Cleco Power LLC
2025 Interim Integrated Resource Plan
Report

September 5, 2025

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Section 1: Executive Summary

Overview

This Interim Integrated Resource Plan ("IRP") Report (this "Interim IRP Report") has been developed, and is being filed with the Louisiana Public Service Commission (the "LPSC" or the "Commission") in accordance with, certain "Environmental and Dispatch Commitments" that were agreed upon by Cleco Power LLC ("Cleco Power" or the "Company") and the parties to LPSC Docket No. U-36923[1] pursuant to an Uncontested Proposed Stipulated Settlement entered into effective as of May 30, 2024, which the Commission subsequently authorized in Order No. U-36923, issued July 17, 2024. Please refer to Order No. U-36923 at pp. 13-15.

Accordingly, while this Interim IRP Report is intended in part to address Cleco Power's analyses of resource planning options and alternatives for its Madison Unit 3 ("Madison 3" or "MPS3") and Rodemacher Unit 2 ("Rodemacher 2" or "RPS2") electric generating units ("EGU") as contemplated by the Environmental and Dispatch Commitments, an overarching objective is to consider Cleco Power's generating fleet holistically through the lens of reliability and to analyze alternative resource planning scenarios that would maintain and potentially improve reliability. As discussed in this executive summary and in comprehensive detail below, Cleco Power maintains that an intense focus on reliability, given the current dynamic energy market, particularly in the Midcontinent Independent System Operator, Inc. ("MISO") Local Resource Zone 9 ("LRZ 9"), is critical from the perspective of ensuring that Cleco Power has sufficient capacity and energy on a going-forward basis to reliably serve its customers in a cost-effective manner.

While Cleco Power agreed to develop this Interim IRP Report (as discussed above), the objective of Cleco Power in this filing is to provide reliable, resilient, and affordable power to satisfy the needs of the Company's customers and preserve our community's quality of life. This has been and remains the ultimate goal of the Company, its employees and its Owners. Customer reliability is driven by both the grid (bulk power and distribution system) and the utility's generation fleet to collectively meet community, industry, and customer demands. Affordability and reliability can conflict as investment in generation and grid elements may increase customer costs. Cleco Power's role as the load serving entity in the Louisiana regulated business climate is to optimize the Company's investments in reliability and the affordability of the electric product the Company provides. This Interim IRP is Cleco Power's method to optimize such investments in reliability to ensure the lowest reasonable cost of reliable service to the Company's customers.

This Interim IRP Report identifies a "Preferred Portfolio" designed to provide reliable capacity and energy at the lowest reasonable cost to the Company's current customers with consideration for upside-load growth. However, the rapid growth of data centers, industrial, and other large load opportunities provides a significant potential to increase the Company's load requirements, and would require an update to this Interim IRP. The near-term resources provided in the Preferred Portfolio would nonetheless still be required and would be encompassed in such an update.

[1] LPSC Docket No. U-36923, Cleco Power LLC, ex parte. *In re: Request for: 1) implementation of change in rates with an effect date of July 1, 2024; and 2) extension of existing Formula Rate Plan.*

In addition, and in connection with the reliability focus of this Interim IRP Report, under the Commission's General Order (Corrected) in Docket No. R-30021, issued April 18, 2012 (the "IRP General Order"), a utility *"may submit an updated IRP prior to the required submission of its next IRP. Reasons that might warranty the utility considering submitting an updated IRP include: i) It anticipates submitting an application for a certificate to construct or purchase a supply-side or demand-side resource that was not previously included as part of the IRP."* (*see* IRP General Order, Attachment A, Rule 11, p. 19).

As discussed more fully below, as part of its "Preferred Portfolio" presented in Sections 8 and 9, Cleco Power is proposing the addition of a combined cycle gas turbine ("CCGT") generating unit and maintains that it is therefore appropriate to update its most recent IRP in LPSC Docket No. I-36175 for this purpose.

Cleco Power intends to:

- Add approximately 700 megawatts ("MW") of dispatchable generation through the issuance of a request for proposals ("RFP") for accredited all-seasons capacity options that can be dispatched to reliably match customer demand and energy requirements. The 700 MW is inclusive of the 500 MW of dispatchable resource needs identified in Cleco Power's 2021 IRP Report, and is needed to:
    - mitigate a rapidly changing resource adequacy construct in MISO, which has significantly increased uncertainty and volatility since the Final 2021 IRP Report was filed in LPSC Docket No. I-36175;
    - reliably meet potential customer growth requirements; and
    - mitigate the risk of an unexpected loss of an aged generator (see the discussion on this point under "Internal Factors," below).
- Co-fire Madison 3 with natural gas to retain the capacity and energy from a 15-year-old electric generating unit ("EGU") that has 35 years of recoverable depreciable life remaining, which enables the unit to remain online beyond December 31, 2031, in accordance with Clean Air Act 111(d) best system of emissions reductions ("BSER") requirements.[2] If Clean Air Act 111(d) BSER requirements were to be rescinded, co-firing Madison 3 provides the option for fuel diversity.
- Repower Rodemacher 2[3] to be fired with natural gas to retain the capacity and energy from an existing EGU in a market with minimal uncontracted generation and at a lower cost than constructing a new generating unit or contracting for multiyear firm capacity.[4]

<u>Resource Planning Factors</u>

In this Interim IRP Report, Cleco Power has identified the factors, both internal and external to Cleco Power, that are currently having or will in the future have a material impact upon Cleco

[2] *See* Standards of Performance 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 Electric Generating Units; Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (to be codified at 40 C.F.R. pt. 60).

[3] Cleco Power owns 30% of Rodemacher 2. The remaining 70% is owned by Lafayette Public Power Authority and the Louisiana Energy & Power Authority (50% and 20% ownership, respectively).

[4] Based on market pricing obtained informally by Cleco Power.

Power's ability to reliably serve its customers. Based on the analyses conducted in the Interim IRP, Cleco Power has identified a Preferred Portfolio that would achieve the Company's objective of providing reliable power to its customers. This Interim IRP Report will serve as an update to Cleco Power's Final 2021 IRP Report filed in LPSC Docket No. I-36175 and as a bridge to Cleco Power's next full IRP under the Commission's IRP General Order. Cleco Power's next IRP cycle under the Commission's IRP General Order will initiate in October 2025, beginning with the filing of the Company's IRP assumptions and associated data.

<u>Internal Factors</u>

There are three primary internal factors impacting Cleco Power's ability to reliably serve its customers on a going-forward basis.

- Cleco Power's aging generation fleet: Cleco Power engaged 1898 & Co. to conduct a "Useful Life Assessment" of the Company's EGUs. In particular, with respect to Rodemacher 2, 1898 & Co. noted that Rodemacher 2 has been in commercial operation since 1982, giving it a current operational age of 43 years. In comparison to comparable coal-fired boiler units, Rodemacher 2 is currently within the 19% cohort of such units still in operation; that is, only 19% of comparable coal-fired boiler units of Rodemacher 2's vintage still remain operational. 1898 & Co. conducted a similar analysis for Cleco Power's other EGUs, identifying the design life of the units relative to comparable units in operation, and the typical large milestone capital projects to replace the major components of such units.
- Current environmental regulations impacting the operation of Cleco Power's generation fleet (in particular Madison 3 and Rodemacher 2): This Interim IRP Report analyzes the impact of current Clean Air Act Section 111 BSER requirements on Madison 3 and the impact of the current Coal Combustion Residuals ("CCR") Rule and the current Effluent Limitations Guidelines ("ELG") upon Rodemacher 2 in connection with future resource planning alternative scenarios for these units.
- Potential load growth within Cleco Power's service territory: Over the last few IRP cycles, Cleco Power's load growth has been relatively flat, but that has the potential to change significantly over the coming few years, driven by potential increases in commercial and industrial load.

<u>External Factors</u>

As noted previously, the current energy markets are dynamic and volatile, and there are several factors external to Cleco Power that will impact Cleco Power's resource planning, with Cleco Power's primary focus being on maintaining reliability. These factors impacting reliability include but are not limited to:

- Capacity constraints within LRZ 9: At present, there is little uncontracted capacity available in LRZ 9, and, based on indicative pricing that Cleco Power has obtained informally, the capacity that is available has become extremely expensive.
- Volatility introduced by MISO's seasonal accredited capacity ("SAC") construct: MISO's SAC construct has injected significant uncertainty into the appropriate planning reserve

margin that Cleco Power must maintain; the capacity allocation can swing materially from season to season as well as from year to year, by hundreds of MW.

- The increase in emergency events affecting both Cleco Power's service territory and MISO South: An additional factor impacting Cleco Power's resource planning is the significant increase in emergency events declared by MISO. Cleco Power has experienced an 81% increase (almost double) in declared emergency events from 2024 to 2025 (although 2025 is a partial year), primarily driven by severe weather and conservative operations. Meanwhile, MISO South experienced an astonishing 133% increase (more than double) in declared emergency events during this time frame, primarily driven by a surge in capacity advisories and severe weather declarations. The capacity advisories suggest that the system is frequently operating near its limits, especially during summer peak demand periods. It further suggests that reserve margins are tightening and that the grid is under increasing pressure to meet load requirements. Data illustrating the year-over-year increases in emergency events is provided in Section 5, below.
- Excessively long MISO interconnection queue and supply chain constraints: New generation in MISO's interconnection queue has increased tremendously over the past few years due to the oversaturation of project developers speculatively placing projects into the queue in the hope of developing a project before a power off taker is even identified, many of which projects are never brought to fruition. OEM turbine manufacturers have an ever-increasing queue and lead time (now potentially several years or more) for new turbines, with manufacturers now requiring significant upfront reservation payments to obtain a queue position in the manufacturing process.

The North American Electric Reliability Corporation ("NERC"), in its "2025 ERO Reliability Risk Priorities Report," issued August 14th, 2025,[5] identified the following "2025 Risk Themes" that will affect transmission system planning and operations:

- New large loads plus changing resource mix: The convergence of new large loads at unprecedented scale and speed, combined with new system operating experiences from an evolving resource mix, highlights the need to advance the traditional system reliability construct from capacity to energy based, and more detailed analysis of resources and load centers.
- Large-scale widespread events observed: Large-scale reliability impact events are occurring with contributions from grid transformation effects and increased incidence of large, widespread, long-term weather system scope, severity, and duration.
- Natural gas interdependence: The natural gas pipeline infrastructure (natural gas being the primary source of fuel to the dispatchable generation fleet in the next five years) must expand to meet the growing need of these new dispatchable generation units.
- Cyber and Physical Security Complexity: The growing complexity of system equipment and operations increases security challenges and enhances the attractiveness of the grid as a target.
- Persistent supply chain challenges: Persistent supply chain and workforce challenges are impacting risk mitigation and response capabilities.

[5] https://www.nerc.com/comm/RISC/Related%20files%20DL/2025_RISC_ERO_Priorities_Report.pdf

- Volatile energy policy: A volatile and disconnected policy landscape creates risks and further complicates the ability to mitigate risk through policy solutions.

The Preferred Portfolio as Cleco Power's Proposed Solution

After carefully analyzing the factors outlined above and described in comprehensive detail below, and after modeling a number of alternative scenarios, also described in comprehensive detail below, Cleco Power has identified a Preferred Portfolio. The Preferred Portfolio is identified as Portfolio 2 in Section 8, below. Cleco Power maintains that the Preferred Portfolio provides a cost-effective and rational means to address Cleco Power's going-forward capacity requirements, with a primary emphasis on ensuring reliable service to its customers.

The Preferred Portfolio includes the following elements:

(i) Conversion of Madison 3 from using petroleum coke ("petcoke") to fire generation to co-firing generation using 55% natural gas/45% solid fuel, by January 1, 2030;
(ii) Conversion of Rodemacher 2 from using coal to fire generation to using 100% natural gas to fire generation, by the end of 2027; and
(iii) Construction of a new combined cycle gas turbine ("CCGT") generating unit with a target commercial operation date by 2033.

The Preferred Portfolio elements are described more fully below. Additionally, described below are the actions that Cleco Power would undertake to implement the Preferred Portfolio.

Regulatory Background

This Interim IRP Report is the seventh IRP report developed by Cleco Power since 2004, and the fourth IRP report since the issuance of the Commission's IRP General Order. Prior IRP findings and subsequent actions taken by the Company included the following:

- 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 Company's loss of the DEMCO load and a resulting planning reserve margin reduction, the renewable RFP was not issued.
- 2021 IRP Report – Cleco Power issued the "2024 Request for Proposals for Renewable Energy Resources" for 500 MW of renewable energy resources and up to 150 MW of battery storage. The 2024 RFP is still in progress; currently, it is in the proposal evaluation phase. It should be noted that in the Final 2021 IRP Report, Cleco Power identified the

need for up to 500 MW of dispatchable generation, and included the conduct of an RFP for generation in its action plan.

- Cleco Power 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").[6] This project is using the MISO replacement generation process to utilize the existing Dolet Hills Power Station interconnection. The Dolet Hills Solar PPA was ultimately amended and restated, and this amended and restated Dolet Hills Solar PPA was authorized by the Commission pursuant to Order No. U-36502, dated October 8, 2024.
- As noted in the executive summary above, Cleco Power will initiate its next full IRP pursuant to the IRP General Order in October 2025.

Contents of this Interim IRP Report – General Overview

Section 2: Load and Peak Demand

Section 2 provides a discussion of peak demand and load forecast techniques and results. 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.

Section 3: Current Resources

Section 3 provides a description of the Company's existing fleet of EGUs, including a description of each unit's current condition and anticipated remaining service life.

Section 4: Fuel Considerations

Section 4 provides a description of the different fuel types used to fire generation at the Company's EGUs, including procurement and price forecasting.

Section 5: Resource Adequacy; MISO; Regional Transmission Development

Section 5 provides a discussion of resource adequacy and transmission issues affecting Cleco Power's operations. 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 on improving the ability to move electricity across the MISO region reliably and at the lowest possible cost.

