transportation costs, and not the underlying coal commodity. Therefore, assumptions surrounding fluctuations in the price of the coal commodity have a minimal impact on the delivered cost to Cleco Power's customers. Price fluctuations are more likely to occur due to changes in contractual pricing regarding rail transportation. Due to Rodemacher 2's 2028 expected cessation of coal-fired operations, a high PRB coal case is not considered.

Madison 3 burns a combination of petcoke and Illinois coal. Weighted average pricing at Madison 3 is subject to petcoke price fluctuations, as well as changes in the blend percentage between petcoke and Illinois coal. The price used is based on current delivered costs with a 2% annual increase due to inflation.

Cleco Power chose to not run any cost sensitivities on solid fuel.

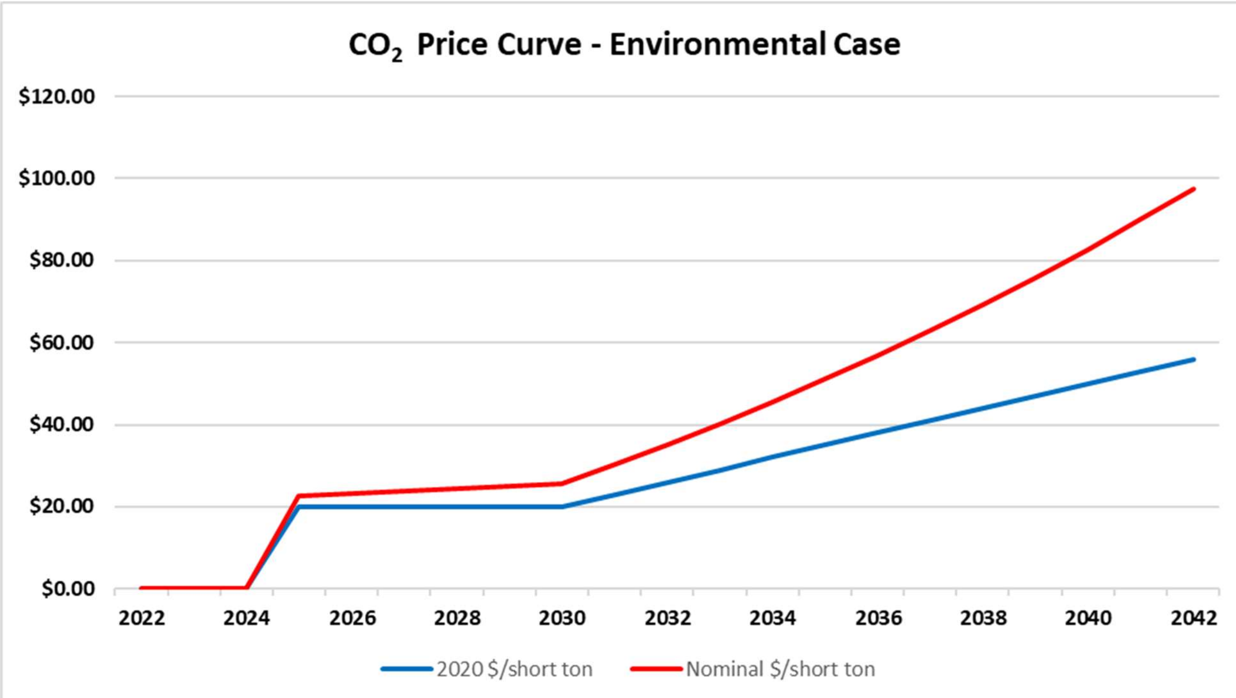
Load Sensitivities

As mentioned in Section 2, Cleco Power's Final IRP Report studied three different load scenarios: Reference Case, Base Electrification, and Upside Electrification. The electrification cases are dependent on adoption of electric vehicles and gas compression. The Base Electrification case is a more conservative approach, while the Upside Electrification case assumes a more aggressive adoption. After receiving comments from the LPSC Staff, the Base Electrification sensitivity was eliminated due to marginally different results between the Reference Case and Upside Electrification Case.

Environmental Sensitivities

CO2 emission costs have the potential to be a critical component in future resource planning. No environmental rule is currently in place nationally or in Louisiana that requires purchasing allowances or paying an effective "carbon tax," and there is no such legislation set to become active soon. However, Cleco Power recognizes the possibility that such costs may exist at some point in the future. To account for this possibility, Cleco Power simulated a CO2 cost sensitivity that applies a $/ton cost to every ton of CO2 emitted in the model. The cost of CO2 was included as an input to the model and thus was allowed to influence the dispatch of each generator. The CO2 price curve was supplied to Cleco Power by Filsinger Energy Partners. Please see Figure 7.3, below.

Figure 7.3: CO2 Cost Projection



<u>IRP Scenarios and Sensitivities</u>

Cleco Power evaluated three general scenarios: Reference, Upside Electrification, and Environmental Considerations. The scenarios are constructed as combinations of the sensitivities described above. The scenarios are then sensitized with natural gas prices at the supply-constrained (high) and low gas price levels. The major assumptions for each scenario are listed in Table 7.7, below:

Table 7.7: IRP Scenarios

		Reference Case	Upside Electrification	Environmental
Natural Gas Curve		Base	Base	Base
		Constrained	Constrained	Constrained
		Low	Low	
Cleco Power Load Curve		Base	Upside Electrification	Base
				Upside Electrification
CO2 Emission Cost		No	No	Yes
Planning Reserve Margin	Summer	7.4%	7.4%	7.4%
	Fall	14.9%	14.9%	14.9%
	Winter	25.5%	25.5%	25.5%
	Spring	24.5%	24.5%	24.5%

Cleco Power recognizes that among all major variables included in the IRP analysis, a multitude of combinations could be used to create many potential scenarios to analyze. The selected scenarios and sensitivities were chosen to provide an analytical perspective related to possible market futures and planning insight.

<u>Financial Assumptions</u>

Financial assumptions used in the development of the Final IRP Report are listed in Table 7.8, below.

Table 7.8: Financial Assumptions

Assumption	Value
Inflation Rate	2.5%
Wtd. Avg. Cost of Capital	6.7%
Discount Rate	6.7%
Income Tax Rate	26.93%

Weighted average cost of capital ("WACC") is calculated as:

$$\underline{\boldsymbol{WACC = (equity\ ratio * return\ on\ equity) + (debt\ ratio * after\ tax\ cost\ of\ debt)}}$$

where,

equity ratio = 52%;

return on equity = 9.5%;
debt ratio = 48%; and
after tax cost of debt = 1.76%.

Qualified Facility Considerations

Qualifying facilities located within the Cleco Power LBA have provided an annual average of approximately 13,000 MWh over the past 4 years (2019 – 2022). Energy generated by QFs is delivered to MISO. The MWhs serve as a reduction to Cleco Power's load in MISO, thereby reducing costs by MISO's locational marginal pricing ("LMP") rates. Because QF generation within Cleco Power's LBA delivers a negligible amount of energy to the MISO system, and the cost associated with QF energy is paid at avoided cost, QFs were not specifically modeled in this IRP. Cleco Power does not expect to experience a material increase in QF output, cogeneration, or merchant activity in the foreseeable future.

