John T. Burnett
Vice President & General Counsel
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
(561) 304-5253

February 28, 2025

VIA ELECTRONIC FILING
Adam Teitzman, Commission Clerk
Division of Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20250011-EI
Petition by Florida Power & Light Company for Base Rate Increase

Dear Mr. Teitzman:

Attached for filing on behalf of Florida Power & Light Company ("FPL") in the above docket are the direct testimony and exhibits of FPL witness Andrew Whitley.

Please let me know if you have any questions regarding this submission.

Sincerely,

s/ John T. Burnett
John T. Burnett
Vice President & General Counsel
Florida Power & Light Company

(Document 10 of 30)

CERTIFICATE OF SERVICE
Docket 20250011-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service this 28th day of February 2025 to the following:

Shaw Stiller
Timothy Sparks
Florida Public Service Commission
Office of the General Counsel
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
sstiller@psc.state.fl.us
tsparks@psc.state.fl.us

Walt Trierweiler
Mary A. Wessling
Office of Public Counsel
c/o The Florida Legislature
111 W. Madison St., Rm 812
Tallahassee, Florida 32399-1400
trierweiler.walt@leg.state.fl.us
wessling.mary@leg.state.fl.us
Attorneys for the Citizens of the State of Florida

By: *s/ John T. Burnett*
John T. Burnett

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250011-EI

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF ANDREW W. WHITLEY

Filed: February 28, 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew W. Whitley. My business address is 700 Universe Blvd., Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Engineering Manager in the Integrated Resource Planning ("IRP") department of FPL's Finance Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. In my current position, I am responsible for the management and coordination of economic analyses that identify and evaluate resource alternatives to meet FPL's resource needs and maintain system reliability. The analyses I oversee are designed to determine the magnitude and timing of resource needs for FPL's system and are used to develop the Company's integrated resource plan.

Q. Please describe your educational background and professional experience.

A. I graduated from Lehigh University in 2004 with a Bachelor of Science in Mechanical Engineering. I joined FPL in 2004 as part of the Power Delivery team, undertaking various engineering duties related to initiating new service to FPL customers and maintaining the reliability of customers' existing services. In 2007, I joined the team now known as the IRP group. Since that time, I have been involved in and supported a variety of resource planning projects for FPL, including FPL's Ten Year Site Plans ("TYSP"), solar base rate adjustments, need determination proceedings for new power plants under the Florida Power Plant Siting Act (including the Okeechobee Clean

Energy Center in 2015 and the Dania Beach Clean Energy Center in 2018), base rate proceedings, and the Demand-Side Management ("DSM") Goals proceedings. I became the Manager of the IRP group in 2022 and have served as the project leader for FPL's TYSPs since 2022.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit AWW-1 Summary of FPL Resource Adequacy Study (Prepared by E3)
- Exhibit AWW-2 Load Forecasts Used in the Current Analyses
- Exhibit AWW-3 Fuel Cost Forecasts Used in the Current Analyses
- Exhibit AWW-4 CO_2 Compliance Cost Forecast Used in the Current Analyses
- Exhibit AWW-5 Economic Analysis Results for the Combined 2026 and 2027 Solar and Battery Additions
- Exhibit AWW-6 Economic Analysis Results for the Combined 2028 and 2029 Solar and Battery Additions
- Exhibit AWW-7 With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis
- Exhibit AWW-8 Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs.

Q. Are you sponsoring or co-sponsoring any Minimum Filing Requirements in this case?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the resource planning process undertaken by FPL to identify optimal resource additions for the 2026-2029 period. Specifically, I identify FPL's system needs and detail how the battery storage and photovoltaic ("PV") solar resource options identified through the Company's resource planning process most cost-effectively promote the dependability and reliability of FPL's system. My testimony also describes how recent and ongoing changes in FPL's generation resource portfolio support the transition of FPL's production cost of service methodology from a 12 coincident peak ("CP") and 1/13th methodology to a 12 CP and 25% methodology as detailed in the testimony of FPL witness DuBose. I also support the 3-gigawatt ("GW") maximum established under FPL's proposed Large Load Contract Service-1 ("LLCS-1") tariff, which is detailed in the testimony of FPL witness Cohen. Lastly, my testimony establishes the appropriate new monthly incentive payment levels for two of FPL's largest DSM programs: the Commercial/Industrial Demand Reduction ("CDR") and Commercial/Industrial Load Control ("CILC") programs.