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

Section 6: Environmental Considerations

Section 6 provides a discussion of the environmental regulations that affect Cleco Power's operation of the Company's EGUs. 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 Interim IRP considers all existing and relevant proposed regulations.

Section 7: Resource Needs and Other IRP Assumptions

Section 7 provides a discussion of different scenarios, sensitivities, and assumptions that Cleco Power considered in this Interim IRP Report.

Section 8: Results and Modeling

Section 8 provides a discussion of the Interim IRP results and the methodologies and modeling that was utilized to determine the Preferred Portfolio.

Section 9: Preferred Portfolio and Action Plan

Section 9 identifies the Preferred Portfolio resulting from this Interim IRP, and further identifies the Action Plan that Cleco Power would implement to move forward with the Preferred Portfolio.

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 Federal Energy Regulatory Commission ("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	Sales for Resale

Historic Load and Peak Demand

Annual historic load by COS class and for Cleco Power's entire system are presented in Table 2.2, below.

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

Rate Class	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	3,763	3,621	3,472	3,779	3,637	3,598	3,662	3,707	3,791	3,683
GS Energy Only	321	313	301	328	311	287	303	322	331	313
GS Secondary	2,216	2,156	2,125	2,177	2,169	2,055	2,060	2,142	2,160	2,175
GS Primary	1,036	1,030	1,028	1,057	986	952	1,016	1,119	1,126	1,153
Large Power	777	857	930	1,066	956	882	1,025	1,059	999	988
Other Retail	500	487	479	501	460	437	466	470	483	475
Wholesale	3,292	3,139	2,935	3,008	3,066	2,904	2,917	2,956	2,972	825
Total	11,905	11,603	11,270	11,917	11,586	11,115	11,449	11,775	11,862	9,611

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

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

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Peak	2,700	2,490	2,508	2,494	2,492	2,536	2,497	2,533	2,759	2,003
Winter Peak	2,679	2,138	2,404	2,879	2,326	2,121	2,649	2,696	1,967	2,777
Annual Peak	2,700	2,490	2,508	2,879	2,492	2,536	2,649	2,696	2,759	2,777

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 retail service territory has been 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 295,000 customers, of which 252,000 are residential. The customer and energy breakout is shown in Table 2.4, below.

Table 2.4: 2024 Customer Count and MWh Sales

COS Class	# Customers	Sales (MWh)
Residential	251,927	3,683,188
GS Energy Only	27,911	313,130
GS Secondary	8,389	2,174,629
GS Primary	111	1,152,732
Large Power	13	988,106
Other Retail	6,351	474,727
Wholesale	3	824,849
Total	294,705	9,611,360

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 external 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 carried out 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 2015, Cleco Power has added an average of approximately 1,000 new residential consumers per year.

Table 2.5: Residential Class Premise Report

Year	Residential Premises	Growth by Year
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%
2022	249,317	0.4%
2023	251,096	0.7%
2024	251,927	0.3%

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 2015, with a compound annual growth rate of 0.33%. 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 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 forecast 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 at 11.2% since 2001.

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 2024, Residential Lighting, Commercial Lights, and Municipal Lighting accounted for a combined 68,731 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.

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.

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 2.6, below:

Table 2.6: 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 2021. The first year of the previous IRP was 2022. Therefore, forecast versus actual variances can be analyzed for 2022, 2023, and 2024. Table 2.7, 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 2.7: Previous IRP Annual Load Forecast Accuracy

Year	2022	2023	2024
Forecast (GWh)	11,559	11,344	9,575
Weather Effect	73	4	134
Large Power Impact	72	11	0
Other Impacts	(72)	(504)	97
Actual	11,775	11,862	9,611
Forecast Error	1.8%	4.4%	0.4%

The previous forecast for 2022 and 2024 were within approximately two percent of actual load. In 2023, actual energy exceeded the forecast by 4.4%, mainly due to increased wholesale energy sales, which is included in the "Other Impacts" category of Table 2.7.

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 2.8, below:

Table 2.8: Previous IRP Annual Peak Demand Forecast Accuracy

Year	2022	2023	2024
Forecast (MW)	2,573	2,494	1,934
Actual	2,533	2,759	2,003
Forecast Error	(1.6%)	9.6%	3.5%

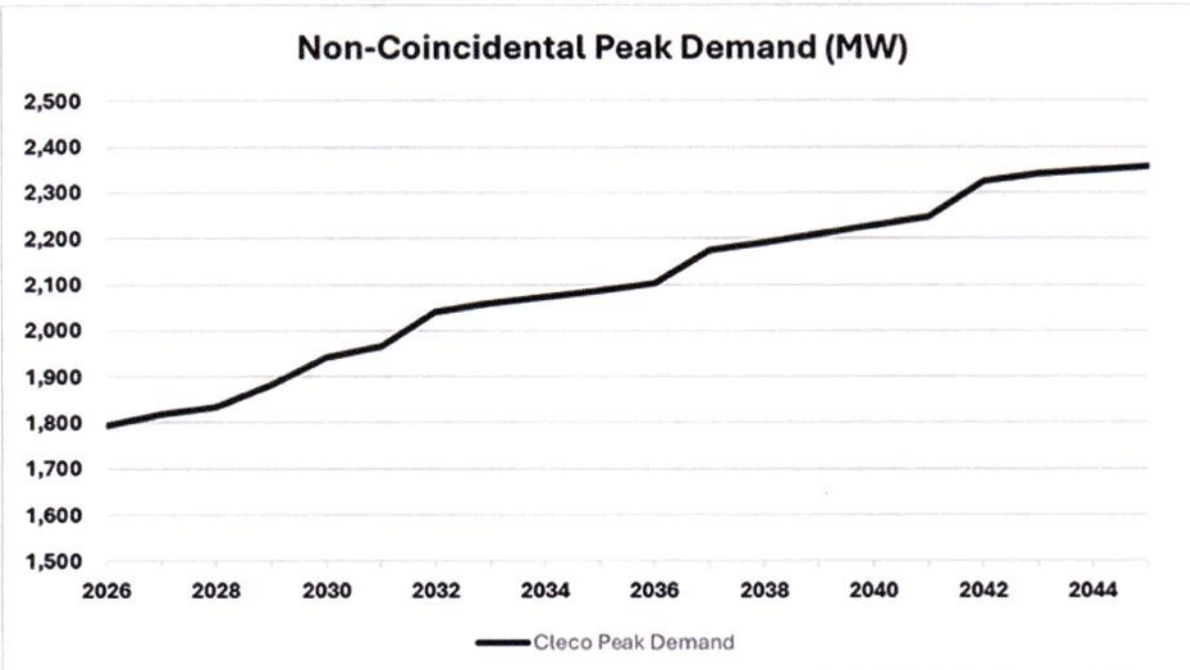
Changes in Methodology from Previous IRP

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



Load forecasts disaggregated by COS class do not extend past 2040. Cleco Power does not forecast peak demand for COS classes; system peaks are reported.

Green Tariff

Cleco Power's green tariff corresponds with the Dolet Hills Solar PPA project, which was authorized by LPSC Order No. U-36502, and will become effective once the solar generating facility that is currently under construction achieves commercial operation. Cleco Power's generation 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.

Section 3: Current Resources

Existing Supply-Side Resources

Electric Generating Units

The Company currently controls a diverse array of resources totaling approximately 2,519 MW of installed capacity to serve customers.[7]

Of the 2,519 MW of the Company's installed capacity, approximately one-third comes from generating resources that have been in service for 43-64 years. Cleco Power assumes that 567 MW of this older generation will be retired over the course of the Interim IRP planning horizon.

The Company's most efficient generation (that is, the Company's CCGT EGUs), which have a weighted average heat rate of [redacted], will be more than 30 years old before new efficient generation is projected to be online (that is, the 700 MW of dispatchable generation identified as part of the Preferred Portfolio).

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	419	
	Rodemacher 2	1982	PRB Coal	149[8]	
	Madison 3	2010	Petcoke/Coal	603	
Acadia Power Station (PB1)	Acadia	2002	Natural Gas	538[9]	
Coughlin Power Station	Coughlin 6	2000	Natural Gas	250	
	Coughlin 7	2000	Natural Gas	480	
Teche Power Station	Teche 4	2011	Natural Gas	34	
St. Mary Clean Energy Center		2019	Waste Heat	47	

[7] Installed capacity based on capacity testing of the generating units and operational tests performed between September 2023 and August 2024. The amounts do not represent generating unit capacity for MISO planning reserve margins.

[8] Cleco Power owns 148 MW (30%), LPPA owns 247 MW (50%), and LEPA owns 99 MW (20%).

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

Detailed descriptions of each EGU are included, below.

Acadia Power Station

Table 3.2: General Resource Information, Acadia Power Station

General Resource Information	
Resource Type	Combined Cycle
Operating Capacity (PB1)	538MW
Fuel Type	Natural Gas
Ownership[10]	Cleco Power 50%, Entergy 50%
Location	Acadia Parish, LA
COD	2002

Acadia Power Station ("Acadia") is a 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 that have been undertaken at Acadia include:

- Acadia CT12 Replace HP, IP, and Bypass CCI Valves in 2022;
- Acadia Common AC10 – Controls Upgrade on AVR in 2022;
- Acadia CT and ST Major Inspection in 2022;
- Acadia SCR Catalyst Replacement in 2023; and
- Acadia ST13 Replace LP Compensator in 2024.

[10] 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	730MW
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 Unit 6 was recommissioned in 2000 with new current transformers ("CTs") and heat recovery steam generator ("HRSG"), although its steam turbine ("ST") was originally commissioned in 1961 and has been in service for 64 years. Only three percent of STs comparable to Coughlin Unit 6 remain in service. The ST for Coughlin Unit 7 was originally commissioned in 1964 and has been in service for 60 years. Only nine percent of STs comparable to Coughlin Unit 7 remain in service.

Major maintenance projects that have been undertaken at Coughlin include:

- Unit 6 Upgrade ST EHC Filter Skid in 2022;
- Unit 6 CT61-Inst Ammonia Skid Detection in 2022;
- Unit 7 Replace Res Aux Transform RAT in 2022;
- Common Plant -ABB Evolution in 2022;
- Unit 7 ST EHC Conversion in 2023; and
- Unit 7 ST IP Feedwater Pumps Replacement in 2024.

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 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 entered commercial operation in 1982. 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. However, the unit is subject to the U.S. Environmental Protection Agency's ("EPA") CCR and ELG rules and must cease coal-fired operations by 2028. Rodemacher 2 has been operating for 43 years, and only 25% of comparable generating units remain online past 41 years of operations. The unit has already surpassed its designed operating hours by approximately 33%. Although Rodemacher 2 has generally been a reliable unit throughout its operational years, its output began to decline in 2024, and it has been underperforming since. As part of the Action Plan described in Section 9, below, Cleco Power plans to convert Rodemacher 2 from coal-firing to natural gas-firing to fire generation.

Major maintenance projects that have been undertaken at Rodemacher 2 include:

- Replace Baghouse Elevator in 2022;
- Air heater & sootblower upgrade in 2022;
- Baghouse Bag & Cage Replace in 2023;
- Final Drive Rebuild in 2023; and
- 2-2 Booster Fan 2-2 Booster Fan in 2024.

Madison Unit 3

Table 3.5: General Resource Information, Madison Unit 3

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	603MW
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. As described in Section 9, as part of Cleco Power's Preferred Portfolio and Action Plan, Cleco Power is currently assessing the potential to co-fire natural gas in Madison 3, which would allow for greater fuel flexibility and enable the unit to remain online beyond December 31, 2031, in accordance with Clean Air Act 111(d) BSER requirements.[11]

Major maintenance projects that have been undertaken at Madison 3 include:

- Limestone Silo Upgrades in 2022;
- Rebuild U3 Loopseal Blower in 2023;
- Air Heater Basket Replacement in 2023;
- PLC Processor Upgrade in 2024; and
- TDBFP Recirc Valve Replacement in 2024.

[11] *See* Standards of Performance 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 Electric Generating Units; Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (to be codified at 40 C.F.R. pt. 60).

Nesbitt Unit 1

Table 3.6: General Resource Information, Nesbitt Unit 1

General Resource Information	
Resource Type	Steam Turbine
Operating Capacity	419MW
Fuel Type	Natural Gas
Ownership	Cleco Power 100%
Location	Rapides Parish, LA
COD	1975

Nesbitt Unit 1 ("Nesbitt 1" or "NPS1") is a natural-gas-fired EGU at Brame. Nesbitt 1 began operations in 1975. 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. Nesbitt 1 has been operational for 50 years. Approximately 50% of generating units comparable to Nesbitt 1 remain operational beyond 55 years, and 25% remain in service beyond 63 years. Nesbitt 1 is projected to retire in 2035 when it reaches 60 years of operational age.

Major maintenance projects that have been undertaken at Nesbitt 1 include:

- Rebuild 1-2 LPSW Pump in 2022;
- Rebuild 1-1 & 1-3 Condensate Pumps in 2023;
- Boiler Waterwall Panel Replacement in 2024; and
- Replace 1-2 FD Fan Motor in 2025.

Teche Unit 4

Table 3.7: 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 3.8: 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.

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 2024, natural-gas-fired generation provided 73% of electricity produced by utilities and independent power producers in Louisiana. The next most used fuel types were nuclear and coal at 17% and 8% of state generation, respectively.[12]

Cleco Power procures most of its natural gas supply 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. Cleco Power has contracted with Pine Prairie Energy Center for 2,000,000 MMBtus of natural gas storage through March 2030.

Cleco Power utilizes a long-term natural gas hedging program to mitigate the impact of fuel price volatility on customer rates. This program is well-defined and includes forecasts of Cleco Power's natural gas requirements over several years.

Cleco Power relied on a fuel price forecast from RBAC Inc. to develop its natural gas forward curves. RBAC Inc. develops and licenses economic forecasting tools designed for management decision support systems for the energy industry, as well as for state and federal government agencies involved in energy, transportation, and environmental sectors. The company's principal products focus on the industry-standard GPCM Natural Gas Market Forecasting System, which includes the GPCM Base Case Database for North America and GPCM Viewpoints on Natural Gas.