Section 8: Results

Optimized Portfolio[23]

Cleco Power is currently in a position to transform its existing generation portfolio. This transformation is:

- enabled by key legislation;
- catalyzed by environmental goals;
- required by capital markets; and
- supported by customers.

Equally, this transformation is challenged with the:

- responsibility of balancing customer affordability, reliability of the system and resource adequacy;
- availability of technologies; and
- variability of market planning dynamics.

Cleco Power's current generation fleet is a diversified fleet made up of primarily natural gas, coal, and petcoke generation assets. The following Optimized Portfolio accounts for the items detailed above, plus the procurement of resources and the diversified mix of those resources—all of which will be highly dependent on dynamic variables that will require final resolution.

[23] The Optimized Portfolio is assembled on selections by the Aurora model using load and cost assumptions described in this Final IRP Report, which will be used in determining Cleco Power's Action Plan. Therefore, the Optimized Portfolio is used as a guide in determining potential RFP parameters and does not represent a definitive solution that Cleco Power will pursue.

OPTIMIZED PORTFOLIO ELEMENTS

- **Retirement** of Teche 3 at the expiration of the DEMCO Power Supply and Service Agreement (March 31, 2024).
- **Retirement** of Nesbitt 1 by 2028.[24]
- **Retirement** of Rodemacher 2 by 2028.[25]
- **Maintain operation** of Madison 3 as CCS at the facility is being evaluated for prudency.
- **Maintain operation** of Coughlin 6 and 7 through the end 2042.
- **Maintain operation** of Acadia through the 2042.
- **Include additional** energy efficiency initiatives and benefits.
- **Include 240 MW** of Dolet Hills Solar PPA.

- **Additions that enable fuel diversity, ESG, reliability and affordability:**

  Pre-2030

  - 250 MW (ICAP) of owned solar capacity and energy: 2026
  - 250 MW (ICAP) of owned solar capacity and energy: 2027
  - 150 MW of installed battery storage: 2027
  - 400 MW of installed 1x1 CCGT: 2028

  Post-2030

  - 500 MW (ICAP) of owned solar capacity and energy: 2031
  - 150 MW (ICAP) of installed battery storage: 2031
  - 100 MW (ICAP) of installed battery storage: 2034

Modeling

The Aurora software algorithm identifies options for least-cost system results, while maintaining capacity and energy constraints throughout time. Acknowledging that inputs and least-cost driven outcomes to these future scenarios are different, it is also evident that important prevailing themes have emerged. These themes should remain in focus when developing an optimized, dynamic solution that can be strategically adjusted as future scenarios materialize. The Optimized Portfolio considers all key awareness factors identified in the Optimization of the Modeling Results section below, including:

- reliable and affordable electricity for customers;
- environmental goals and access to affordable capital;
- emerging customer demands;
- sustainability of Cleco Power investment; and

[24] The retirement of Nesbitt 1 is dependent on future environmental rules and aging infrastructure costs.
[25] The retirement of Rodemacher 2 is dependent on a joint owner agreement and is due to the EPA's CCR rule.

- economic development within the state of Louisiana.

This Optimized Portfolio has been used for cross-testing, demonstrating performance and outcomes in different scenarios and sensitivities. The outcomes have been economically measured against alternate optimized portfolios within the Aurora scope of constraints and targets. Actual resource mix and amount (MWs) acquired will be determined by binding bids submitted through a formal RFP process conducted pursuant to the MBM Order. Cleco Power may also adjust its Action Plan based on risks to the Optimized Portfolio, including changes in load, load growth, the cost of new technologies, tax incentives, environmental compliance, transmission availability, and other market factors that may arise that are currently undetermined. The following portfolios have been identified for cross-testing and performance evaluation:

1) Reference Portfolio – The Aurora model's chosen least-cost portfolio in the base load, base gas, no carbon emissions cost scenario.
2) Upside Portfolio – The Aurora model's chosen least-cost portfolio in the upside electrification load, base gas, no carbon emissions cost scenario.
3) Optimized Portfolio – Cleco Power's preferred portfolio, optimizing Aurora's least-cost portfolio utilizing results and consideration of other factors mentioned in Appendix 11.

Each of these portfolios were cross-tested against various commodities, load growth, capacity market outcomes, and carbon emissions costs. The results are expressed in incremental LCOE to serve load displayed in $/MWh units. These are not bill impacts relative to any particular customers or customer classes. The basis used as a reference point and subsequent incremental LCOE impact assume:

- No addition of or removal of EGUs made by the Aurora optimization tool; and
- Base Load, Base Gas market.

The LCOE Table 8.2, below, demonstrates the levelized cost cross-testing results for the three portfolios evaluated.

Table 8.1: Sensitivity Keys

Load Sensitivities Key
Reference = L1
Upside Electrification = L2
Gas Commodity Key
Low Gas = G1
Base Gas = G2
Constrained Gas = G3

Table 8.2: Incremental LCOE

Load Sensitivity	Gas Commodity	CO2 Cost	Incremental LCOE ($/MWh) Reference Portfolio	Upside Portfolio	Optimized Portfolio
L1	G1	No	(1.26)	0.92	1.97
L1	G2	No	3.00	4.85	4.72
L1	G3	No	13.79	15.37	13.55
L2	G1	No	7.92	8.78	9.99
L2	G2	No	12.40	13.32	13.71
L2	G3	No	25.34	25.65	24.40
L2	G3	Yes	38.50	39.28	35.71
		Average	**14.24**	15.45	14.86
		Standard Dev.	13.67	13.19	**11.70**

The LCOE Table 8.3, below, demonstrates the carbon emissions intensity reduction in 2030 from the 2011 baseline results for the three portfolios evaluated.

Table 8.3: Carbon Intensity Factor Reduction (tCO_2/MWh)

Load Sensitivity	Gas Commodity	CO2 Cost	Carbon Intensity 2030 vs. 2011 Baseline Reference Portfolio	Upside Portfolio	Optimized Portfolio
L1	G1	No	-64%	-64%	-70%
L1	G2	No	-65%	-64%	-70%
L1	G3	No	-66%	-66%	-71%
L2	G1	No	-62%	-63%	-68%
L2	G2	No	-63%	-64%	-68%
L2	G3	No	-65%	-65%	-70%
L2	G3	Yes	-64%	-65%	-69%
		Average	-64%	-65%	**-69%**
		Max Potential	-66%	-66%	**-71%**

The Optimized Portfolio outperforms the other portfolios in high gas price futures and futures with carbon emission costing standards, which have the highest market energy pricing results. The Optimized Portfolio acts a functional and diversified hedge to market energy pricing increases not in the Company's control, protecting customers from unfavorable market conditions and costs. The Optimized Portfolio also outperforms the other portfolios in measurements of carbon emission intensity, supporting the Company and its customers' environmental goals.

The Optimized Portfolio is also in the best position to support economic development activity and the positive impacts resulting from attracting new industrial load to the state of Louisiana and Cleco Power's service territory. Accelerated additions of renewable EGUs to the Cleco Power portfolio relative to the other portfolios enables and supports the time-sensitive attraction and execution of contracts with new loads emerging in the state. The LCOE results in Table 8.2 do not contain the impacts of acquiring new industrial load, outside of the load curves provided as assumptions in this Final IRP Report. However, acquisition of an additional 100 MW – 200 MW could add an additional $0.50/MWh - $1.50/MWh of incremental LCOE reduction to the results in Table 8.2.