Q. Please summarize your testimony.

FPL employs a comprehensive system planning analysis to identify reliable, timely, and cost-effective system additions that meet FPL's unique system needs and ensure sufficient capacity and energy are available to serve all FPL customers for every hour of the year. FPL undertook such an analysis in identifying utility-scale battery storage and PV solar additions that are proposed to enter service between 2026 and 2029.

As FPL's system continues to incorporate additional cost-effective solar generation, the Company is continuing to adapt its resource planning to ensure that customers' reliability needs are met through available, dispatchable resources that provide value to customers. Just as FPL's system has advanced and modernized over time, resource adequacy must also be modernized to consider conditions that affect the delivery of power in times of greatest need. To that end, FPL performed a comprehensive, stochastic loss of load probability ("LOLP") analysis to ensure that FPL's proposed system additions optimally address system needs for each hour of the year. The results of the stochastic LOLP analysis, which are detailed in my testimony, demonstrate that FPL has a need for resources to be added throughout years 2026 to 2029. Specifically, FPL must meet a 32,322 MW firm capacity need by 2027 in order to maintain its LOLP requirement in that year, and that reliability requirement increases to 34,102 MW in 2030, representing an increase of 1,780 MW over that timeframe.

The economic analyses presented through my testimony show that PV solar additions, combined with battery storage installations, most cost-effectively address the reliability needs identified through the stochastic analysis and generate significant customer savings. My testimony demonstrates that the deployment of 2,086 megawatts ("MW") of PV solar facilities in 2026 and 2027, along with 2,239 MW of battery storage installations over that same time period, is expected to create $1,942 million in cumulative present value revenue requirement ("CPVRR") savings for FPL's customers. The combination of solar and battery storage provides complementary benefits for FPL's system, incorporating FPL's most cost-effective generation resource and, concurrently, allowing for continued reliable operation of the electric system during times when solar facilities are not generating. Together, these resources are less costly than new natural gas fired generation and, unlike natural gas generation, can be added in the near term to address FPL's current reliability needs.

Not only are solar and battery storage optimal resources for the 2026 and 2027 timeframe, they continue to be the best resource options to address FPL's reliability needs in the latter years of FPL's four-year plan. FPL's proposed 3,278 MW of solar installations and 1,192 MW of battery installations in 2028 and 2029 are expected to create $2,213 million in CPVRR savings for customers, making them optimal resources as compared to other alternatives. These resources will continue the trend of providing fuel-free generation from solar combined with the flexibility and capacity from battery storage and will ensure FPL's bulk electric system is powered by reliable, cost-effective generation.

With the continued deployment of cost-effective solar, FPL's net system peak continues to push further into the evening hours. This means that FPL's incremental generation resource needs are moving to a time of the day when FPL's solar generation is producing less output. This transformation in our generation fleet supports the transition to a 12 CP and 25% methodology as described in the testimony of FPL witness DuBose, as this methodology best reflects the realities of FPL's system and its incremental generation needs during peak hours.

Just as FPL's grid and resource supply continue to evolve, so does the nature of the customers who are being added to the system, requiring the Company to refine certain features of service and cost assignment. One such feature is the LLCS-1 tariff described in the testimony of FPL witness Cohen. Participation in this tariff, which is tailored to large load customers entering FPL's service area, must be capped in order to ensure that FPL has the generation supply resources needed to safely, reliably, and adequately serve all of its customers. The limitation of 3 GW for this service during the term of our proposed four-year plan, which my testimony supports, is a reasonable limitation given the resources that FPL could potentially add in the near-term to meet the needs of new customers with large electric loads.