High and low gas price sensitivities are projected to average 20% higher and 36% lower, respectively, compared to the base projection over the IRP term.

Solid Fuel Considerations

Price projections for Cleco Power's solid fuels are based on proprietary projections of Power River Basin ("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.

[12] *See* https://www.eia.gov/state/analysis.php?sid=LA.

PRB Coal

Cleco Power uses PRB coal to generate electricity at Rodemacher 2. Cleco Power enters into contracts for PRB coal for periods of six months to twelve months. Cleco Power also contracts with Wells Fargo Rail Corporation for the use of approximately 113 railcars to transport the coal from the PRB region to Rodemacher 2. For the period from January 2025 – December 2025, Cleco Power purchased approximately 1,076,000 tons of PBR coal, with 464,000 tons representing Cleco Power's share.

Petcoke and Illinois Basin Coal

Madison 3 is fueled by petcoke and Illinois Basin 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 Illinois Base 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. For 2024, Cleco Power has contracted for 350,000 tons of petcoke and 150,000 tons of Illinois Basin coal. Cleco Power has not yet executed any contracts for petcoke or Illinois Basin coal for 2025. Louisiana waterways, including the Mississippi River and the Red River, are used to deliver both Illinois Basin coal and petcoke to Madison 3. Figure 4.1, 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.

Figure 4.1: PRB and Petcoke/Illinois Coal Prices

[redacted]

Section 5: Resource Adequacy; MISO; Regional Transmission Development

Introduction

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

MISO has historically viewed resource adequacy 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 resource adequacy when assessing generation and transmission siting and when setting retail electric rates. Resource adequacy 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 resource adequacy. 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.

Minimum Capacity Obligation

In LPSC Docket No. R-36263, on June 6, 2024, the Commission approved of a minimum physical capacity requirement. To ensure continued resource adequacy and reliability in Louisiana, the policy of the Commission mandates that all Louisiana electric utilities in MISO engage in long-term resource planning. The objective is for these utilities to own or procure an amount of Qualified Capacity Resources equal to their applicable Planning Reserve Margin Requirement ("PRMR") for each MISO planning year. This rule requires an advanced demonstration of capacity procurement plans that are based on Qualified Capacity Resources. Although the rule requires a demonstration for acquiring or procuring up to 90% of the utility's PRMR, its purpose is for every utility to prudently plan to supply 100% of its PRMR with Qualified Capacity Resources.

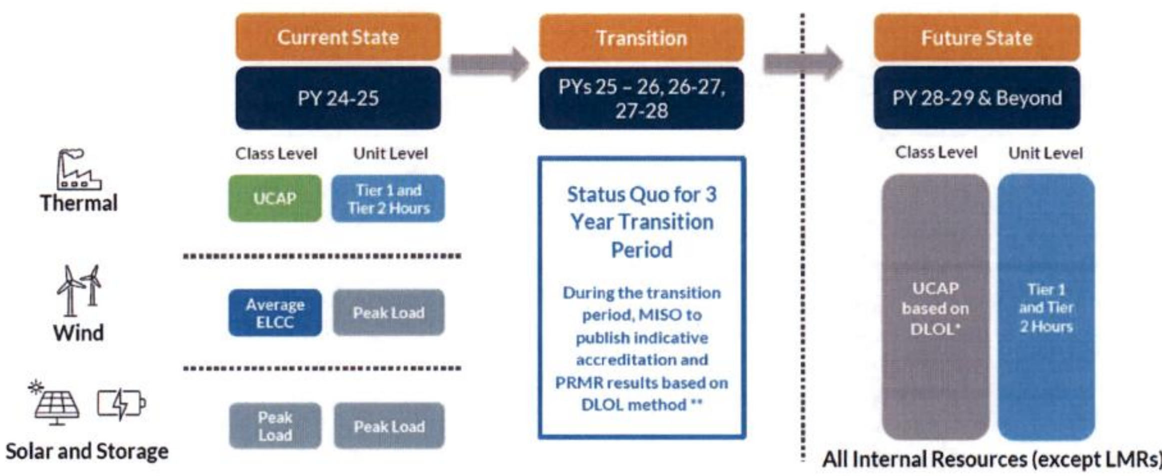
Evolving MISO Capacity Accreditation Methodology

In June 2023, MISO transitioned from an annual to a seasonal resource adequacy construct. The Seasonal Accredited Capacity ("SAC") construct assigns different values to resources during the four seasons of the planning year: summer, fall, winter, and spring. This shift, effective with the 2023/2024 MISO planning year, recognizes the increasing variability of reliability challenges the grid faces throughout the year. These challenges arise from factors such as baseload generation retirements, higher penetration of intermittent resources, extreme weather events, and declining excess reserve margins. The Interim IRP has incorporated the foundational elements of MISO's change from annual to seasonal resource adequacy into its modeling, enabling more precise planning and resource selection based on the specific needs and resource availability of each season.

In addition to transitioning to a seasonal resource adequacy construct, MISO submitted a new probabilistic capacity accreditation framework to the FERC, in February 2024. This new Direct Loss-of-Load ("DLOL") modeling framework was approved by the FERC in October 2024 and is set to take effect in the 2028/2029 MISO planning year.

MISO established a three-year transition period to provide market participants with the opportunity to better understand and plan for the accreditation and reserve margin calculations based on the DLOL framework, as shown in Figure 5.1 below.

Figure 5.1: Three-Year Transition from Current State to SAC to DLOL



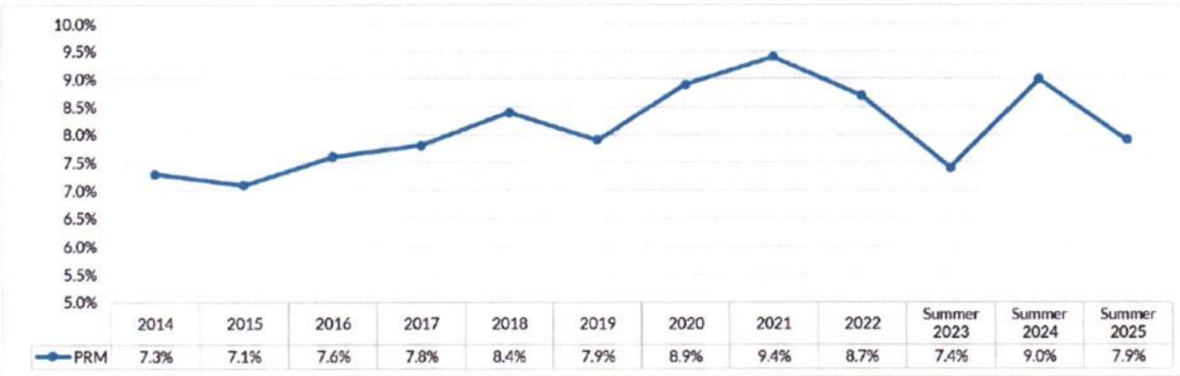
MISO Resource Adequacy

As an LSE in MISO since 2013, Cleco Power is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. Cleco Power must adhere to resource adequacy requirements and long-term planning reserve margin targets. Resource adequacy ensures there is enough available power to serve peak demand. MISO acts as an intermediary between energy sellers and buyers in its region through the annual Planning Reserve Auction ("PRA").

Planning Reserve Margin

In compliance with Module E-1 of the MISO Tariff, MISO conducts its annual Loss of Load Expectation ("LOLE") study to determine the system Planning Reserve Margin Unforced Capacity ("PRM UCAP") and the Local Reliability Requirement ("LRR") for each Local Resource Zone ("LRZ") for each season of MISO planning year 2025/2026. The actual effective PRMR for each season of the 2025/2026 PRA will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1 of each year. Figure **5.2** below shows the MISO historical planning reserve margin percentages over the last 10 years. The last three values (Summer 2023, 2024, and 2025) represent the planning reserve margins since MISO implemented its seasonal construct.

Figure 5.2: Planning Reserve Margin Targets Across 10 Years



<u>**Planning Reserve Margin under MISO's Seasonal Construct**</u>

Beginning with the 2023/2024 planning year, MISO implemented a Seasonal Accredited Capacity ("SAC") construct for resource adequacy. SAC establishes parameters on a four-season basis for both accreditation and the determination of the PRMR. SAC accredits thermal resources seasonally based on their performance during a minimum target of 65 higher-risk hours in each season, rather than the historical annual equivalent forced outage rate ("EFOR") unforced capacity value ("UCAP") approach. MISO defines "Tier 2" resource adequacy hours as the highest risk hours, which include declared Maximum Generation Emergency hours plus a percentage of other defined "tight margin" hours. Thermal resource accreditation is weighted toward resource performance during these hours. "Tier 1" hours include all hours that are not defined as "Tier 2." This approach rewards resources that perform well during critical "Tier 2" hours and penalizes those that do not. The accreditation of other resource types, including renewable energy resources, is also now conducted on a seasonal basis.

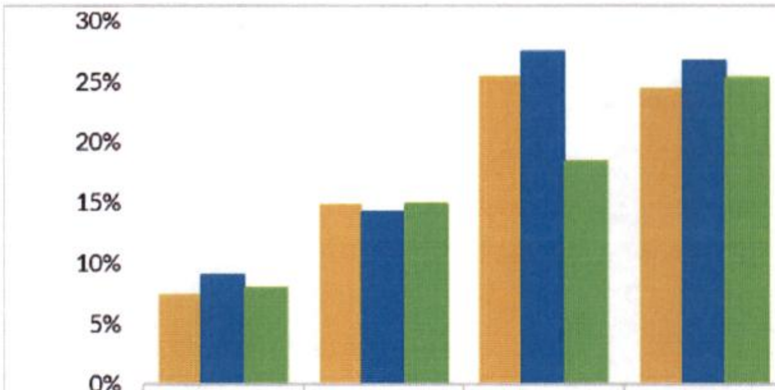
Another component of the SAC construct is the introduction of the "31-Day Rule" for planned outages within a season. This rule stipulates that if capacity cleared in the auction for a season is in planned outage for more than 31 days during that season, it must be replaced with uncleared capacity. Alternatively, instead of physical replacement, the generator can choose to pay a fee known as the capacity replacement non-compliance charge. If applicable, generators are allowed to incorporate this charge into their capacity offers to account for the future cost of these outages in the capacity auction. The Company strives to manage its planned outage schedule to minimize the occurrence of outages exceeding 31 days. Consequently, the 31-Day Rule is not modeled in this Interim IRP Report.

Figure 5.3 shows the initial target reserve margins, prior to the burden of adding MISO's Reliability Based Demand Curve ("RBDC"),[13] for the three seasons under the seasonal construct. Although the summer PRM appears reasonable, it is based on actual SAC accreditation for each

[13] Reserve margins with MISO's RBDC burden is provided in Figure 5.5: Target Planning Reserve Margins vs Actual Cleared Planning Reserve Margins

generating resource, rather than the installed or actual tested capacity deliverable by the generating resource. The limited historical information highlights the inherent uncertainty in MISO's seasonal construct.

Figure 5.3: Seasonal Planning Reserve Margins Since MISO Began its Seasonal Construct



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

<u>Uncertainty Under Seasonal Construct</u>

As previously mentioned, SAC now accredits thermal resources on a seasonal basis, evaluating their performance during a minimum target of 65 higher-risk hours in each season, rather than using the historical annual equivalent forced outage rate ("EFOR") unforced capacity value ("UCAP"). Therefore, the capacity allocation for generation can vary significantly, shifting by hundreds of MW from season to season and year to year.

MISO publishes the initial set of the 65 higher-risk hours each season six months after has concluded. As a result, generator owners are unable to effectively estimate the amount of capacity they will have available for the next PRA or determine the additional capacity they may need to acquire until six months after each season. Furthermore, this estimation is based on draft information that is subject to change by MISO.

MISO publishes an initial seasonal capacity accreditation value in mid-December each year. However, the final corrected file is not released until mid-February and must be confirmed by each market participant by March 25th at the latest. This, coupled with the limited number of uncontracted resources in LRZ 9 and the reduction in capacity offered into the MISO PRA, requires load-serving entities to plan for uncertainty in each season.

<u>Planning Resource Auction</u>

The annual PRA is MISO's process for demonstrating sufficient resources and enabling market participants to sell capacity to other market participants through an auction. MISO establishes the capacity requirements for each season, spanning from June 1 to May 31 of the following year.

A key limitation of the PRA is that it will establish an auction price even when the available capacity is insufficient to meet the forecasted peak demand.

MISO determines the region's energy needs, including a PRM, based on multiple studies, including demand forecasts from its members. The reserve margin is calculated using MISO's annual Loss of Load Expectation Study. Auction offers are accepted during the last four business days of March each year, after which MISO applies transmission constraints and publishes the auction results in April of each year.

Reliability Based Demand Curve ("RBDC") – In June 2024, FERC approved MISO's implementation of the RBDC. MISO states that the curve will accurately value and provide the appropriate price signals to encourage resource investment and retirement decisions within the system. These signals and pricing improvements, on both a seasonal and locational basis, are designed to consistently support reliability needs. MISO planning year 25/26 was the first year of RBDC implementation. The MISO PRA results for MISO planning year 24/25 and MISO planning year 25/26 are provided below. Notably, MISO planning year 25/26 had a substantial increase in pricing across the board, consistent with MISO's statement that the RBDC improves price signals, thereby reflecting the increased value of accredited capacity beyond the seasonal PRM target.[14]

Ultimately, the RBDC process increases the uncertainty for LSEs in MISO. MISO only provides LSEs with an estimate of the amount of capacity[15] that the LSE must process, or must acquire in the PRA if the LSE does not have sufficient capacity. As part of the PRA, the initial PRMR may change based on inputs during the conduct of the auction that are unknown to LSEs prior to the conduct of the auction. The result is after the PRA, the LSE's capacity requirement is different than it was prior to the PRA. Therefore, an LSE could have sufficient capacity before the PRA, and then find out that it does not have sufficient capacity after the PRA.