The Optimized Portfolio is capable of meeting Cleco Power's currently projected capacity and energy requirements through 2042 while providing diversity of the portfolio; mitigation for the inherent price volatility of fuel markets; and focus on the fundamental need for generation resources that can be dispatched in all hours of need. The Optimized Portfolio also provides Cleco Power with flexibility to respond to changes in circumstance, including the uncertainties of environmental regulations and/or other regulatory rulemakings.

There are inherent risks in the Optimized Portfolio. These risks include but are not limited to:

- **Changes in load or load growth**
  Cleco Power may gain or lose retail or wholesale customers, which could materially influence the quantity of resources that Cleco Power needs to procure.

- **Changes to planned operations of existing resources**
  Changes in performance of any Cleco Power resource may result in decisions to derate or retire additional units, which would materially influence the quantity of resources procured in an RFP. Additionally, the changes to the MISO capacity auction accreditation as well as the outcome of the LPSC Minimum Capacity Obligation docket could materially impact the incentives and risks associated with Cleco Power's costs associated with continued maintenance of EGUs.

- **Economics of actual available resource alternatives, including cost of new technologies, availability of tax credits, and changes in market conditions**
  The pricing included in the new resource alternatives is indicative of market pricing from 2022 EIA and NREL data, which Cleco Power believes to be behind the current renewable market. Consequently, changing market conditions could alter the price of different products that will be bidding into an RFP and could result in a substantially different mix of new resources.

- **Energy price risk associated with large volumes of energy relative to small amounts of granted capacity**
  While some intermittent resources receive only a fractional portion of ICAP as seasonal capacity accreditation in MISO, those same resources may serve as affordable and competitive solutions and produce significant amounts of energy during times of constraint. If MISO market participants procured large volumes of intermittent resources (*e.g.*, wind and solar) in the near term as a strategy to meet the MISO capacity requirements, a very large amount of energy would be added to the MISO market, but

with availability only at specific times. The result could potentially lower market prices at certain levels of penetration. The cannibalization of value could change the initial value proposition analyzed as market participants chose these intermittent resources as affordable energy solutions.

- **Creditworthiness of potential new resource counterparties**
  Cleco Power must account for the creditworthiness of potential counterparties when evaluating potential bids in an RFP. This could impact the volumes of renewable capacity and energy that are eligible for participation.

- **Environmental compliance**
  New environmental rules may change both the targeted volume of renewable capacity, as well as impact future generation retirements.

- **Transmission availability and cost**
  Cleco Power may receive bids in an RFP from resources outside of the MISO transmission footprint. Without knowing the source of a potential renewable project, it is difficult to speculate on the availability of adequate transmission capacity or the potential cost of required transmission upgrades for delivery to Cleco Power. Significant transmission costs or lack of availability could significantly impact the economics of bids, resulting in a different mix of new resources than the Optimized Portfolio.

- **MISO queue**
  Proposed generation facilities must enter the MISO interconnection queue. Currently, the entire interconnection process requires approximately 500 days to complete. However, MISO does provide a replacement generation process that can mitigate the time restrictions (in short, by utilizing an existing interconnection).

Action Plan

Per the IRP Order, the Action Plan "details the specific actions that [Cleco Power] expects to perform to implement the IRP during the first five years of the planning horizon. The Action Plan serves to guide the utility's planning and decision-making process following the completion of the IRP."[26]

Consistent with current practices, Cleco Power will continue to monitor market trends, electricity usage trends, the safety and reliability of its generation fleet, regulations, ESG, and other relevant factors to identify any warranted resource adjustments.

[26] *See* LPSC Order No. R-30021.

Existing Supply-Side Resources

- Cleco Power will continue to maintain and operate: Madison 3
  - The operation of Madison 3 and prudency of Project Diamond Vault will continue to be explored as the FEED study is finalized. Prudency will fully consider customer impact, risks, and the continued pathway towards clean, reliable solutions that support Cleco Power customer needs.
- St. Mary Clean Energy Center
- Acadia Power Station
- Coughlin Power Station
- Teche 4
  - To be maintained as a black-start generation asset.

Teche 3 will continue to be maintained and operated as a capacity resource until an assessment of MISO's seasonal PRA construct is complete and the expiration of Power Supply and Service Agreement between Cleco Power and DEMCO on March 31, 2024. Once the necessary assessments are completed, Cleco Power will work through all appropriate procedures to safely and reliably retire Teche 3.

Nesbitt 1 will continue to be maintained and operated as a capacity resource until an informative evaluation of the EPA's Cross-State Air Pollution Rule and MISO's seasonal PRA construct is complete. Once the necessary assessments are completed, Cleco Power will work through all appropriate processes to evaluate the load needs of Cleco Power and any potential economic and reliable options to replace the technologically aged generation resource. Near-term RFPs will evaluate replacement generation options for Nesbitt 1.

Demand-Side Resources

Cleco Power opted to participate in the LPSC's Quick Start Energy Efficiency program, which ultimately led to the current EE program that began offering EE measures to residential and non-residential customers on November 1, 2014. Cleco Power intends to maintain its EE program through the current cycle, and work with the LPSC to consider expansion programs as discussed in Section 3, and participate in additional rulemaking that the LPSC may introduce. Cleco Power will also continue with its TOUCH program to evaluate expansion of TOU tariffs for peak demand reduction. Cleco Power also notes that various regulatory incentives may be appropriate to balance and achieve various goals.

New Resources

Renewable Resource and Battery RFP Issuance 1

Cleco Power intends to issue an RFP for up to 500 MW of installed renewable capacity prior to January 1, 2024, consistent with the current MBM Order. The RFP will also solicit and consider up to 150 MW of battery storage options (both standalone and as project add-ons) to complement the renewable resource additions. The installed MW target for battery storage will be approximately 0.3 MW battery for every 1 MW renewable. This RFP may be exclusive to projects that demonstrate the ability to meet a target commercial operation date prior to January 1, 2027. The renewable RFP is anticipated to include solar development within MISO South, wind options (likely sourced within either MISO or SPP) with firm transmission delivered into MISO South, and other renewable alternatives. Potential resources will include all criteria and necessary qualifications defined as a part of the request process.

Renewable Resource and Battery RFP Issuance 2

Pending results of the first RFP issuance and future customer load, an additional issuance is expected. The specific requested resources and timing of this issuance will remain dynamic, pending determination of additional Cleco Power resource needs.

The RFP(s) will be designed to solicit a variety of competitive bids and include utilizing the MISO generation replacement process to increase value and reduce risk for Cleco Power's customers. Cleco Power will evaluate asset ownership options and optimal levels of both ownership and PPA structures to mitigate risks related to:

- prevailing market prices post-PPA term sunset;
- interconnection costs and MISO requirement uncertainty;
- counterparty credit;
- operational control and optimization;
- asset condition, maintenance, and performance;
- contribution to environmental targets; and
- credit risks.

To reduce risk and capture value for customers, Cleco Power will objectively determine an optimal mix of ownership of the asset(s), through a Commission-authorized process.