The nature of FPL's system also affects the operational value and cost-effectiveness of FPL's CDR and CILC programs. Currently, the incentive levels for these programs do not align with the operational value that they provide to FPL and its general body of customers. As such, FPL proposes to lower the monthly incentive payment for the CDR program from its current level of $8.76/kW to $6.22/kW. FPL's CILC rate will be adjusted accordingly, as addressed by FPL witness Cohen. The revised incentive levels will ensure that the programs are still attractive to participants and do not burden non-participants with higher program costs than are needed to sustain the program.

II. RESOURCE ADDITIONS

Q. What generation resource additions associated with FPL's rate request is your testimony supporting?

A. My testimony supports the prudence of FPL's addition of utility-scale battery storage and solar generation proposed for years 2026 and 2027, as well as FPL's need for further additions of these resources in years 2028 and 2029. These additions, which were specifically identified through FPL's resource planning process as optimal and needed resources, will allow FPL to meet its capacity and energy requirements with reliable generation sources and are forecasted to generate billions of dollars in total savings for FPL's customers compared to other alternatives.

A. *Resource Planning – Process Overview*

Q. How does FPL determine its future demand and energy needs and how best to meet those needs?

A. There are three main goals of FPL's resource planning process:

1. Identify the timing of FPL's resource needs. The timing of future resource needs is largely determined by reliability standards, including planning reserve margin, generation-only reserve margin, and LOLP.
2. Identify the magnitude of these resource needs, *i.e.*, how many MW of capacity are needed to satisfy all reliability criteria.
3. Identify the type of resources, either supply-side or demand-side, that can meet the capacity needs while adding other resources that improve system economics. On an economic basis, this selection is determined by the option

that is projected to result in the lowest electric rates for FPL's customers while satisfying FPL's reliability standards.

Q. Please provide an overview of FPL's resource planning process.

A. FPL's resource planning process can be summarized by the following four tasks:

- Task 1: Determine the magnitude and timing of FPL's new resource needs to maintain a reliable system.
- Task 2: Identify the resource options and resource plans that are available to meet the determined magnitude and timing of FPL's resource needs (*i.e.*, identify the available competing options and resource plans).
- Task 3: Evaluate the competing resource options and resource plans based on system economics and non-economic factors.
- Task 4: Select a resource plan to meet the identified need.

Q. What are the reliability standards the Company uses to design its resource portfolio and determine the need for additional resources?

A. FPL uses three specific reliability criteria in projecting its future resource needs. The first criterion is a minimum total planning reserve margin ("PRM") of 20% for both summer and winter peak hours. The minimum 20% total PRM criterion was approved by the Commission in Order No. PSC-99-2507-S-EU issued in Docket No. 981890-EU.

The second reliability criterion used by FPL is an LOLP criterion. LOLP is a projection of how well an electric utility system may be able to meet its firm demand (*i.e.*, a measure of how often firm load may exceed available resources). In contrast to a reserve margin approach that looks at the one summer peak hour and the one winter peak hour, the LOLP approach looks at the peak hourly demand for each day of the year. The LOLP approach takes into consideration the probability of individual generators being out-of-service due to scheduled maintenance or forced outages, the variability of load, the variability of production from intermittent generation resources, and the availability of duration-limited resources, such as battery storage and demand response programs. An LOLP analysis models each of these variables to generate a multitude of scenarios and the associated probability of a generation shortfall in these scenarios can be calculated. LOLP is typically expressed in terms of “numbers of times per year” that the system firm demand cannot be served. FPL’s LOLP criterion is a maximum of 0.1 days per year, or one day in ten years. This LOLP criterion is commonly used throughout the electric utility industry and is consistent with North American Electric Reliability Corporation reliability planning standards.

The third reliability criterion used by FPL is a minimum generation-only reserve margin (“GRM”) of 10%. The issue of having a sufficient generation component of the projected total reserve margin has been discussed annually in FPL’s TYSP since 2011, and the GRM was adopted by FPL as a reliability criterion beginning in 2014. The GRM must be applied only after evaluating the amount of DSM in a resource plan.