[14] Planning Resource Auction Results for Planning Year 2025-26 presentation dated April 2025, downloaded from https://www.misoenergy.org/events/2025/pra-results-review---april-29-2025/.

[15] Initial PRMR is the capacity requirement provided to LSEs by MISO prior to each PRA.

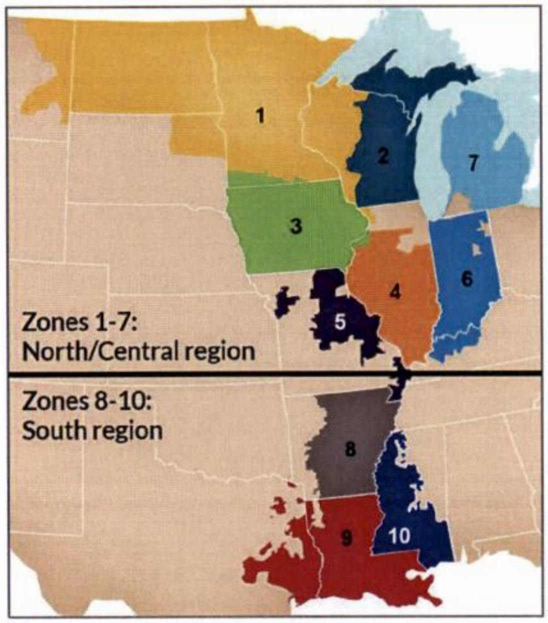
Figure 5.4: 2024 PRA Results

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall	Winter	Spring
		(Price $/MW-Day)			
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

MISO Resource Adequacy Zones

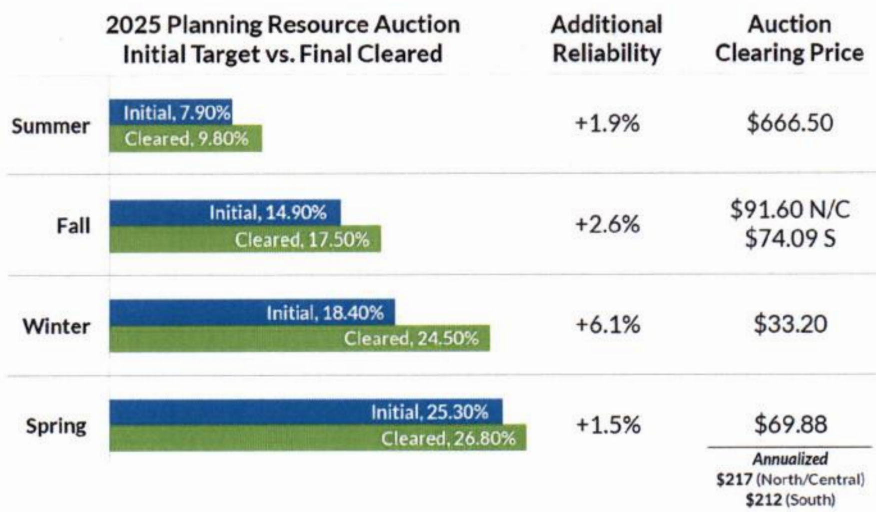


In MISO planning year 25/26, the final reserve margins cleared using the RBDC range from 1.9% in the summer to 6.1% in the winter season, as shown in Figure 5.5. This increases the number of resources required to offer energy into MISO daily and raises the auction clearing price.

Figure 5.5: Target Planning Reserve Margins vs Actual Cleared Planning Reserve Margins

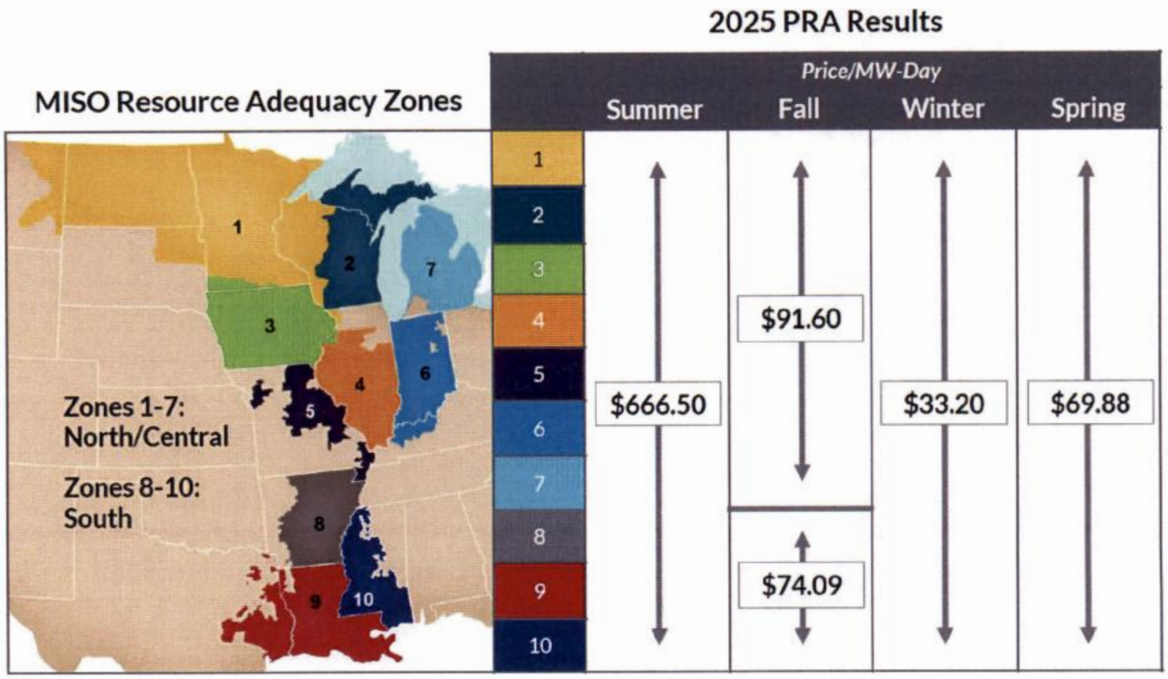
MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices



PD.50556714.11

Figure 5.6: 2025 PRA Results



In addition to the implementation of the RBDC, there was an overall decrease in capacity resources within MISO.[16] Specifically, MISO experienced a 2.1% reduction in capacity offered for the summer season, decreasing from 140.7 GW in MISO planning year 24/25 to 137.8 GW in MISO planning year 25/26, as shown in **Figure 5.7**. MISO South experienced a similar reduction of 1%, as shown in **Figure 5.8**.

[16] *See* PowerPoint Presentation.

Figure 5.7: Capacity offers in Summer PY 24/25 vs PY 25/26

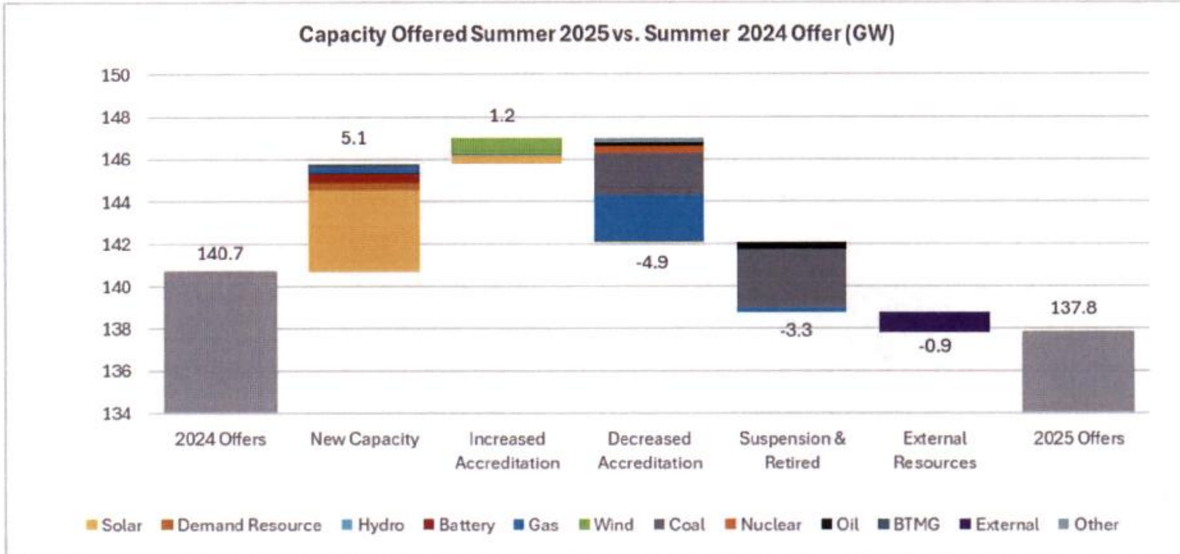
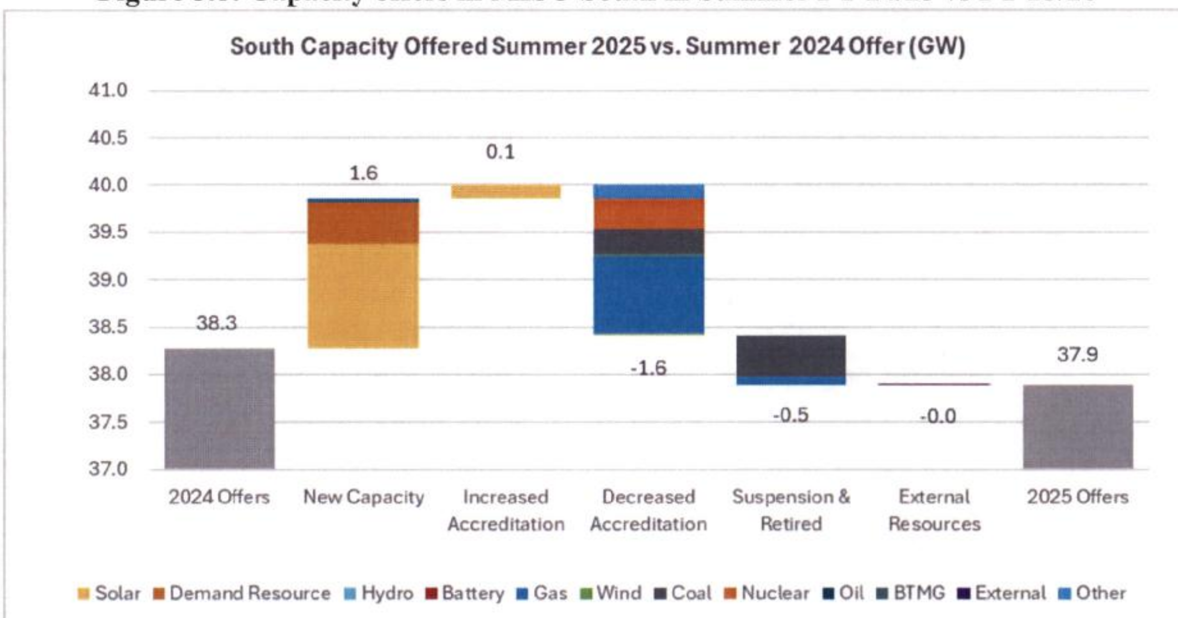


Figure 5.8: Capacity offers in MISO South in Summer PY 24/25 vs PY 25/26



Direct Loss of Load

As part of the ongoing evolution of the SAC methodology, MISO has filed with the FERC for approval to implement an Effective Load Carrying Capability ("ELCC")-based approach for resource adequacy, known as Direct Loss of Load ("DLOL"), starting with the 2028/2029 planning year. DLOL is a two-step process where the expected marginal contribution to reliability is determined for each resource class. This class-level accreditation is then allocated to individual resources within the class based on recent history, using the SAC "Tier 2" hours methodology. This process can be summarized as first determining the "size of the pie" (total accreditation of the resource class) and then dividing it among individual resources within the class. The DLOL approach includes separate classes for coal units, natural gas units, solar, wind, hydro, energy storage, and others.

This process will produce seasonal class averages for the various resource types. It is anticipated that these class averages may evolve over time as the total ICAP of each resource class changes relative to the overall MISO system. MISO has provided indicative class performance, showing the current UCAP to ICAP ratio under the SAC construct and the proposed DLOL to ICAP ratio, based on MISO planning year 2023/2024 data. The initial values presented by MISO for MISO planning year 23/24 are shown in **Table 5.1** below,[17] while the current MISO planning year 25/26 values are provided in **Table 5.2**.[18] The results indicate that the values remain uncertain and are generally lower in the Fall and Winter seasons, even though peak demand during those seasons can rival or exceed that of the Summer season.

Table 5.1: MISO Proposed Accreditation by Resource Class PY 23/24

	Summer		Fall		Winter		Spring	
Resource Class	SAC[1]	DLOL	SAC	DLOL	SAC	DLOL	SAC	DLOL
Gas excl. CC[2]	90%	88%	84%	88%	79%	66%	84%	69%
Combined Cycle	91%	90%	94%	89%	90%	74%	92%	75%
Coal	92%	91%	91%	88%	90%	73%	89%	74%
Hydro	96%	96%	94%	96%	93%	92%	97%	88%
Nuclear	95%	90%	96%	85%	95%	86%	92%	80%
Pumped Storage	99%	98%	91%	98%	94%	50%	89%	67%
Storage	95%	94%	95%	93%	95%	91%	95%	95%
Solar	45%	36%	25%	31%	6%	2%	15%	18%
Wind	18%	11%	23%	15%	40%	16%	23%	16%
Run of River	100%	100%	100%	100%	100%	100%	100%	100%

Note 1: Current values under the SAC construct represent UCAP for thermal resource class and average ELCC starting values for solar and wind resource classes.

Note 2: MISO has adjusted the gas resource class by removing combined cycle resources.