Issuing an RFP and acquiring renewable generation resources is a vital step to addressing many goals:

1) Essential for reduction of greenhouse gas emissions, and driving down customer prices.
    - Many of Cleco Power's current, as well as potential, industrial customers have ESG goals that need to be met by reducing their greenhouse gas emissions to execute sustainable future business objectives.
    - Cleco Power has (Scope 1) carbon emissions reduction goals of 60% by 2030.
2) Renewable resources also play an important role in further diversifying the Cleco Power's generation portfolio to hedge potential high market locational marginal prices, which is a direct impact to customer affordability.
3) Finally, Cleco Power will need to have renewable resource projects in development before implementing a green tariff (although a green tariff may be implemented should the Commission authorize the Dolet Hills Solar PPA).

Dispatchable Resource RFP Issuance

An additional RFP will be considered for up to 500 MW of accredited all-seasons capacity options that can be dispatched in times of need, compliment the intermittency of renewable resources, and demonstrates a technology pathway to be carbon-free in the future. As additional renewable energy penetrates the market, the need for cost-effective, responsive generation, which also has quick ramp up and ramp down capabilities, will be valuable for customers and the system. This RFP will contemplate the replacement for Brame Energy Center resources, including Nesbitt 1 as an aging less efficient gas asset facing potential significant upgrade costs associated with NOx compliance and emission objectives.

MISO Considerations

Cleco Power became a MISO member on December 19, 2013. Cleco Power will continue to actively participate in the MISO strategic, advisory, stakeholder, and owner groups as appropriate to remain current on market and other issues that are likely to affect MISO or Cleco Power. Cleco Power will also provide feedback to MISO along with other MISO member companies. Due to MISO's seasonal PRMR constructs and implications to Cleco Power, planning will be closely monitored and considered for planning purposes once finalized.

Environmental Considerations

Cleco Power will monitor existing and potential future environmental regulations and their accompanying required compliance measures. Exact measures to be taken for all potential or proposed rules are not absolute as of the filing of this Final IRP Report due to many of the rules remaining uncertain or in draft form at this time.

Conclusion

Cleco Power will continue to monitor load, peak demand, fuel prices, environmental regulations, and other key factors to ensure that its resource mix can adequately and reliably serve all customers. Material changes to these assumptions as more data becomes known may cause adjustments to the Action Plan. Cleco Power will work with regulators, customers, and stakeholders to ensure the safe, reliable, and economically efficient operation of Cleco Power resources.

Section 9: Stakeholder Feedback

Comments on IRP assumptions

Cleco Power received comments from various stakeholders after the filing of the Cleco Power IRP Assumptions. The following stakeholders publicly filed comments: the Louisiana Public Service

Commission staff ("LPSC Staff"), Advanced Energy Management Alliance ("AEMA"), Alliance for Affordable Energy ("AAE"), International Paper ("IP"), Sierra Club, Southern Renewable Energy Association ("SREA"), and Wärtsilä. Cleco Power considered all comments that were submitted. Comments made by stakeholders are paraphrased below, followed by Cleco Power's response.

Comment #	**1**
Comment	**Refresh fuel forecast to incorporate recent events, including fuel markets to make sure that they provide a realistic range of values for their forecasts.**
Stakeholder	LPSC Staff, IP, SREA, AAE
Response	Cleco Power updated its fuel assumptions and filed an updated assumptions document. The updated gas curves included a "constrained" gas scenario that is significantly higher than the prior "high gas" case.

Comment #	**2**
Comment	**Cleco should include a reasonable estimate of transmission costs in its pricing for supply side resources, particularly given that certain renewable resources are likely to be located remote from Cleco Power's load. Without a reasonable estimate of transmission costs being included in the pricing of supply side resources, Cleco Power's modeling of supply side resources will not reflect a reasonable estimate of the cost of the resources, which may result in uneconomic resource portfolios that are not consistent with lowest reasonable cost resource planning principles.**
Stakeholder	IP
Response	Cleco Power did not include any transmission costs for any technology to ensure consistency and reduce bias when modeling resource options. The topology of the transmission system and the generation sources and load sinks are dynamic, especially in future years. Transmission costs can vary significantly due to timing, location, and project specifics and will be included in any analysis completed during diligence of an RFP.

Comment #	3
Comment	**Cleco Power cross-test each resource portfolio against the assumptions in the other scenarios given that each scenario can have vastly different assumptions about how the future will look.**
Stakeholder	IP
Response	Cleco Power analyzed realistic scenarios that test resource optimization choices for the portfolio in a variety of futures. The scenarios and sensitivities selected provided tests and solutions when market price varies, load increases, load shapes change, carbon emission penalties occur, and market generation supply fluctuates with perfect information. Cleco Power will consider any scenarios or sensitivities proposed, if these scenarios or sensitivities are realistic and change variables that impact the market or optimization results in a manner differently than the range of futures put forth by Cleco Power.

Comment #	4
Comment	**10 years of historical load and demand information, annual total energy consumption by class, and monthly energy consumption by utility and customer class.**
Stakeholder	IP
Response	Cleco Power has provided this in the Draft IRP Report in Section 2 and Appendix 1.

Comment #	5
Comment	**Cleco should include in its Draft IRP for each scenario, whether Aurora would have retired a unit if the retirement assumption had not been hard-wired by Cleco. The Draft IRP should also include the capacity factor for each Cleco Unit resulting from the hourly Energy Model.**
Stakeholder	LPSC Staff
Response	Cleco Power allowed Aurora to retire all Cleco Power units as a part of the optimization logic. While Cleco Power did "hard-wire" some assumptions, including Rodemacher 2 retirement by 2028, Teche 3 exclusion from the study, and Madison reduction in load, these "hard-wires" did not limit

	Aurora's ability to retire those units sooner. This is addressed in Section 8 of the Draft IRP Report. Capacity factors can be found in Appendix 5.

Comment #	6
Comment	**Staff requests that Cleco also provide an analysis of the historical and going-forward costs for each of the existing supply side resources included in the going-in position. Should include transparent details of operating and maintenance costs, as well as addition capital costs, to include the cost of new equipment needed to comply with federal and state-level emissions requirements, especially for meeting potential requirements under CCR Rule and Effluent limitations Guidelines. Cleco should then convert the going-forward costs to a levelized cost of energy for each resource; Cleco should compare each LCOE to Cleco's forecast of energy prices in each of its scenarios. Draft IRP should then discuss Cleco's decisions whether to de-activate or retire each of its existing resources in the context of the "Going-forward LCOE" and energy prices as well as reliability and resource adequacy in each of Cleco's future scenarios.**
Stakeholder	LPSC Staff
Response	Please see Appendix 9 for analysis of the historical and going-forward costs for each of the existing, supply side resources included in the going-in position. Cleco Power's going-forward costs include any costs associated with compliance with federal and state-level emissions requirements.

Comment #	7
Comment	**Staff would like to see a sensitivity or scenario which reflects a low MISO energy price outlook (Could be postulated as world with a large influx of zero-marginal cost resources, wind and solar, into MISO and low natural gas prices).**
Stakeholder	LPSC Staff
Response	Cleco Power ran a low gas sensitivity that creates low market prices. Results are discussed in Section 8 of the Draft IRP Report.