Q. Has FPL expanded its reliability analysis to account for features that are specific to FPL’s evolving system?

A. Yes. FPL’s system has evolved over time such that the reliability analyses of the past do not sufficiently detect resource adequacy risks associated with FPL’s generation profile. As I referenced earlier, FPL's incorporation of cost-effective solar has increased to the extent that the peak hour of the year – *i.e.*, the hour of greatest demand on the system – is no longer the most critical hour for determining reliability need. Now, the most critical time for capacity on FPL's system is at peak net demand, which occurs between 5:00 p.m. and 8:00 p.m., when solar facilities are providing less generation output. For these hours, as well as all other hours throughout the year, FPL needs additional, more modernized modeling analysis to determine its resource adequacy and identify where its greatest resource needs lie. Thus, for its 2025 resource planning, FPL added a stochastic LOLP analysis tailored to its system to identify (1) hourly periods of the year where there is increased likelihood for a loss of load, and (2) available resources that can remediate the potential for that loss.

Q. How does stochastic LOLP modeling work?

A. Stochastic LOLP modeling incorporates vast amounts of data to develop a granular view of a utility's system adequacy in hour-by-hour segments. This modeling incorporates significantly more data in assessing system reliability than a traditional LOLP analysis, providing a substantially wider range of load and generation conditions across numerous scenarios. Through this analysis, a utility can more effectively determine the sufficiency of its hourly generation supply throughout the year, which, in turn, allows it to identify any needed system additions.

Q. How does the stochastic LOLP analysis differ from the reliability analyses FPL has previously used to identify resource needs?

A. The stochastic LOLP analysis incorporates a tremendous volume of system-specific data to develop a probabilistic hourly load and supply projection and identify the system's reliability needs. A traditional PRM analysis, however, provides a simplified look at system operation, examining only the peak demand hour at two times of the year – once in the winter and once in the summer – without considering the unique generation attributes of the utility's fleet. The PRM analysis therefore leaves an analytical shortcoming, particularly for systems that incorporate substantial renewable generation. For example, as FPL's solar generation portfolio has increased, the hours of the day with the least reserves are more likely to be found in the evening as the sun begins to set and solar generation decreases, which a PRM analysis does not fully reflect. In addition, the traditional PRM analysis also fails to capture the interactive effects of non-dispatchable generation and load, which have become increasingly challenging to predict and model. The stochastic LOLP analysis, on the other hand, accounts for and models these factors, assessing resource availability at every hour of the year and identifying the periods when reserves are most depleted, wherever they may fall.

The stochastic modeling also presents a more sophisticated analysis than FPL's prior LOLP analyses. A traditional LOLP analysis models expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages. The stochastic LOLP analysis, however, simulates a random selection of plant outages, which better reflects the unpredictable nature of unavailable generation as observed in normal system operations. Additionally, a traditional LOLP analysis models an expected solar generation profile, whereas the stochastic LOLP analysis produces a reliability assessment that captures the natural variability in solar production due to weather conditions. The stochastic LOLP model also better captures the synergistic interactions between load and non-dispatchable generation because it models the variability of each input separately.

Q. Did FPL engage an outside consultant to assist in developing FPL's stochastic LOLP analysis?

A. Yes. To assist with determining the hourly reliability needs specific to its system, FPL engaged Energy and Environmental Economics, Inc. ("E3"), a consulting firm with experience advising state agencies, regulators, system operators and utilities on energy policies. E3 provided advanced stochastic LOLP modeling that accounted for variability in, among other things, generating resource availability, generating resource output, and system load. The modeling also included an hourly assessment of FPL's system reliability. The scope of E3's analysis assessed the marginal reliability benefits of resources with disparate generating characteristics, such as thermal generation, solar, battery storage, and demand response.

Q. How were the inputs to the stochastic LOLP model developed?

A. E3 coordinated with FPL and used hourly temperature data from representative weather stations to develop hourly load profiles using a machine learning algorithm trained on actual load and temperatures from 2003 to 2023. E3 also used historic satellite data to simulate hourly solar generation at each of its current and future solar generating sites for the 1980 to 2023 period, as well as actual historical generating unit availability data to calculate an expected forced outage rate and a mean time to repair for every generating unit in the FPL fleet. The model used these inputs to randomly select which units may experience an outage at any given time within the simulations.

Q. What were the results of the stochastic LOLP analysis and how did FPL incorporate these results into its 2025 resource planning?