[17] Source: MISO Market Redefinition: Accreditation Reform; February 28, 2024, RASC

[18] Sources: MISO Letterhead Template; Microsoft Word - Indicative DLOL Results PY 2025-2026_Update_Apr2025

Table 5.2: MISO Current SAC and Proposed DLOL Accreditation by Resource Class PY 25/26[19]

	Summer		Fall		Winter		Spring	
Resource Class	SAC	DLOL	SAC	DLOL	SAC	DLOL	SAC	DLOL
Biomass		52%		47%		51%		49%
Coal		89%		85%		76%		72%
Dual Fuel Oil/Gas		87%		84%		79%		77%
Fossil Steam 0-400MW	85%		79%		77%		76%	
Fossil Steam 400-1000MW	85%		78%		77%		75%	
Gas		88%		85%		64%		68%
Combustion Turbine 0-50MW	90%		85%		74%		85%	
Combustion Turbine 50+MW	93%		87%		69%		85%	
Diesel	93%		89%		88%		90%	
Combined Cycle	94%	95%	85%	92%	85%	77%	85%	78%
Nuclear		94%		91%		90%		81%
Oil		77%		75%		74%		73%
Pumped Storage		98%		93%		77%		66%
Reservoir Hydro		89%		82%		76%		70%
Run-of-River Hydro		62%		52%		58%		63%
Solar		45%		28%		19%		28%
Wind		8%		15%		23%		15%
Storage		61%		88%		85%		90%

Increase in Emergency Events in MISO

Cleco Power experienced a significant increase in emergency events from 2024 to 2025, with an 81% rise primarily driven by severe weather and conservative operations, as shown in **Table 5.3**. Meanwhile, the MISO South footprint saw the most dramatic escalation, with a 133% increase in events, largely due to a surge in capacity advisories and severe weather declarations concentrated in the mid-year months. The tenfold increase in capacity advisories indicates that the system is frequently operating near its limits, especially during peak demand periods in the summer. This suggests that reserve margins are tightening, and the grid is under increasing pressure to meet load requirements. In contrast, the MISO North and Central regions remained relatively stable in total event count, but exhibited clear sensitivity during summer peaks, particularly in capacity advisories. Overall, this analysis underscores growing operational stress across the MISO footprint, with weather-related disruptions and peak demand periods emerging as key drivers of system strain.

[19] MISO did not provide a single comprehensive table. This table was derived using MISO's Planning Year 2025-2026 Final Schedule 53 Class Averages, and Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results, available at misoenergy.com

Table 5.3: Emergency Events Affecting Cleco Power and MISO South

Cleco Power as Affected Entity 2024												
Declaration Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Capacity Advisory					1			2	1			
Cold Weather												
Conservative Operations					3		6	2	1			2
Hot Weather								3				
Max Gen												
Restoration Event							1					
Severe Weather			1	1	3		2		1			2
Transmission Advisory												
Total			1	1	7		9	7	3			4

2025							
Declaration Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Capacity Advisory					1	3	6
Cold Weather	5	1					
Conservative Operations	3	4			2	5	3
Hot Weather							2
Max Gen							3
Restoration Event							
Severe Weather	1		5	7	4	1	1
Transmission Advisory							1
Total	9	5	5	7	7	9	16

MISO South as Affected Entity 2024												
Declaration Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Conservative Operations					**3**		**6**	**2**	**1**	**3**		**2**
Severe Weather			**1**	**1**	**7**		**2**		**1**			**2**
Capacity Advisory					**1**			**2**	**1**			
Hot Weather								**3**				
Restoration Event							**1**					
Total			**1**	**1**	**11**		**9**	**7**	**3**	**3**		**4**

2025							
Declaration Type	Jan	Feb	Mar	Apr	May	Jun	Jul
Capacity Advisory					**1**	**8**	**20**
Severe Weather	**1**		**5**	**7**	**5**	**2**	**1**
Transmission Advisory							**1**
Max Gen							**3**
Conservative Operations	**5**	**4**			**2**	**5**	**3**
Hot Weather							**2**
Cold Weather	**5**	**1**					
Total	**11**	**5**	**5**	**7**	**8**	**15**	**30**

Regional Transmission Development

Cleco Power serves approximately 295,000 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 12,300 miles of distribution lines operating at less than 69 kV to serve its retail and wholesale customers within Louisiana. Cleco Power also owns approximately 1,387 miles of transmission lines comprised of:

- 29 miles of 69 kV line;
- 682 miles of 138 kV line;

- 609 miles of 230 kV line; and
- 67 miles of 500 kV line.

Customers are served through 85 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.

<u>The Bulk Electric Grid</u>

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 load balancing area ("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.

<u>MISO Transmission Projects – Cleco Power</u>

As a Transmission Owner in MISO, Cleco Power participates annually in MISO's MTEP process. MISO's annual MTEP process involves a top-down review of all transmission needs within MISO's footprint. Currently, Cleco Power conducts its annual NERC TPL assessment, which projects system needs over the next 10 years to support load growth and reliability within the Cleco Power footprint. This assessment represents the bottom-up portion of the MISO process. Any deficiencies identified by Cleco Power are analyzed internally to determine the most cost-effective solutions that enhance transmission system reliability. These solutions are then submitted to MISO as part of its annual MTEP process. MISO reviews these submitted projects as part of its top-down review. If MISO agrees that a proposed project is the best alternative to address the identified issue, it approves the project in December of each year.

Projects proposed in MISO's MTEP process are part of a ongoing effort to strengthen the existing transmission network. A list of approved Cleco Power projects can be found in Appendix A of MISO's MTEP 16 through MTEP 21 cycles, detailed in Appendix F – Table 22 through Table 27, respectively. Additionally, submitted Target Appendix A projects for MTEP 22 and MTEP 25 are listed in Appendix F – Table 28 and Table 29. These future transmission projects, along with other transmission plans developed over the next three years, will be important inputs in considering future resource needs.

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 of Directors 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 2026 and tentatively receiving MISO Board's approval in December 2026.

Cleco Power is closely monitoring the MISO LRTP process with 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.

Other significant environmental rules are applicable, were covered in the reference IRP, and will be comprehensively addressed in the October 2025 IRP. The rules requiring Cleco Power to cease coal-fired operations at Madison 3 and Rodemacher 2 include Clean Air Act Section 111 BSER (b) and (d), Effluent Limitation Guidelines ("ELG"), and Coal Combustion Residuals ("CCR").

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.

On May 11, 2023, the EPA issued a proposed rule under the Clean Air Act ("CAA") 111 aimed at reducing CO_2 emissions from fossil-fuel-fired EGUs, and the rule was finalized on May 9, 2024. The regulation is titled "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 Electric Generating Units; and Repeal of the Affordable Clean Energy Rule." The final rule addresses CO_2 emissions from new and reconstructed fossil fuel-fired turbines, modified coal-fired boilers, and existing coal-fired boilers.

For existing steam generating units (*e.g.*, coal-fired, natural gas-fired, and oil-fired), the final rule requires states with affected units to implement the existing source emission guidelines from this rule in a State Implementation Plan ("SIP"). The SIP must establish performance standards for existing affected units that are at least as stringent as the emission guidelines included in the final Clean Air Act 111d rule by the EPA. However, states may consider Remaining Useful Life and Other Factors ("RULOF"), as outlined in the Clean Air Act 111d regulations, when establishing a standard for a particular source. This consideration could result in a less stringent standard or a longer compliance schedule. The RULOF provision is applicable only when there are significant differences between a generation unit's circumstances and the information the EPA used to determine the applicable emissions limitation or compliance schedule, making it unreasonable for the affected unit to achieve the required reduction by the compliance date. States must submit their SIPs to the EPA within two years of the final rule's effective date, which is July 8, 2024.

For existing coal-fired units, such as Rodemacher 2 and Madison 3 at Brame, the regulation categorizes them into long-term and medium-term subcategories. Long-term coal-fired steam generating units are those that do not intend to permanently cease operations before January 1,

2039. For these units, Best System of Emission Reduction ("BSER") is Carbon Capture and Storage ("CCS") with a 90% capture rate of CO_2 emissions.

In addition to the emission guidelines for existing long-term coal-fired units, the emission standards for new baseload turbines at Phase 2 rely on CCS. According to the preamble of the regulation, the EPA determined that CCS is the BSER based on technological advances from full-scale deployment and supportive state and federal policies, which serve as evidence that CCS can be deployed at scale today. It is also noted that the cost of CCS has decreased in recent years due to process improvements, technological advancements, and increased funding both from the Inflation Reduction Act ("IRA") Section 45Q and the Infrastructure Investment and Jobs Act ("IIJA"). Furthermore, the EPA cites state clean energy goals and CCS adoption requirements as additional evidence that CCS has been adequately demonstrated.

However, CCS is not currently an affordable or reliable option for nationwide use. In the rule's preamble text, the EPA stretches the statutory phrase "has been adequately demonstrated" to assert that CCS, a technology that the EPA acknowledges requires eight years of "lead time" to implement, is the BSER for new and existing long-term sources. Furthermore, the EPA's assertion that CCS technology is already "adequately demonstrated" and capable of achieving a 90% capture of carbon emissions is not supported by the rule's underlying administrative record. Additionally, it is important to note that there are no combined cycle turbine facilities utilizing CCS due to economic and technical challenges. As a result, the technology has not been demonstrated in practice for combined cycle gas turbine facilities or any commercial-scale power-generating facility.

For medium-term coal-fired steam generating units, which are defined as those that have elected to commit to permanently cease operations after December 31, 2031, and before January 1, 2039, the BSER is 40% natural gas co-firing by heat input. It is noted that that this control technology has been operated at scale and is widely applicable to various sources. For this subcategory, the EPA determined that there is insufficient time to amortize the capital costs of CCS, leading to higher annualized costs. The presumptively approvable performance standard is a 16% reduction in the annual emission rate (lb CO_2 per MWh-gross) from the unit-specific baseline, with a compliance deadline set for January 1, 2030.

For existing coal-fired generating units that plan to permanently cease operations before January 1, 2032, there are no emission guidelines. This exclusion is based on the determination that units retiring before this date generally do not have cost-effective options for improving greenhouse gas ("GHG") emissions performance.

Table 6.1: Carbon emission standards for existing fossil-fuel fired steam generators

Unit type	BSER	Emission Limit
Coal-fired -long term	CCS	90% capture of CO2 (88.4% reduction in lb/mwh CO2 emission rate by January 1, 2032.
Coal-fired -medium term	Co-firing 40% (by heat input) natural gas	16% reduction in lb CO2/MWh emission rate by January 1, 2030
Coal-fired – cessation of operation by January 1, 2032	Exempt from rule	Exempt from rule
Natural gas/oil-fired -base load	Routine methods of operation/maintenance	1,400 lb CO2/MWh by January 1, 2030.
Natural gas/oil-fired – intermediate load	Routine methods of operation/maintenance	1,600 lb CO2/MWh by January 1, 2030.
Natural gas- fired/-low load	Uniform low-emitting fuels	130 lb CO2/MMBtu by January 1, 2030.
Oil-fired-low load	Uniform low-emitting fuels	170 lb CO2/MMBtu by January 1, 2030.

Table 6.2 provides the current Clean Air Act 111 BSER standards. On June 11, 2025, the EPA proposed a repeal of GHG emissions standards for fossil fuel-fired generating units. However, as of the filing of this report, Clean Air Act 111 BSER remains effective.

In this action, the U.S. EPA is proposing to repeal all GHG emissions standards for fossil fuel-fired power plants. The EPA asserts that the CAA requires it to determine whether GHG emissions from these plants contribute significantly to dangerous air pollution as a prerequisite for regulation. The EPA is proposing to find that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. Alternatively, the EPA is proposing to repeal a narrower set of requirements, including the emission guidelines for existing fossil fuel-fired steam generating units, the CCS-based standards for coal-fired steam generating units undergoing large modifications, and the CCS-based standards for new baseload stationary combustion turbines.[20]

[20] *See* https://www.federalregister.gov/documents/2025/06/17/2025-10991/repeal-of-greenhouse-gas-emissions-standards-for-fossil-fuel-fired-electric-generating-units.

Table 6.2: 111 BSER Standards[21]

<table>
<tr><th colspan="4">FINAL CARBON POLLUTION STANDRADS FOR NEW AND EXISTING FOSSIL-FUEL FIRED ELEECTRICITY GENERATORS</th></tr>
<tr><th colspan="2">Existing 111(d) Steam Generators</th><th colspan="2">New Source and Reconstructed 111(b) Stationary Combustion Turbines</th></tr>
<tr><th>Coal-Fired Boilers</th><th>Natural Gas and Oil-Fired Boilers</th><th>Phase I
Date of promulgation or initial startup</th><th>Phase II
Beginning in Jan 1, 2032</th></tr>
<tr><td rowspan="2">Long-term subcategory: For units operating on or after January 1, 2039

BSER: CCS with 90 percent capture of CO_2 (88.4% reduction in emission rate lb/MWh-gross) by January 1, 2032</td><td rowspan="6">BSER: routine methods of operation and maintenance with associated degree of emission limitation:

Base load unit standard:
(annual capacity factors greater than 45%) 1,400 lb CO_2/MWh-gross

Intermediate load unit standard:
(annual capacity factors greater than 8% and less than or equal to 45%) 1,600 lb CO_2/MWh-gross.