Comment #	8
Comment	**Staff wishes to see a high MISO energy price scenario, and its impacts on the technology chose for MISO and Cleco's capacity expansion projections in Draft IRP.**
Stakeholder	LPSC Staff
Response	Cleco Power ran a "constrained" gas sensitivity which creates high market prices. The results of this scenario are discussed in Section 8 of the Draft IRP Report.

Comment #	9
Comment	**Staff requests that Cleco provide in the Draft IRP a detailed discussion and rationale for its High Load case (and whether it is equivalent to the Robust Growth Scenario); and transparency as to demand growth rate assumed in the Electrification Scenario.**
Stakeholder	LPSC Staff
Response	Cleco Power has omitted the "high load case" and replaced it with "base electrification" and "upside electrification." The assumptions for the electrification scenarios are summarized in Section 2 of the Draft IRP Report.

Comment #	10
Comment	**Cleco should include total historical peak load and total energy as well as the growth rate of load for Cleco for the past 10 years in its Draft IRP. Report by end-use sector (residential, commercial, industrial, etc.). Actual rate of growth assumed in the Base, High, and Low growth should be defined in transparent and quantitative terms. The role of customer counts, usage per customer, the customer segment, and role of incremental energy efficiency in driving peak load and energy consumption should be described, and annual tables of numbers for these drivers should be provided.**
Stakeholder	LPSC Staff

Response	Cleco Power has provided this in the IRP Draft Report in Section 2 and Appendix 1.

Comment #	**11**
Comment	**The historical annual results of the TOUCH program (in terms of impact on peak kW) should also be included in the draft IRP, along with projections of results going forward in each of Cleco's scenarios.**
Stakeholder	LPSC Staff, AEMA
Response	Three years of historic results for the TOUCH program is in Section 3 of the Draft IRP Report. Cleco Power does not forecast the effects of its TOUCH program, due to the program having immaterial changes to peak demand.

Comment #	**12**
Comment	**Report capacity factor for each Cleco unit resulting from the hourly energy model, and clearly report for each new Technology in Draft IRP. Staff would also like to see Cleco clarify the offer strategy for each of Cleco's units included in Aurora: DRAFT IRP should explicitly indicate which Cleco units are offered as must run, and which units are offered based on economics. Make any capacity addition limits explicitly known, and provide comparisons of the optimal capacity additions chosen by Aurora with and without caps on any given type of Supply-side resource.**
Stakeholder	LPSC Staff
Response	Please refer to the "Capacity Limits for Potential Resources" in Section 7 of the Draft IRP Report. Cleco Power's units were all dispatched economically.

Comment #	**13**
Comment	**Cleco should provide the 3rd party CO2 emissions costs assumptions.**
Stakeholder	LPSC Staff
Response	This was provided in Cleco Power's updated assumptions filing and is also included Section 7 of the Draft IRP Report.

Comment #	14
Comment	**In Draft IRP, Cleco provide specific and transparent assumptions about the volume of existing supply capacity and capacity additions, by type of technology, for MISO as a whole (not just Cleco) which are incorporated into the MISO energy Model.**
Stakeholder	LPSC Staff
Response	Please see Appendix 7 – MISO South Fuel Mix, which provides the generating capacity of the MISO South units, inclusive of Cleco Power.

Comment #	15
Comment	**Section 5 of IRP rules regarding Transmission; planning study needs to be provided. Identify and describe significant transmission constraints and limitations within its system and identify and describe any Reliability must run units that it operates. Discuss any actions that could be taken to eliminate the constraints, limitations, and RMR units. Cleco needs to examine and transparently present the cost of transmission alternatives, and provide information related to the topology of Cleco's footprint and relevant interconnections with other MISO areas, in Draft IRP. This is needed to achieve a holistic view of future transmission and generation needs.**
Stakeholder	LPSC Staff, SREA
Response	Please refer to Section 5 of the Draft IRP Report.

Comment #	16
Comment	**Staff request that Cleco include exactly which EIA demand outlook it uses in each of Cleco's Base Gas, High Gs, and Low Gas outlooks. EIA produces many Annual Energy Outlook each year, and staff would like transparency in Cleco assumptions. Staff would like to see Cleco's assumptions for growth of LNG demand in each of Cleco's scenarios.**
Stakeholder	LPSC Staff

Response	Cleco Power relied on fuel forecast from Filsinger Energy Partners ("FEP"). FEP's forecast is inclusive of EIA data and LNG exports. Please refer to Section 4 of the Draft IRP Report.

Comment #	17
Comment	**AEMA recommends an implementation of Order 2222 be made clear in the scenarios for the IRP - mandates DERs be able to fully participate in all wholesale markets.**
Stakeholder	AEMA
Response	Cleco Power has not seen any noticeable contribution to the wholesale market by DERs, therefore chose not to include in the Aurora model.

Comment #	18
Comment	**Include detail around pending federal policies that are poised to provide significant funding to communities and utilities for resilience and other flexibility upgrades to the electric grid.**
Stakeholder	AEMA
Response	Cleco Power is currently analyzing how to properly utilize the "Inflation Reduction Act" to benefit its customers. Cleco Power will include further detail regarding its treatment of the "Inflation Reduction Act" in its Final IRP Report.

Comment #	19
Comment	**Would be useful in at least one scenario additional tax incentives for microgrids, interconnection, and bonus credits for deployment in low-income communities.**
Stakeholder	AEMA
Response	Cleco Power did not include this as a scenario but is considering how to use investment/production tax credits to better serve and benefit its customers.

Comment #	20
Comment	**Cleco needs to use a comprehensive modeling tool that looks at supply and demand side resources; AEMA recommends using "Vibrant Clean Energy WIS:dom P tool."**
Stakeholder	AEMA
Response	Cleco Power has successfully relied on Aurora for its resource planning needs and will continue use to Aurora for this IRP cycle and future RFPs.

Comment #	21
Comment	**Include demand-side resources as part of available capacity.**
Stakeholder	AEMA
Response	Cleco Power has included energy efficiency and demand response as a potential resource.

Comment #	22
Comment	**Wärtsilä wants to Cleco to include a reciprocating internal combustion engine as a potential resource.**
Stakeholder	Wärtsilä
Response	Cleco Power gained access to Wärtsilä's online portal to more accurately portray reciprocating engines.

Comment #	23
Comment	**Recommends Cleco include modeling scenarios that achieve its 60% by 2030 and 2050 net-zero carbon dioxide goals.**
Stakeholder	Wärtsilä
Response	Cleco Power did not explicitly model a 60% reduction by 2030. Cleco Power is working towards this goal by the retirement of Dolet Hills Power Station, the retirement of Rodemacher 2, the retirement of Teche 3, carbon-capture

	and sequestration at Madison 3, and the Dolet Hills Solar Project, which results in a substantial reduction.