A. The stochastic analysis revealed that LOLP vulnerabilities will arise if FPL's resource planning is not modified. As shown in Exhibit AWW-1, FPL needs 32,322 MW of firm capacity to be available in 2027 in order to maintain an LOLP of 0.1 days-per-year in that year – and the required reliability need to reach the same 0.1 threshold increases to 34,102 MW in 2030, representing an increase of 1,780 MW. The stochastic analysis shows that not adding sufficient generation resources during the 2026 through 2029 time period to address the identified needs would cause FPL's LOLP to not meet the 0.1 days-per-year threshold and could potentially result in scenarios where FPL is unable to provide its customers with electricity, a circumstance that FPL's resource planning must address and avoid.

To address the resource need demonstrated through the stochastic analysis, FPL's resource planning process identified resources to timely address the need, while maintaining all reliability criteria, and tested the cost-effectiveness of the available resource options.

Q. What forecasts and assumptions did FPL use in its 2025 resource planning process?

A. Every year, FPL updates its forecasts as part of its resource planning process and in support of filing its yearly TYSP, including considerations of supply-side efficiencies. In its 2025 resource planning work, which supports the resource additions identified in my testimony, FPL is using the following forecasts:

1. A forecast of projected hourly load, dated November 8, 2024, which is provided with my testimony as Exhibit AWW-2;
2. A forecast of fuel prices (natural gas, coal, and oil), dated September 3, 2024, which is provided with my testimony as Exhibit AWW-3; and
3. A forecast of carbon dioxide ("CO_2") compliance costs, dated September 28, 2022, which is provided with my testimony as Exhibit AWW-4.

FPL's 2025 resource planning also reflects unit retirements that affect the Company's projected resource needs, including the retirement of Gulf Clean Energy Center Units 4 and 5 by the end of 2029.

Q. What is FPL's process for selecting new resources to meet identified system needs?

FPL's resource selection process is guided by the AURORA planning model and incorporates the stochastic LOLP modeling results I detailed earlier. The AURORA model utilizes sophisticated programming to conduct an extensive evaluation of potential resource plans that can meet the Company's reliability requirements. FPL has presented the Commission with outputs from this model in numerous prior proceedings, and it is being used to develop FPL's 2025 TYSP.

To develop a resource plan that is specific to FPL's needs, the AURORA model incorporates a number of forecasts and operating assumptions into its analysis including the following:

- The minimum 20% total Reserve Margin reliability criterion described earlier;
- Any additional resource needs from FPL's other reliability criteria;
- Forecasts for peak load, energy, fuel prices, and environmental compliance costs;
- Projections of future incremental DSM demand and energy additions, based on FPL's proposed DSM Plan, which will be filed by March 18, 2025;
- The existing capabilities of the units on FPL's systems, and any planned changes to those units; and
- Projections of fixed and variable costs, and the operating characteristics of a variety of generation options to meet FPL's resource needs in the future.

FPL ran the AURORA model with these assumptions to identify and test the cost-effectiveness of resource additions for inclusion in this proceeding as well as the 2025 TYSP.

I reviewed the underlying assumptions and modeling methodology, and they are reasonable and consistent with how FPL has conducted forecasts for prior investments that have been approved by the Commission.

Q. How does FPL forecast DSM and energy efficiency in its resource planning analysis?

A. FPL's resource planning assumes 100% achievement of its DSM and energy efficiency goals, which are approved by the Commission consistent with the Florida Energy Efficiency and Conservation Act ("FEECA"). Specifically, FPL accounts for the following projected DSM impacts as "line-item reductions" to the forecasts: (1) the impacts of incremental energy efficiency that have been implemented after the 2024 summer peaks have occurred, (2) projected impacts from incremental energy efficiency and load management, and (3) the impacts from previous signups in FPL's load management programs that will continue through 2034. Modeling DSM in this way reflects the full benefit associated with FPL's Commission-approved DSM programs.

Q. How have FPL's prior DSM efforts affected its system?

A. The Company's DSM efforts through the end of 2024 have resulted in a cumulative summer peak reduction of 5,695 MW at the generator and an estimated cumulative energy savings of 102,684 GWh at the generator. Without these reductions FPL would have required the equivalent of approximately 68 new 100 MW generating units to meet its peak load.