Low load units:
(annual capacity factors less than 8%) a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

Compliance date of January 1, 2030</td><td colspan="2">Low Load Subcategory (Capacity Factor <20%)</td></tr>
<tr><td><u>BSER</u>: Use of lower emitting fuels (e.g., hydrogen, natural gas and distillate oil)
<u>Standard</u>: less than 160 lb CO_2/MMBtu</td><td>EPA is not finalizing a Phase II BSER for low load units</td></tr>
<tr><td rowspan="2">Medium-term subcategory: For units operating on or after Jan. 1, 2032, and demonstrating that they plan to permanently cease operating before January 1, 2039

BSER: co-firing 40% (by heat input) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis) by January 1, 2030</td><td colspan="2">Intermediate Load Subcategory (Capacity Factor 20% to 40%*)
*Source-specific upper bound threshold based on EGU design efficiency</td></tr>
<tr><td><u>BSER</u>: Highly efficient simple cycle technology with best operating and maintenance practices
<u>Standard</u>: 1,170 lb CO_2/MWh-gross</td><td>EPA is not finalizing a Phase II BSER for intermediate load units</td></tr>
<tr><td rowspan="2">For units demonstrating that they plan to permanently cease operating before January 1, 2032

Units are exempt from the rule. Cease operations dates finalized in state plans for exemption purposes are federally enforceable.</td><td colspan="2">Base Load Subcategory (Capacity Factor >40%*)
*Operation above upper-bound threshold for Intermediate Subcategory</td></tr>
<tr><td><u>BSER</u>: Highly efficient combined cycle generation with the best operating and maintenance practices
<u>Standard</u>: 800 lb CO_2/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more)
<u>Standard</u>: 800 to 900 lb CO_2/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)</td><td><u>BSER</u>: Continued highly efficient combined cycle generation with 90% CCS by Jan 1, 2032
<u>Standard</u>: 100 lb CO_2/MWh-gross

EPA's standard of performance is technology neutral, affected sources may comply with it by co-firing hydrogen.</td></tr>
<tr><td colspan="4">For new and existing units installing control technologies, a 1-year extension is available in situations in which implementation delays are due to factors beyond the EGU owner/operator's control. For existing units with cease operations dates, a 1-year extension is available in situations in which the unit is needed for reliability through a reliability assurance mechanism, provided appropriate documentation is submitted.</td></tr>
<tr><td colspan="4">Major Modifications 111(b) Coal-fired Steam Generators: Standards of performance for coal-fired units that undertake a large modification (i.e., increases hourly emission rate by more than 10%) mirror the emission guidelines for existing coal-fired steam generators.</td></tr>
</table>

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 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.

Revision of Effluent Limitation Guidelines

The Clean Water Act further requires the EPA to periodically review and, if appropriate, revise technology-based 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;

[21] Not a product of the EPA. *See* https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power for official EPA produced information.

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.

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 Rodemacher 2 at 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. The rule was finalized on May 9, 2024. The new discharge limits of interest include the following:

- The zero discharge limit for bottom ash transfer water remains in place, with compliance allowed for generating units that permanently cease coal combustion by 2028.
- For combustion residual leachate, the rule establishes a zero-discharge limit on wastewater discharged during the plant's operational life. The compliance date is set for as soon as possible, beginning 60 days after publication in the Federal Register, but no later than December 31, 2029.
- Non-zero limits are established for leachate discharged following plant retirement.
- Legacy wastewater discharged during closure (from impoundments) is subject to numeric limits for mercury and arsenic.

Solid Waste Disposal – Coal Combustion Residuals ("CCR")

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. The rule requires owners/operators of existing CCR surface impoundments to determine whether the impoundment qualifies as having a liner by October 17, 2016.

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, such as the Rodemacher 2 bottom ash impoundment at Brame, do not have synthetic components and therefore, according to the court opinion, would not be adequately protective.

In 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 an alternative closure request to the EPA in the fourth quarter of 2020 for the continued operation of the bottom ash impoundment at Brame with ceasing of boiler operation and closure of the bottom ash impoundment taking place on October 17, 2028. Cleco Power is currently awaiting EPA approval of its request for the Rodemacher 2 bottom ash impoundment at Brame.

Section 7: Resource Needs and Other IRP Assumptions

MISO Market Utilization

MISO utilizes its PRA to ensure LSEs have sufficient 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, but may be limited by MISO rules. 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 sufficient to meet the total MISO system peak plus reserves.[22] 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 farther 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. If capacity offered into the MISO PRA is insufficient to meet load requirements, the PRA will still set a price at or above the Cost of New Entry ("CONE") for a single season or a maximum of one year. However, MISO will not have enough capacity to meet load requirements. At that point, any load sheds or other emergency actions taken by MISO could potentially affect all load-serving entities, not just those that relied on the PRA. Therefore, reasonable and responsible resource planning necessitates a plan for physical resources. For these reasons, MISO's annual PRA should not be relied upon as a long-term source of capacity. Cleco Power will continue to utilize the PRA procedures annually as required by MISO but will not depend 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 ("ESG") 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 Interim IRP Report; 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

[22] The auction clearing price may be different between local resource zones dependent upon the unique constraints between zones and resources located in each zone.

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 adding 240 MW of solar generation via the Dolet Hills Solar PPA (described below). Rodemacher 2, a PRB coal plant, will cease coal-fired operations in 2027 due to EPA requirements to close or retrofit large surface impoundments that contain coal combustion residuals. Madison 3 is currently scheduled to be retired by the end of 2038 due to the environmental requirements of Clean Air Act Rule 111 BSER.

Project Diamond Vault

In April 2022, Cleco Power announced Project Diamond Vault, which aimed to reduce up to 95% of carbon dioxide emissions from Madison Unit 3 using various CCS technologies. However, due to increased estimated investment requirements and the current economic and financing environment, Cleco Power has decided to discontinue Project Diamond Vault in its current form. As a result, that project was not considered in the interim IRP.

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, 2027, and continuing through the end of the study period (2042). The Dolet Hills Solar PPA was authorized by the Commission in Order No. U-36502.

Resource Alternatives

Supply Side Resources

Cleco Power engaged 1898 & Co. to identify viable supply-side resource alternatives. The technology assumptions for CTs and CCGTs are described in **Table 7.1: New Combustion Turbine Technologies** below. Solid fuel options were not considered in this Interim IRP Report.

Table 7.1: New Combustion Turbine Technologies

2025 \$	CCGT with CCS	CCGT	CT
Total Overnight Cost \$/kW	\$3,860	\$2,010	\$1,440
Size MW	625	665	230
FOM \$/kW - year	\$28.20	\$8.72	\$9.49
VOM \$/MWh	\$3.05	\$1.05	\$0.51
CCS VOM \$/MWh	\$2.00		
Heat Rate (Btu/kWh)	6,640	6,340	9,960
NOx (lbs./MMBtu)	0.007	0.007	0.007
SO2 (lbs./MMBtu)	<0.002	<0.002	<0.002
CO2 (lbs./MMBtu)	6	120	120
Depreciable Life	40	40	40

Renewable resources modeled are shown below in Table 7.2. The table illustrates overnight capital costs without tax incentives. Cleco Power did not include a production tax credit in this Interim IRP Report.

Table 7.2: New Renewable Technologies

2025 $	Battery Storage	Solar PV with Tracking	Solar PV with Storage ("Hybrid")
Size (MW)	100	100	100
FOM ($/kW - year)	$37.00	$16.00	$51.00
Total ($/kW)	$1,520	$1,886	$3,042
Depreciable Life	20	20	20
Capacity Factor	17%	25%	23%

A "hybrid" resource is a renewable project consisting of 100 MW of single-axis solar photovoltaic generation with 100 MW of four-hour battery energy storage system.

Capacity Limits for Potential Resources

Cleco Power established resource limits for technology options used in the studies. Table 7.3 below shows the limits used for each potential technology. The "Annual Max" column indicates the number of units Cleco Power is allowed to build in one year. These annual maximums were constrained by reasonable capitalization and execution assumptions.

Table 7.3: Capacity Limits

Resource	Annual Max
CCGT with CCS	1
CCGT with CCS	1
CT	2
Battery Storage	3
Solar PV (Tracking)	3
Solar PV with Storage	3

<u>Sensitivity Analyses</u>

Cleco Power conducted sensitivity analyses by adjusting major input variables. Sensitivity cases include the following:

- Base load, base gas;
- Base load, high gas;
- Base load, low gas;
- Upside load, base gas;

- Upside load, high gas; and
- Upside load, low gas.

Load Sensitivities

Cleco Power's Interim IRP report studied two different load scenarios: the Reference Case and the Upside Case. The Upside Case assumes adoption of probability-weighted potential economic development and marketing projects, in addition to organic load growth.

Environmental Sensitivities

CO_2 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 developed a portfolio using CO_2 cost that applies a \$/ton cost to every ton of CO_2 emitted. The cost of CO_2 was included as an input to the model and thus was allowed to influence the dispatch of each generator in the development of the portfolio. The CO_2 price curve was supplied to Cleco Power by Filsinger Energy Partners.

Seasonal Accredited Capacity

As discussed in Section 5 above, Cleco Power assessed changes in seasonal capacity allocations and identified a downside SAC value for each season, as shown in Table 7.4. These values reflect a 95% confidence for the average change from season to season and do not represent the maximum potential downside change.

Table 7.4: Downside Seasonal Accredited Capacity Reduction in MW

Season	Reduction in SAC MW
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Pre-Screening Environmental Rules Affecting Coal-Fired Generation

As discussed earlier, under the current Clean Air Act 111 BSER requirements, Madison 3 must be co-fired with natural gas by January 1, 2030, and retire by the end of year 2038 if it is not subsequently retrofitted with CCS. If Madison 3 is not co-fired, it must retire by the end of 2031.[23]

Additionally, as required by the "Environmental and Dispatch Commitments" specified in LPSC Order No. U-36923 (as described in the Executive Summary, above), Cleco Power committed to evaluating options for MPS3 following completion of the Front-End Engineering Design ("FEED") study for carbon capture identified in its 2021 IRP Final Report. This evaluation included considering the use of the DOE's Energy Infrastructure Reinvestment ("DOE EIR") program to mitigate the customer impact of retrofitting MPS3 with CCS. However, the One Big Beautiful Bill ("OBBB") Act amended the DOE EIR, so it no longer supports financing projects that reduce or avoid air pollutants or GHG emissions. As a result, in the evaluation, the remaining net book value for MPS3 was securitized over a 20-year period and was not influenced by the DOE EIR.

Since the Company decided not to pursue CCS in its current form, MPS3 was evaluated under rule 111 BSER (b) and (d). MPS3 must either be co-fired with natural gas and retire by end of year 2038, or retire at the end of year 2031.

Rodemacher 2 is currently scheduled to cease coal-fired operations in 2027 due to environmental requirements mandating closure of the ash impoundments by October 2028. RPS2 was evaluated under two scenarios: one in which the unit is not repowered to use natural gas and retires at the end of 2027, and a second scenario in which the unit is repowered to use natural gas and retires at the end of 2035.

To identify the least cost options for MPS3 and RPS2, Cleco Power considered several factors, including reliability challenges in MISO, Cleco Power's current generating fleet, uncontracted resources available in LRZ 9, the extended time required to navigate MISO's transmission queue for new resources, and the current state of original equipment manufacturers to supply utility-scale generation systems. Based on this analysis, Cleco Power determined that co-firing MPS3 and retiring the unit at the end of 2038, along with repowering RPS2 and retiring the unit at the end of 2035, were the least cost options.

The least cost options were modeled in this Interim IRP report.

IRP Scenarios and Sensitivities

To support this Interim IRP Report, Cleco Power identified several key assumptions regarding portfolio components to test. In addition to evaluating Madison 3 being co-fired with natural gas, the assumptions included determining the timing for the retirement of Madison 3 and the timing for the retirement of Rodemacher 2.

[23] Please note that Project Diamond Vault was discussed earlier in this Interim IRP report.

These portfolio component assumptions include whether the EPA's CAA Section 111 BSER will be in effect, the impacts from high load-factor additions and increased load growth, and the effects of MISO SAC volatility.

An examination of the assumptions regarding the portfolio components discussed above allows for the informed development of an action plan for this Interim IRP Report. Table 7.5 below summarizes the scenarios constructed for the Interim IRP report, based on these portfolio component assumptions. Each scenario's assumptions were utilized to develop resource portfolios, with the assumptions for each modeling run depending on the sensitivities under which each scenario was developed.

Table 7.5: Summary of Scenarios Modeled

Scenario	Environmental Regulation	Peak Load	Natural Gas Prices	Seasonal Accredited Capacity (SAC)	CO2 Tax
S1	111 BSER (b) (d) ELG/CCR	Base	Base	Base	No
S2	111 BSER (d) ELG/CCR	Base	Base	Base	No
S3	111 BSER (d) ELG/CCR	Upside	Base	Downside	No
S4	111 BSER (d) ELG/CCR	Upside	High	Downside	Yes

Financial Assumptions

Financial assumptions used in the development of this Interim IRP Report are listed in Table 7.6.

Table 7.6: Financial Assumptions

Assumption	Value
Inflation Rate	2.5%
Wtd. Avg. Cost of Capital	7.66%
Discount Rate	7.66%
Income Tax Rate	26.923%

Section 8: Results and Modeling

Modeling

The Company retained 1898 & Co to handle all portfolio development and production cost modeling using the EnCompass Production Cost Modeling software ("EnCompass"), which is licensed through Yes Energy. EnCompass is a widely adopted, industry-standard platform used by electric utilities, consultants, and regulators for long-term planning, power market price forecasting, regulatory impact assessment, and system performance evaluation across various scenarios. Additionally, EnCompass is a chronological unit commitment and dispatch model, employing a mixed integer programming approach to determine optimal solutions for capacity expansion, economic dispatch, and unit commitment challenges. The model is designed to simulate electric system operations under real-world constraints.

All portfolios were initially modeled for long-term capacity buildouts that were most economical and met Cleco Power's PRM requirements. In some cases, the modeled long-term capacity plans were adjusted to account for qualitative considerations, such as reliability in a capacity-constrained MISO and the reliability of aging EGUs. Once long-term capacity plans were developed for each portfolio, production cost modeling using EnCompass was performed to determine power supply production costs. The results for each portfolio were analyzed, with a focus on the differences in key assumptions, to help develop the Preferred Portfolio. The remainder of this section discusses the portfolio modeling results, including long-term capacity expansion and production costing for each scenario, as well as the development and performance of the Preferred Portfolio.