Comment #	**24**
Comment	**Use NREL ATB to add PPA options into Aurora; Cleco should enable offshore wind resources to be added to the model in 2028 and afterward. (Also, for all wind, solar, hybrid, and any other resources in dataset).**
Stakeholder	SREA, Sierra Club
Response	Cleco Power used EIA data for new resources, which include solar, on-shore wind, off-shore wind, and solar with battery storage. Cleco Power is currently seeking approval of a solar PPA with Dolet Hills Solar, LLC, a project company subsidiary of D.E. Shaw Renewable Investments, LLC in LPSC Docket No. U-36502 for approximately 240 MW of power. Based on market surveys that Cleco Power obtained for solar PPA pricing in the Midcontinent Independent System Operator, Inc. ("MISO") footprint for the second quarter of calendar year 2022, the pricing under the solar PPA is very favorable relative to the market pricing. Please see filings made in LPSC Docket No. U-36502 for additional details. At the Commission's September 21, 2022 Business and Executive session, Commissioner Greene issued a directive for each electric utility to provide an evidentiary record of all costs and benefits associated with power generation and resource supply from offshore wind for Louisiana utilities, including the utilities' data assumptions and any customer impacts of offshore wind being utilized now or in the future for the utility resource portfolio. In the renewable category, offshore wind has been removed as a potential resource option in this Draft IRP, due to significantly higher cost estimates than all other renewable resource options. However, given Commissioner Greene's directive, above, Cleco Power will continue to analyze possible incorporation of offshore wind into its resource portfolio and will present its findings in Cleco Power's Final IRP.

Comment #	25
Comment	**The company should include renewable LCOE's so stakeholders and the LPSC can evaluate the reasonableness of the underlying data input assumptions, before running the models.**
Stakeholder	SREA
Response	LCOE for renewable resources are provided in Section 7 of Draft IRP Report.

Comment #	26
Comment	**Provide renewable energy capacity values that will be modeled in aurora. Also, Cleco should not give any units a set capacity value, but see how the model would perform if they weren't constrained.**
Stakeholder	SREA
Response	Cleco Power modeled solar PPAs with a nameplate capacity of 100 MW; solar self-build with a nameplate capacity of 150 MW; and wind PPAs with a nameplate capacity of 200 MW. These were assigned a peak credit to solar of 50% and a peak credit to wind of 30%. The capacity value that is assigned to units has no effect on how the units dispatch in the model.

Comment #	27
Comment	**Cleco should begin to develop seasonal capacity accreditation for its existing generation units, as well as new build generation technology.**
Stakeholder	SREA
Response	Seasonal capacity accreditation will not be included in this Draft IRP Report. MISO is still finalizing the seasonal capacity accreditation methodology, and Cleco Power is still analyzing how to use MISO's 2023/24 PY Planning Reserve Margin to plan for seasonal accreditation. Below is link to MISO's presentation regarding the 2023/24 PY Planning Reserve Margin:

	https://cdn.misoenergy.org/20221003%20LOLEWG%20Item%2003%20PY%202023-24%20Final%20LOLE%20Study%20Results626468.pdf

Comment #	28
Comment	**Use MISO MTEP Futures: Cleco could simply take the hourly LMP data from MISO's MTEP Futures 1, 2, and 3 and use those data, directly. This would significantly reduce Cleco's time burden, while increasing accuracy to better align with the MISO market.**
Stakeholder	SREA
Response	MISO's MTEP Futures LMPs are not accurately calculated for each scenario Cleco Power performed. Since assumptions are dynamic, Aurora calculates hourly LMP for each run specific to each scenario and sensitivity.

Comment #	29
Comment	**Capacity Planning is Fatally Flawed: Create a "manual Portfolio that manually" adds lower cost renewable energy resources, and then evaluate the net cost benefit of those additions. Cleco can input earlier retirement dates for its existing generation units to create a capacity need. (SREA)**
Stakeholder	SREA
Response	Key modeling parameters used to determine resource needs include capacity requirements and economic viability in the market. These parameters are used for all resources being evaluated.

Comment #	30
Comment	**Cleco Should Test Earlier Retirement of Solid-Fuel Units and commit to a 2028 retirement of Rodemacher 2.**
Stakeholder	Sierra Club
Response	Aurora was allowed to retire all Cleco Power units in the model.

Comment #	31
Comment	**Cleco should commit to issue an all-source RFP that is constructed to consider all resource types and to allow for effective competition in this IRP.**
Stakeholder	Sierra Club
Response	Cleco Power has selected a diverse portfolio of demand and supply side resources to be evaluated in this IRP. As the need for an RFP is determined, Cleco Power will issue an RFP based off the needs and the resources that can fulfill those needs at that point in time. Cleco Power maintains that it is premature to commit to terms for future RFPs.

Comment #	32
Comment	**Cleco should clearly evaluate its over-capacity and NRG South Acquisition Risk.**
Stakeholder	Sierra Club
Response	This is an IRP for Cleco Power, which is a separate entity from Cleco Cajun. Cleco Power must plan for its own energy and reserve margin requirements.

Comment #	33
Comment	**Cleco should analyze public health impacts.**
Stakeholder	Sierra Club
Response	Cleco Power will not address social costs in the IRP Report.

Comment #	34
Comment	**Project Diamond Vault: is the output from Madison Power Station 3 going to be dedicated to third parties once the project is complete and are those third parties currently retail customers of Cleco Power and included in Cleco Powers current load or load projections?**

Stakeholder	IP
Response	Project Diamond Vault is in the early stages of planning, and this matter has not yet been determined. In the IRP modeling, there was no increase or decrease to load for potential third-parties.

Comment #	**35**
Comment	**If Cleco Power is not successful in selling the output of MPS3 to third parties after the project is complete, what is the impact on Cleco Power's retail customers – with respect to cost recovery and resource planning?**
Stakeholder	IP
Response	Project Diamond Vault is not expected to increase customer rates.

Comment #	**36**
Comment	**Cleco should run at least three scenarios where CCS is not added, and instead Madison 3 is retired by 2030, or earlier.**
Stakeholder	SREA
Response	Cleco Power ran CCS at Madison 3 in all scenarios with Madison losing 200 MW of generating capacity. The recent passage of the "Inflation Reduction Act" incentives Cleco Power to move forward with Project Diamond Vault and move towards a cleaner generating portfolio.

<u>Comments on Draft IRP</u>

Cleco Power received comments from various stakeholders after the filing of the Cleco Power Draft IRP. The following stakeholders publicly filed comments: the Louisiana Public Service Commission Staff, Advanced Energy Management Alliance, Sierra Club, Southern Renewable Energy Association, and Wärtsilä. Cleco Power considered all comments that were submitted. Comments made by stakeholders are paraphrased below, followed by Cleco Power's response.

Comment #	**37**
Comment	**Cleco's proposal to retrofit Madison 3 with CCS without any evidence that the CCS project is part of a least-cost portfolio of resources for**

	ratepayers or that it is the best low-carbon option for the Company. Cleco included the Diamond Vault project in all scenarios, meaning it did not model any scenarios without the CCS project. The assumption that CCS is part of the baseline future is premature and concerning given that the project needs to receive approval from the Commission and likely many other regulatory bodies. Furthermore, the Diamond Vault project is likely to face many regulatory, technological, and financial challenges that make it a risky investment for the Company.
Stakeholder	Sierra Club
Response	Cleco Power must make assumptions during the integrated resource planning process. It is not feasible or practical for Cleco Power to evaluate the economic and technical aspects of Project Diamond Vault and its impact upon Madison 3 until the conclusion of the FEED study. It is prudent for Cleco Power to take the steps necessary to evaluate Project Diamond Vault and its impact upon Madison 3, allowing for a thorough examination of costs, benefits, and risks, through the FEED study. Upon completion of the thorough examination contemplated by the FEED Study, Cleco Power will review the results with all appropriate stakeholders and regulators. Making an assumption regarding Project Diamond Vault in this IRP Report does not represent any firm plans for the project, and does assuredly not replace or bypass the regulatory processes currently in place, including specifically those of the Commission.