Q. How does FPL determine the cost-effectiveness of its potential resource options?

A. FPL assesses the CPVRR of potential resource options to make this determination. CPVRR is a metric focused on total system economics and rate impacts and allows for a comparative evaluation of the cost-effectiveness of various resource options. FPL assesses the CPVRR of competing resource alternatives by comparing the alternatives' abilities to economically meet an identical system load. This enables FPL to rank potential alternatives according to their respective impacts on both electricity rates and system revenue requirements. The CPVRR analysis therefore informs and furthers FPL's objective of minimizing the Company's projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or "RIM" methodology), which is a tangible benefit to customers.

Q. How many potential resource plans did the AURORA model evaluate for FPL's system?

A. After incorporating FPL's input parameters, AURORA evaluated hundreds of possible resource plans that met FPL's future resource needs using only generation or supply options. These resource plans included consideration of all potentially implementable generation resources, including solar, battery storage, and fossil options. The model identified utility-scale battery storage and solar resources as optimal additions based on their CPVRR relative to other resources and their ability to address input parameters specified for the model run.

Q. How did FPL review the AURORA outputs in light of the stochastic LOLP analysis findings?

A. FPL tested the resource additions identified by AURORA to determine the most cost-effective resources that could address FPL's reliability needs as identified through the stochastic LOLP analysis. This testing procedure was a necessary and additive component of the resource planning process, as the AURORA model identifies resource options on the basis of the Company's minimum reserve margin requirement, which is only analyzed at the system's summer and winter peaks (*i.e.*, two peak hours per year).

Q. What resource additions did FPL identify that most cost-effectively address the reliability needs identified through the stochastic LOLP analysis?

A. FPL's resource planning identified the following installations as the most cost-effective to meet FPL's resource needs in the 2026 through 2029 timeframe:

- 1,419.5 MW of battery storage and 894 MW_{AC} of solar in 2026;
- 819.5 MW of battery storage and 1,192 MW_{AC} of solar in 2027;
- 596 MW of battery storage and 1,490 MW_{AC} of solar in 2028; and
- 596 MW of battery storage and 1,788 MW_{AC} of solar in 2029.

These proposed additions represent a greater than 50% reduction in planned solar for 2026 and 2027 as compared to FPL's 2024 TYSP, in favor of the reliable firm capacity provided by utility-scale battery storage, which more than doubles relative to the battery storage additions identified for 2026 and 2027 in FPL's 2024 TYSP. Years 2028 and 2029 represent similar decelerations of solar deployment in favor of additional MW of battery storage capacity as compared to the 2024 TYSP.

Q. Is it your assessment that these are the optimal system additions for FPL in years 2026 through 2029?

A. Yes. These are the most cost-effective system additions to meet FPL's reliability needs identified through the stochastic LOLP analysis and ensure sufficient capacity and generation production for every hour of the year. Consistent with my CPVRR analyses, which are described in my testimony below, these system additions meet FPL's resource needs and are also projected to save customers several billions of dollars over the life of the assets.

Q. Could purchasing power as needed be a reliable solution to address the resource needs identified by FPL's LOLP modeling?

A. No. Having consulted with FPL's Energy Marketing and Trading business unit, purchasing power to address these needs would not be a viable solution. Purchasing power, either in the near- or long-term, would require that capacity be consistently available at the times FPL most requires it. However, the availability of power purchases would be extremely limited during any situation with higher-than-normal loads in Florida. Additionally, long-term power supply agreements often require power deliveries to be scheduled a day ahead or contain other scheduling limitations that would compromise FPL's ability to flexibly meet hour-to-hour supply needs. Further, the supply of wholesale power available in the Florida market is limited and may become increasingly more so as utilities in the Southeast continue to anticipate (and potentially recognize) significant load growth. Therefore, to rely on as-needed purchases during times of system constraint would jeopardize FPL's power supply availability, a circumstance that FPL must plan to avoid.

Q. Is it your assessment that the battery storage and solar additions you identified are prudent compared to adding natural gas-fired generation?