Pre-Screening Modeling Results

Madison 3 was modeled in two different portfolio scenarios. In the first scenario, Madison 3 was not co-fired with natural gas and was retired in 2031. In the second scenario, Madison 3 was co-fired with natural gas starting January 1, 2030, and was scheduled to retire at the end of 2038, as it was not subsequently retrofitted with CCS.[24]

Environmental Regulation	111 BSER (d)
Peak Load	Base
Natural Gas Prices	Base
Seasonal Accredited Capacity	Base
CO2 Tax	No

[24] Rule 111 (d) requires existing coal-fired boilers to co-fire with natural gas by January 1, 2030, or permanently cease operating before January 1, 2032. The rule additionally requires coal-fired boilers operating after January 1, 2032, to permanently cease operating before January 1, 2039, unless equipped with CCS.

Table 8.1: Madison 3 Scenarios

Year	Madison 3 Retire 2031	Madison 3 Retire 2038
2028	RPS2 Repower	RPS2 Repower
2029		MPS3 Co-Fire
2031	MPS3 Retire	
2032	CCGT	Hybrid
2035	NPS1 and RPS2 Retire	NPS1 and RPS2 Retire
2036	CCGT	CCGT
2038		MPS3 Retire
2039		CCGT
2043	Hybrid	

Rodemacher 2 was modeled in two different portfolio scenarios. In the first scenario, Rodemacher 2 was not repowered to be fueled with natural gas and was retired at the end of 2027. In the second scenario, Rodemacher 2 was repowered to be fueled with natural gas and was scheduled to retire at the end of 2035.

Environmental Regulation	111 BSER (d) ELG/CCR
Peak Load	Base
Natural Gas Prices	Base
Seasonal Accredited Capacity	Base
CO2 Tax	No

Table 8.2: Rodemacher 2 Scenarios

Year	Rodemacher 2 Retire 2027	Rodemacher 2 Retire 2035
2028 - 2032	PPA 50MW	
2027	RPS2 Retire	
2028		RPS2 Repower
2029	MPS3 Co-Fire	MPS3 Co-Fire
2032	CT	
2034		Hybrid
2035	NPS1 Retire	NPS1 and RPS2 Retire
2036	CCGT	CCGT
2038	MPS3 Retire	MPS3 Retire
2042		CT
2046	Hybrid	

Portfolio Modeling Results

For this Interim IRP Report, the modeling process was conducted in two distinct steps: long-term capacity expansion and production cost (economic dispatch). During the capacity expansion phase, the objective was to determine the least-cost mix of new and existing generating resources necessary to reliably meet demand. This stage of modeling had to comply with any applicable reliability standards, environmental regulations, and policy mandates throughout the study period.

The optimized portfolios developed in the capacity expansion phase of modeling were subsequently evaluated through production cost modeling simulations. These simulations optimize unit commitment and economic dispatch on an hourly basis, offering a more granular operational view of the system. Through production cost modeling, a detailed assessment of the operational feasibility of resources, production costs, emissions profiles, and generation performance across a range of future sensitivities were evaluated.

Each of the scenarios listed in Tables 8.1 and 8.2 above was evaluated during the long-term capacity expansion stage of this assessment. The resulting optimized portfolios were then analyzed under a variety of potential future sensitivities to assess the robustness of each portfolio. The buildout results for Scenarios 1 through 4 are summarized below.

Table 8.3: Portfolio Results for Scenarios 1 through 4[25]

Year	Portfolio 1	Portfolio 2	Portfolio 2a	Portfolio 3	Portfolio 4
Environmental Regulation	111 BSER (b) (d) ELG/CCR	111 BSER (d) ELG/CCR		111 BSER (d) ELG/CCR	111 BSER (d) ELG/CCR
Peak Load	Base	Base		Upside	Upside
Natural Gas Prices	Base	Base		Base	High
Seasonal Accredited Capacity	Base	Base		Downside	Downside
CO2 Tax	No	No		No	Yes

Year	Portfolio 1	Portfolio 2	Portfolio 2a	Portfolio 3	Portfolio 4
2027-2032				PPA 200MW	PPA 300MW
2031					
2032				CCGT	
2033		CCGT			CCGT
2034	CT		Hybrid		
2035	CT / (NPS1 / RPS2)[26]	(NPS1 / RPS2)	(NPS1 / RPS2)	CT / (NPS1 / RPS2)	(NPS1 / RPS2)
2036	CT / Hybrid (2)		CCGT	CT	CT
2037	Hybrid				Hybrid
2038	(MPS3)	CT / (MPS3)	(MPS3)	(MPS3)	Hybrid (MPS3)
2039	CCGT-CCS	CCGT	CCGT	CCGT	CCGT
2040					
2041					

[25] Please note that co-fire of Madison 3 and repower of Rodemacher 2 are not shown in this table. Only additions or retirements are provided in this table.

[26] (RED) = Generator Retired.

Year	Portfolio 1	Portfolio 2	Portfolio 2a	Portfolio 3	Portfolio 4
2042	Hybrid				
2043	Hybrid				
2044					
2045					
2046		CT			

Comparison of Portfolio Modeling Results

Portfolio 1

Portfolio 1 represents the model's economic resource selection based on the assumption that Clean Air Act Section 111 BSER (b) and (d) remain in place and that the ELG and CCR regulations continue to be in effect. Consequently, Madison 3 is co-fired with natural gas at a ratio of 55% natural gas to 45% solid fuel, and Rodemacher 2 is repowered entirely to natural gas to comply with the standards. Furthermore, new combined cycle units are required to include carbon capture technology, and peaking thermal resources are restricted to a 40% capacity factor.

The table below shows resource additions and key retirement under the base case assumptions as determined by the model.

Table 8.4: Portfolio 1 Resource Selection

Year	Portfolio 1
2028	RPS2 Repowered
2029	MPS3 Co-Fired
2034	CT
2035	NPS1 and RPS2 Retired CT
2036	CT Hybrid (2)
2037	Hybrid
2038	MPS3 Retired
2039	CCGT with CCS
2042	Hybrid
2043	Hybrid

In the near term, multiple CTs and hybrid resources were selected to address energy and capacity needs. Following the retirement of Madison 3 in 2038, a CCGT with CCS was chosen as a replacement resource. To support long-term routine load growth, additional hybrid capacity is selected in the later years.

Portfolio 2

Portfolio 2 is identified as the Preferred Portfolio and represents the model's economic resource selection under the assumption that 111 BSER (b) is rescinded and ELG/CCR remain in effect. All other assumptions are considered base assumptions. For unit and cost efficiency, Madison 3 is co-fired with a mix of 55% Natural Gas and 45% Solid Fuel, and Rodemacher 2 is repowered to use natural gas. To enhance reliability, a CCGT is added in 2033 to address the uncertainty and volatility in the MISO market, the seasonal resource adequacy construct, and the challenges posed by aging generating assets.

The table below shows resource additions and key retirements under the base case assumptions as determined by the model.

Table 8.5: Portfolio 2 Resource Selection

Year	Portfolio 2
2027	RPS2 Repowered
2029	MPS3 Co-Fired
2033	CCGT
2035	NPS1 and RPS2 Retired
2038	MPS3 Retired CT
2039	CCGT
2046	CT

With Clean Air Act Section 111 BSER (b) rescinded and the ELG and CCR regulations continuing in effect, a CCGT was selected in 2033 to address reliability concerns. These concerns stem from MISO resource adequacy changes that create significant uncertainty in seasonal planning reserve margin requirements, volatility in MISO's allocated capacity for existing resources, and the risk associated with aging generation in a market that has limited uncontracted resources and an alarming increase in emergency notices from MISO. Multiple CCGTs were chosen to accommodate increasing load demands: one in 2033, which would be fully utilized by 2035/2036 following the retirement of Nesbitt 1 and Rodemacher 2, and another in 2039 to replace Madison 3. Additionally, two F-Class units were selected to provide extra peaking capacity to support routine load growth.

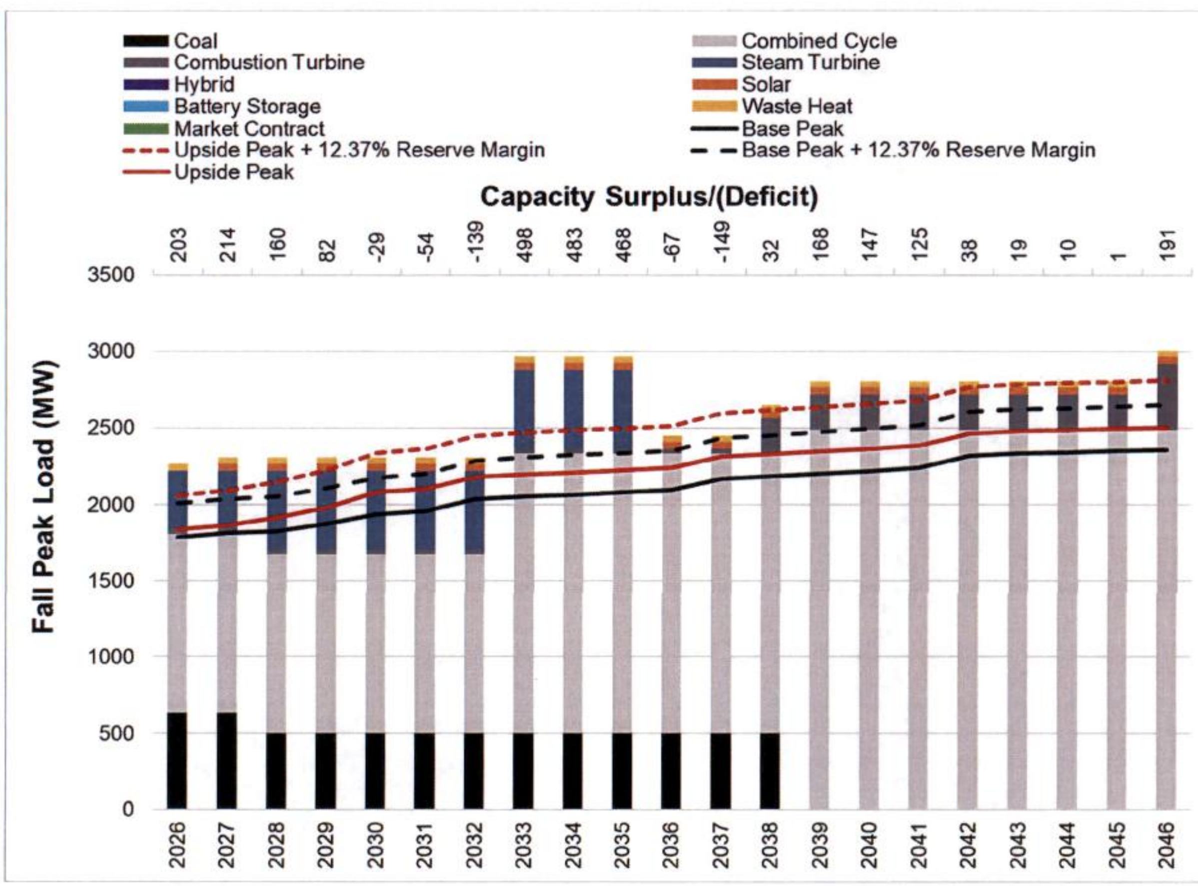
Since the Interim IRP Report serves as a bridge to the Company's next full IRP under the IRP General Order (which, as noted previously, will initiate in October 2025), the Company is recommending the addition of a CCGT in 2032 or 2033, along with co-firing Madison 3, and repowering Rodemacher 2. The Company plans to issue a Request for Proposals ("RFP") for dispatchable generating assets, including a self-build project for certification of the resource addition. Other assets identified in the Preferred Portfolio will be evaluated in the next IRP report.

Portfolio 2 mitigates the reliability concerns discussed in this Interim IRP Report, including:

- Uncertainty of MISO's PRMR due to its RBDC process,
- Volatility of the allocated capacity due to MISO's SAC process,
- Unknown impacts of MISO's future DLOL process, and
- The potential loss of one of the Company's aged EGUs.

Portfolio 2 further enables the Company to meet the energy requirements of upside economic development load growth in Louisiana.

Figure 8.1: Portfolio 2 Capacity Surplus (Deficit) – Fall Season



Portfolio 2a

Portfolio 2a represents the model's economic resource selection under the assumption that Clean Air Act Section 111 BSER (b) is rescinded while the ELG and CCR regulations remain in effect. All other assumptions are considered base assumptions. For unit and cost efficiency, Madison 3 is co-fired with a mix of 55% natural gas and 45% solid fuel, and Rodemacher 2 is repowered to use natural gas instead of coal.