Comment #	38
Comment	**Cleco has not performed any capacity expansion modeling to evaluate reasonable alternative resource options to CCS; it has not evaluated alternative financial mechanisms for addressing the remaining book value at Madison 3; it failed to consider the environmental compliance risks associated with the continued operation of Madison 3; and the Company has not evaluated whether there are other cost-effective resources that can achieve the utility's greenhouse gas reduction goals.**
Stakeholder	Sierra Club
Response	Cleco Power performed capacity expansion modeling that included many resource alternatives. As noted above, CCS at Madison Unit 3 will be evaluated for prudency after the FEED study is complete.

Comment #	39
Comment	**Prior to seeking approval for the Madison 3 CCS project, Cleco should be required to provide the following information to the Commission: (1) which well it intends to rely on; (2) how much it will cost to complete the regulatory approval process, dig the well, maintain it, and close it at the end of its useful life; and (3) the extent to which it expects ratepayers to bear the associated cost and risk – including costs relating to Class VI bonding requirements and ongoing post-injection monitoring as required by the EPA.** **If Cleco decides to move froward with the Diamond Vault project despite the associated risks and uncertainties, we recommend that Cleco commit to seeking preapproval for the project and provide the Commission and stakeholders with a timeline for seeking that preapproval.**
Stakeholder	Sierra Club
Response	Cleco Power will provide all necessary support and findings during the appropriate regulatory proceedings. Again, making an assumption in this IRP Report does not represent any firm plans for Project Diamond Vault and does not replace or bypass the regulatory processes currently in place, including those of the Commission.

Comment #	40
Comment	**Cleco should share the results of the FEED study publicly and provide clarity on the footprint required for the CCS project.**
Stakeholder	Sierra Club
Response	The FEED Study is being funded by a congressional appropriation and is being administered by the Department of Energy. As such, the non-confidential results from the FEED study will be made public at the end of the project in accordance with the requirements of the cooperative agreement with the Department of Energy for the project.

Comment #	**41**
Comment	**Cleco should outline the potential for future likely environmental controls at Madison 3, evaluate the cost of these controls and regulations, and assess their impact on plant operations. Cleco should then factor these costs into its future analysis.**
Stakeholder	Sierra Club, SREA
Response	Relative to Project Diamond Vault, Cleco Power will provide all necessary support and findings during the appropriate regulatory proceedings. Cleco Power will include all costs and controls in all future analysis once the FEED study is complete. Reference is made to Section 6 of this IRP Report of a discussion of potential future environmental regulations that may impact operations at Madison Unit 3.

Comment #	**42**
Comment	**Cleco should model scenarios in its final IRP that allow the model to select between retirement (and replacement with alternatives), conversion to gas, and CCS retrofit at Madison 3.**
Stakeholder	Sierra Club
Response	The Aurora model was allowed to retire Madison 3 in all scenarios, but only chose to do so in two sensitivities (Upside Electrification with Low Gas, Reference Load with low gas; both in 2039). Cleco Power did not consider a gas conversion of Madison 3 in this IRP.

Comment #	**43**
Comment	**Cleco should fully evaluate in its final IRP the securitization of any remaining plant balance at Madison 3 as an alternative to retrofitting Madison 3 with CCS, and then recycle the bond proceeds into renewable assets on its balance sheet. Cleco should fully evaluate securitization options that can help ameliorate community impacts associated with early retirement.**
Stakeholder	Sierra Club

Response	The Aurora model was allowed to retire Madison 3 in all scenarios, but only chose to do so in two sensitivities (Upside Electrification with Low Gas, Reference Load with low gas; both in 2039). Recovery of Madison 3 costs (or the cost of any other assets not identified for retirement) through securitization was not modeled in this IRP. Until the FEED study is complete, it is premature at this point to consider securitization for Madison 3.

Comment #	44
Comment	**Cleco should also re-evaluate its cost assumptions, particularly for offshore wind, and benchmark its costs against similar utilities and recent RFP responses.**
Stakeholder	Sierra Club
Response	Cleco Power compared the publicly available EIA renewable resource pricing assumptions to NREL's pricing assumptions and updated the offshore wind cost assumptions to reflect NREL pricing. Cleco Power is not aware of any comparable wind projects in the Gulf of Mexico. All other renewable pricing assumptions were within reason between the sources.

Comment #	45
Comment	**Cleco should conduct its resource planning efforts and future procurement processes in a way that does not systematically favor gas and disfavor clean energy resources.**
Stakeholder	Sierra Club
Response	Cleco Power disagrees with this premise. First, it should be noted that the Action Plan specifically recommends the addition of up to 500 MW of clean energy resources, which are in addition to the 240 MW of solar resources under the Dolet Hills Solar PPA currently pending Commission authorization in LPSC Docket No. U-36502. Cleco Power conducts its resource planning comprehensively and objectively, and does not conduct its planning to achieve a preconceived outcome. Cleco Power does not systematically favor gas resources and disfavor clean energy resources; however, as an electric public utility with a public interest mandate to provide reliable power, the Company

	has an obligation to consider a diversified portfolio that balances considerations of reliability and affordability.

Comment #	46
Comment	**Include demand side resources as clean, cost-effective, resilient capacity resources that can contribute to the system capacity needs in Cleco's proposed 500 MW RFP plans.**
Stakeholder	Advanced Energy Management Alliance
Response	**Cleco Power included Energy Efficiency and Demand Response as a resource alternative in all modeling scenarios for the IRP. The final aspects of the RFP(s) have not been finalized, but will be determined during the RFP process.**

Comment #	47
Comment	**Account for potential of more rapid deployment and expansion of DERs from implementation of Order 2222.**
Stakeholder	Advanced Energy Management Alliance
Response	Cleco Power is closely monitoring MISO's compliance with FERC Order No. 2222. MISO implementation date for Order 2222 is expected to be in the 2030 timeframe.

Comment #	48
Comment	**Include heat pumps and other electrification technologies beyond electric vehicles.**
Stakeholder	Advanced Energy Management Alliance
Response	Cleco Power is considering other electrification technologies. It should be noted, however, that Cleco Power believes that electrification of transportation will provide the most substantial public benefit versus other electrification technologies which may be more incremental in nature.

Comment #	49
Comment	**Consult with private sector companies that have expertise in DERs as well as deriving information from DER Case Studies white paper.**
Stakeholder	Advanced Energy Management Alliance
Response	Cleco Power consulted with DNV Energy and included programmatic Demand Response Program costs and customer participation estimates. Cleco Power will likely consider additional studies and information to assess value.

Comment #	50
Comment	**Ensure modeling tools fully value the benefits of DERs to the system.**
Stakeholder	Advanced Energy Management Alliance
Response	Cleco Power utilized Aurora as its modeling tool and included inputs associated with demand side management costs and the resulting load conservation.

Comment #	51
Comment	**Cleco should also provide the peak demand data behind Figure 2.1, which includes all three cases**
Stakeholder	LPSC Staff
Response	Peak demand data can be found in Appendix 1: Monthly Energy and Peak Demand.

Comment #	52
Comment	**Clearly define each portfolio which will be tested, providing all costs, unit MW sizes, commercial online year, fixed costs, impact of IRA, variable costs, etc., sufficient to support an LCOE analysis of the cost of the portfolios.**
Stakeholder	LPSC Staff

Response	Section 7 contains the updated modeling assumptions that describe the capital costs, MW size, fixed costs, variable costs, and impacts of the IRA for renewable resources. Section 7 also contains the capital costs, MW size, fixed costs, and variable costs for potential natural gas-fired resources. Section 8 defines the portfolios that were tested and includes the commercial online year assumptions for the Optimized Portfolio. Appendix 6 contains discrete commercial online year assumptions for the Reference Portfolio and Upside Portfolio. Appendix 10 contains the LCOE analysis of the cost of each portfolio.

Comment #	**53**
Comment	**Provide cost assumptions for transmission for each technology, if any**
Stakeholder	LPSC Staff
Response	Incremental transmission costs are project and location specific. Cleco Power did not speculate regarding transmission costs, or apply transmission costs that may or may not have a basis in reality, to any new resource options. Transmission costs will be included within RFP evaluations, in which transmission information is included as part of the RFP evaluation to assess potential transmission upgrades that may impact proposed projects.

Comment #	**54**
Comment	**Cleco should provide the Electrification study to assist Staff and stakeholder's efforts to understand the drivers of Cleco's Load forecast.**
Stakeholder	LPSC Staff, SREA
Response	The electrification study contains proprietary, commercially-sensitive market information. Further, the electrification study was conducted by a third-party vendor, and Cleco Power is subject to a binding confidentiality agreement with that party specifically covering the study. The third-party vendor has not consented to disclosure of the study.

Comment #	55
Comment	**Cleco must include the impacts of the IRA's Production Tax Credit and the Investment Tax Credit for renewable resources.**
Stakeholder	LPSC Staff; Sierra Club, Advanced Energy Management Alliance, SREA
Response	Cleco Power has updated the resource assumptions to reflect the IRA. Table 7.3a and 7.3b shows the $/kW for renewable resources with PTC and ITC, inclusive of offshore wind. The $/MWh LCOE numbers can be found on Table 7.5. While election of ITC or PTC is ultimately a decision that will be evaluated and elected when the Company files its tax return, after a project's commercial operation date. Cleco Power has addressed the stakeholder comments by providing the updated assumptions.

Comment #	56
Comment	**Cleco must provide the UCAP and ICAP annual total capacity for each scenario and sensitivity that were provided in Appendix 7.**
Stakeholder	LPSC Staff
Response	Appendix 7 contains the installed capacity amounts by fuel type for each scenario. Cleco Power's beginning capacity for MISO South that was used for modeling in Aurora was referenced to the EIA Form 860-M data for March 2023.

Comment #	57
Comment	**Cleco should explicitly explain how to incorporate capacity accreditation into the portfolio analysis.**
Stakeholder	LPSC Staff and SREA
Response	Cleco Power has incorporated seasonal accreditation to its units (and all units in within MISO) for this analysis based. Please refer to Appendix 4 – SAC values for detail about Cleco Power units.

Comment #	58
Comment	**Cleco should report its current carbon footprint and the carbon footprint of each of the portfolios in each of the scenarios.**
Stakeholder	LPSC Staff
Response	Please see Appendix 5.2, 5.3, 5.4, and 5.5 which contains the carbon emissions and carbon intensity for each the of long-term buildouts, Portfolio 1 (reference portfolio), Portfolio 2 (upside electrification portfolio), and the Optimized Portfolio in each scenario.

Comment #	59
Comment	**Provide clear explanations for all DR and EE assumptions; ensure they are consistent with energy prices for each future and consistent with results of DSM study; be explicit as to the impact of DR and EE on each load forecast and scenario. Compare the costs of DR and EE to the LCOE of supply alternatives in its selection of the least-cost portfolio to meet reliability requirements.**
Stakeholder	LPSC Staff
Response	Please see Table 7.4: Demand Response and Energy Efficiency in section 7 of the IRP report.

Comment #	60
Comment	**Do not force Project Diamond Vault (or any new resource) into every portfolio and every scenario-projects must compete on economics. Do not offer based on self-schedule in Aurora.**
Stakeholder	LPSC Staff
Response	Cleco Power did not force any new resources into any portfolios or scenarios. Project Diamond Vault is an assumption in this IRP, and contemplates the potential need for capacity replacement for a portion of Madison Unit 3. Project Diamond Vault is effectively the same as any load assumption submitted in this IRP. As noted above, the FEED study will assess the economic and technical aspects of Project Diamond Vault. If Cleco Power

	elects to move forward with the project, there will be separate dedicated regulatory proceedings to consider whether the project is in the public interest.

Comment #	**61**
Comment	**Assume only generic new resources, do not name a specific vendor.**
Stakeholder	LPSC Staff
Response	Cleco Power used a combination of EIA and NREL publicly sourced data at the request of stakeholders. One stakeholder provided technology-specific data for modeling purposes, as part of the collaborative process that the IRP Order specifically contemplates.

Comment #	**62**
Comment	**Examine MISO resource assumptions and improve consistency with current data; improve consistency with scenario stories**
Stakeholder	LPSC Staff
Response	MISO resource assumptions have been examined and are consistent with MISO. Please see Appendix 7: MISO South Fuel Mix.

Comment #	**63**
Comment	**Quantifying the value of the key elements of dispatchability (start-up, minimum run time, minimum down time, minimum operating level, ramp speed, duration) is necessary to optimize future procurement decisions.**
Stakeholder	Wärtsilä
Response	Cleco Power recognizes there is value in quick start units in an energy market that is heavily relying on intermittent resources. However, Cleco Power did not utilize sub-hourly dispatch it its modeling due to time and resource constraints. Cleco Power will consider sub-hourly dispatch in future RFPs.

Comment #	**64**
Comment	**Cleco's Action Plan need firm milestones**
Stakeholder	SREA
Response	Please see the updated Action Plan in Section 8 of the IRP report.

Section 10: Appendices

Appendix 1: Monthly Energy and Peak Demand
Appendix 2: Commodity Price Projections (Confidential)
Appendix 3: Cleco DSM Potential Study Report
Appendix 4: SAC Values (Confidential)
Appendix 5.1: Long-Term Buildout FCA and CO_2 Data (Confidential)
Appendix 5.2: Reference Portfolio FCA and CO_2 Data (Confidential)
Appendix 5.3: Upside Portfolio FCA and CO_2 Data (Confidential)
Appendix 5.4: Optimized Portfolio FCA and CO_2 Data (Confidential)
Appendix 6: Cleco Fuel Mix Charts for Long-Term Buildouts
Appendix 7: MISO South Fuel Mix
Appendix 8: Reserve Margin for Long-Term Buildout Scenarios
Appendix 9: Existing Generation Revenue Requirements (Confidential)
Appendix 10: Portfolio Evaluation and Testing (Confidential)
Appendix 11: Modeling Results
Appendix 12: Acronyms