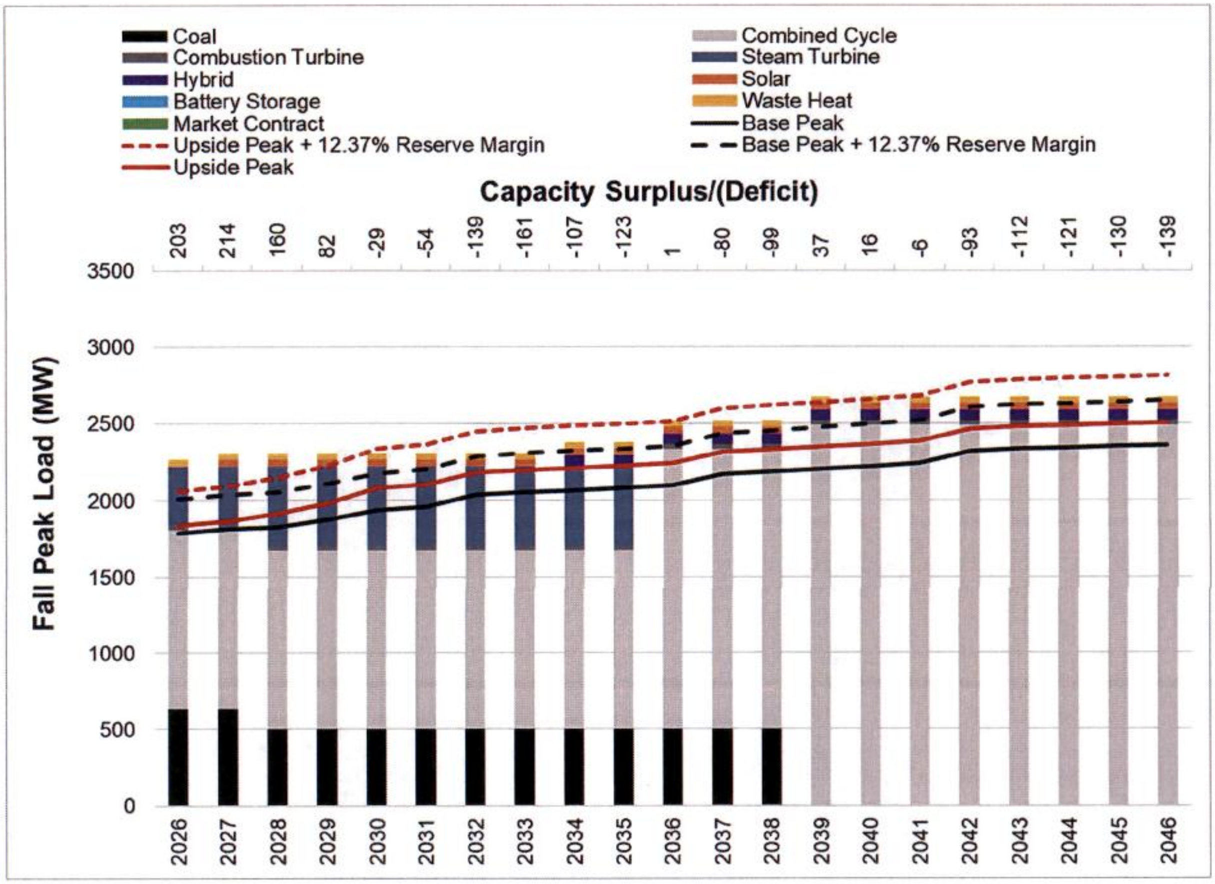
This portfolio is recognized as the lowest cost option; however, it does not sufficiently address reliability concerns. The loss of an aging generating asset would not be adequately mitigated with this portfolio. Additionally, this portfolio relies on capacity from non-dispatchable generation units.

The table below shows resource additions and key retirement under the base case assumptions as determined by the model.

Table 8.6: Portfolio 2a Resource Selection

Year	Portfolio 2a
2028	RPS2 Repowered
2029	MPS3 Co-Fired
2034	Hybrid
2035	NPS1 and RPS2 Retired
2036	CCGT
2038	MPS3 Retired
2039	CCGT

Figure 8.2: Portfolio 2a Capacity Surplus (Deficit) – Fall Season



Portfolio 3

Portfolio 3 envisions a future where Clean Air Act Section 111 BSER (b) is rescinded while the ELG and CCR regulations remain in effect. Additionally, it considers scenarios where load growth exceeds the base forecast and SAC is degraded due to changing market conditions. Specifically, SAC values are decreased by the amounts noted in Table 7.4: Downside Seasonal Accredited Capacity Reduction in MW. This reflects a decrease in the average SAC for Cleco Power's entire existing fleet, rather than the maximum reduction in seasonal SAC.

The table below shows resource additions and key retirement under the base case assumptions as determined by the model.

Table 8.7: Portfolio 3 Resource Selection

Year	Portfolio 3
2028-2032	Capacity Contract 200 MW
2028	RPS2 Repowered
2029	MPS3 Co-Fired
2032	CCGT
2035	CT
2035	NPS1 and RPS2 Retired
2036	CT
2038	MPS3 Retired
2039	CCGT

Early in the study period, increased load resulted in a capacity shortfall, which was initially addressed with capacity market contracts, as the immediate demand made building new resources unfeasible. Once these capacity contracts expire, a CCGT is selected to replace the capacity, followed by a CT in 2035 to provide additional peaking capacity. After the retirement of NPS1 and RPS2, they are replaced by an additional CT. Similarly, following the retirement of MPS3, it is replaced by a CCGT.

Portfolio 4

Portfolio 4 represents the model's economic resource selection under conditions that are unfavorable for thermal generation. In this scenario, Clean Air Act Section 111 BSER (b) is rescinded while the ELG and CCR regulation remain in effect. The scenario also considers higher load growth, SAC deration by the amounts noted in Table 7.4: Downside Seasonal Accredited Capacity Reduction in MW, high natural gas pricing, and an increase in CO_2 taxes, all of which elevate costs for thermal units.

Table 8.8: Portfolio 4 Resource Selection

Year	Portfolio 4
2028-2032	Capacity Contract 300 MW
2028	RPS2 Repowered
2029	MPS3 Co-Fired
2033	CCGT
2035	NPS1 and RPS2 Retired
2036	CT
2037	Hybrid
2038	MPS3 Retired Hybrid
2039	CCGT

In response to near-term load growth, the model selects 300 MW of capacity contracts, which are subsequently replaced by a CCGT in 2033. When NPS1 and RPS2 retire, they are replaced with CTs. To accommodate routine load growth, hybrid units are selected in 2037 and 2038. Finally, upon the retirement of MPS3, it is replaced with a CCGT.

<u>Incremental Levelized Cost of Energy</u>

The Incremental Levelized Cost of Energy ("LCOE") illustrates the levelized cost cross-testing results for the portfolios evaluated:

Pre-Screening Results for MPS3 and RPS2

Co-firing MPS3 to retain the capacity and energy from the unit through 2038 at a minimum has an incremental LCOE that is on average 6% lower, with a range of 3%-8% lower across the load and natural gas sensitivities, versus retiring the unit at the end of 2031 with 29 years of recoverable depreciable life remaining. The standard deviation of the incremental LCOE is 11% lower than if the unit was retired in 2031, so the variability around the lower incremental LCOE is less risky.

Repowering RPS2 to retain the capacity and energy from the unit through 2035 has an incremental LCOE that is on average 7% lower, with a range of 6%-8% lower across the load and natural gas sensitivities, versus retiring the unit in 2027. The standard deviation of the incremental LCOE is 7% lower than if the unit was retired in 2027, so the variability around the lower incremental LCOE is less risky.

Table 8.9: Pre-Screening Madison 3 and Rodemacher 2

		Incremental LCOE ($/MWh)			
Load Sensitivity	Gas Sensitivity	MPS3 Retire 2031	MPS3 Retire 2038	RPS2 Retire 2027	RPS2 Retire 2035
Base	Base	$18.67	$17.40	$18.60	$17.40
Base	High	$18.31	$17.33	$18.89	$17.33
Base	Low	$18.27	$16.79	$17.92	$16.79
Upside	Base	$16.00	$14.87	$16.12	$14.87
Upside	High	$14.94	$14.44	$15.67	$14.44
Upside	Low	$15.53	$14.37	$15.30	$14.37
	Average	$16.95	$15.87	$17.08	$15.87
	Standard Dev.	$1.64	$1.46	$1.57	$1.46

Portfolios 1 - 4

Table 8.10: Portfolios 1 - 4

		Incremental LCOE ($/MWh)				
Load Sensitivity	Gas Sensitivity	Portfolio 1	Portfolio 2	Portfolio 2a	Portfolio 3	Portfolio 4
Base	Base	$27.59	$19.98	$17.40	$24.64	$31.36
Base	High	$27.46	$20.24	$17.33	$24.93	$30.85
Base	Low	$27.08	$19.40	$16.79	$27.02	$37.42
Upside	Base	$24.74	$17.19	$14.87	$21.35	$29.26
Upside	High	$24.24	$16.82	$14.44	$20.99	$28.90
Upside	Low	$24.11	$16.66	$14.37	$20.83	$30.50
	Average	$25.87	$18.38	$15.87	$23.30	$31.38
	Standard Dev.	$1.67	$1.66	$1.46	$2.59	$3.10

Section 9: Preferred Portfolio and Action Plan

Development of Preferred Portfolio

As noted above, the objective of Cleco Power in this Interim IRP is to develop a solution to provide reliable, resilient, and affordable power to satisfy the needs of the Company's customers. This entails a careful consideration and balancing of reliability on one hand and customer affordability on the other hand. This Interim IRP represents Cleco Power's proposed solution to optimize the Company's investments in reliability to ensure the lowest reasonable cost of reliable service to the Company's customers. This Interim IRP Report identifies a Preferred Portfolio designed to provide this solution, while also considering the potential for upside-load growth. The rapid growth of data centers, industrial, and other large load opportunities provides a significant potential to increase the Company's load requirements and would require an update to this Interim IRP. The near-term resources provided in the Preferred Portfolio nonetheless would still be required and would be encompassed in such an update.

While this Interim IRP Report considers various future scenarios, including future drivers such as Clean Air Act Section 111 BSER, the ELG and CCR regulations, higher loads, fluctuating natural gas prices, volatility in MISO's capacity accreditation, and uncertainty in the annual PRMR for each season, the Preferred Portfolio is designed to treat these future drivers as unknowns. Specifically, the Preferred Portfolio must incorporate resource additions and retirements that can accommodate an uncertain future. Considering this, the Preferred Portfolio is created to be proactive regarding near-term reliability, which is critical as MISO's resource adequacy construct changes in the near term. The Preferred Portfolio is also constrained by the fact that this Interim IRP Report is an update to Cleco Power's 2021 IRP Final Report, reflecting rapidly occurring market changes, and serves as a bridge to Cleco Power's next IRP to be initiated in October 2025 in accordance with the IRP General Order.

Preferred Portfolio[27]

Cleco Power's current generation fleet is a diversified fleet made up of primarily natural gas, coal, and petcoke EGUs. The following Preferred 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.

Preferred Portfolio Elements

- **Co-firing** Madison 3 by January 1, 2030
- **Repowering** of Rodemacher 2 at the end of 2027
- **Retirement** of Rodemacher 2 in 2035[28]

[27] The Preferred Portfolio was assembled on selections by the EnCompass model using load and cost assumptions described in this Interim IRP Report, which will be used in determining Cleco Power's Action Plan. Therefore, the Preferred Portfolio is used as a guide in determining potential RFP parameters.

[28] The retirement of Rodemacher 2 is dependent on a joint owner agreement.

- **Retirement** of Nesbitt 1 in 2035[29]
- **Maintain operation** of Madison 3 as a co-fired unit through 2038, pending further expected changes in rule 111 BSER (b) (d) of the Clean Air Act
- **Maintain operation** of Coughlin 6 and 7 through 2044
- **Maintain operation** of Acadia through 2045
- **Maintain operation** of St. Mary Clean Energy Center
- **Complete** Dolet Hills Solar Project
- **Addition** of CCGT by 2033
- **Issue** dispatchable RFP with self-build option for the CCGT identified in the Preferred Portfolio in this Interim IRP Report. Cleco Power notes that the RFP for approximately 700 MW of dispatchable generation is inclusive of the 500 MW of dispatchable generation need identified in the Final 2021 IRP Report.
- **Complete** currently ongoing renewable RFP
- **Continue** issuance of additional renewable RFPs to respond to customer preferences and diversity of Cleco Power's generating portfolio

The Preferred Portfolio outperforms all other portfolios in all cases, except for portfolio 2a, which is the least cost portfolio. However, portfolio 2a does not adequately mitigate the reliability concerns identified throughout this Interim IRP Report. The Preferred Portfolio acts as a functional hedge to offset potential grid emergencies from the loss of aged generation in a market that currently has: capacity constraints within LRZ 9; volatility introduced by MISO's SAC construct; and an increase in emergency events affecting both Cleco Power's service territory and MISO South generally.

The Preferred Portfolio is capable of meeting Cleco Power's currently projected capacity and energy requirements; and focuses on the fundamental need for generation resources that can be dispatched in all hours of need. The Preferred Portfolio also provides Cleco Power with flexibility to respond to changes in circumstances, including the uncertainties of environmental regulations and/or other regulatory rulemakings.

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

- **Changes in load or load growth**

  Cleco Power may gain or lose retail 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 EGUs, which would materially influence the quantity of resources

[29] The retirement of Nesbitt 1 is dependent on future environmental rules and aging infrastructure costs.

procured in an RFP. Additionally, changes to the MISO SAC construct could materially impact Cleco Power's costs associated with continued maintenance of its EGUs.

- **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 volume of dispatchable and renewable capacity resources 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**

  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 materially impact the economics of bids, submitted in response to an RFP, resulting in a different mix of new resources than the Preferred Portfolio.

- **MISO queue**

  Proposed generation facilities must enter the MISO interconnection queue. Currently, the entire interconnection process requires multiple years 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

As provided in the IRP General 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."[30]

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, changes in the MISO market including resource adequacy constructs, and other relevant factors to identify any warranted resource adjustments.

Existing Supply-Side Resources

Cleco Power will continue to maintain and operate:

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

- Brame Power Station
  - Continue planning and preparation to co-fire Madison 3 in accordance with Clean Air Act Section 111 BSER (d) requirements
  - Continue planning and preparation to repower Rodemacher 2 in accordance with the ELG and CCR regulations
- St. Mary Clean Energy Center
- Acadia Power Station
- Coughlin Power Station
- Teche 4
  - To be maintained as a black-start generation asset.

New Resources

Renewable Resource and Battery RFP Issuance 1

Cleco Power has an ongoing RFP for up to approximately 500 MW of renewable generation with a potential target commercial operation date prior to January 1, 2031, consistent with the Commission's Market Based Mechanism Order. The RFP also sought up to approximately 150 MW of battery storage options, both standalone and as project add-ons, to complement the renewable resource additions.

Dispatchable Resource RFP Issuance

An additional RFP will be considered for up to approximately 700 MW of accredited all-seasons capacity options that: can be dispatched to reliably match customer demand, and demonstrate a technological pathway to be carbon-free in the future. The 700 MW is inclusive of the 500 MW of dispatchable resource needs identified in the Final 2021 IRP Report and is needed to ensure reliability given a rapidly changing resource adequacy construct in MISO that did not exist when the Final 2021 IRP Report was filed in LPSC Docket No. I-36175. 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.

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.

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 Interim IRP Report due to many of the rules remaining uncertain 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 the Company's 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.