A. Yes. The addition of solar generation and battery storage is more cost-effective than constructing new natural gas generation. As demonstrated in my CPVRR analyses presented below, using natural gas-fired generation to address FPL's reliability needs would increase costs for FPL customers by billions of dollars compared to the utility-scale battery storage and solar resources I identified.

Q. Aside from being more costly, are there other reasons why adding natural gas-fired generation is not a suitable substitute for the solar and battery storage additions you identified?

A. Yes. The potential to construct and bring natural gas generation to operation in the near term is severely limited. Combustion turbines ("CTs") cannot be quickly implemented and require multiple years to construct and reach operation. Moreover, gas supply available to FPL is limited, and the additional infrastructure required to increase the availability of gas supply takes time and cost to develop. This makes CTs unsuitable for addressing reliability needs in the near term.

Additionally, the components needed to construct new CTs have become increasingly difficult to timely obtain. Overseas demand and recent supply-chain issues have pushed the earliest realistic in-service date for CTs to late 2029 or early 2030. These in-service dates would lead to CTs being unable to meet FPL's resource needs in the 2026-2029 timeframe.

B. *FPL's Planned Resource Additions (2026)*

Q. Please provide an overview of FPL's current battery storage and solar portfolio.

A. At this time, FPL has 469 MW of utility-scale, grid connected battery storage installed on its system at three separate locations and is currently constructing 522 MW of new battery storage adjacent to seven existing solar energy centers. As for FPL's solar fleet, FPL had a total of approximately 7,038 MW_{AC} (nameplate) of utility-owned solar generation as of the end of 2024, all of which are PV facilities. FPL also has 894

MW_{AC} of solar generation in various stages of development that are expected to enter service in 2025, including those that are a part of the solar base rate adjustments approved in FPL's last base rate proceeding. These solar projects are spread throughout FPL's system, providing energy derived from cost-effective renewable solar resources throughout FPL's service area.

Q. How has the addition of the solar facilities you mentioned contributed to FPL's system?

A. Solar contributes to FPL's system, and has benefitted FPL's customers, in the following ways:

1. Solar provides a portion of its nameplate capacity as firm capacity during the times of FPL's system peaks.
2. Solar provides fuel-free (and emission-free) energy that reduces the fuel portion of customer bills. From 2021 through 2024, FPL customers have saved approximately $942 million in avoided fuel expenses from solar installed on FPL's system.
3. Since 2023, solar production from new sites has also been eligible for a Production Tax Credit that reduces the cost of solar and is passed on directly to FPL's customers.

All three of these factors have led to solar being an economic resource option for FPL and continue to drive the cost-effectiveness of solar in FPL's resource plans.

Q. What is FPL's resource need for 2026?

A. As identified in the stochastic LOLP analysis, FPL needs 1,663 MW of additional firm capacity to meet its LOLP requirement in 2027. To meet this need FPL must add firm capacity in 2026 so that it is positioned to meet the identified 2027 reliability need.

Q. What resources does FPL plan to add in 2026 to address this need?

A. FPL is proposing to add 1,419.5 MW of battery storage and 12 74.5 MW solar sites (894 MW) in 2026. Installation of these system additions is supported by FPL's resource planning analysis, undertaken in accordance with the process I described earlier. FPL witness Oliver provides additional details concerning each of these proposed solar additions, as well as those in 2027.

Q. How do these additions address the need identified in the stochastic LOLP analysis?

A. In short, the MWs provided by the 2026 additions allow FPL to address the reliability need identified through the stochastic LOLP analysis by 2027, while also maintaining FPL's adherence to all other reliability criteria. Adding these resources, along with additional resources in the first half of 2027, will bring FPL's projected LOLP under the 0.1 days-per-year standard for 2027.

The 2026 additions also provide two specific system needs identified through the stochastic LOLP analysis: (1) the additional need for stable, dispatchable capacity; and (2) the need for FPL to maintain sufficient generation to meet FPL's increasingly higher load. The proposed battery storage additions will have the ability to quickly discharge energy to FPL's system to address hourly operational requirements, which enhances the reliability of FPL's system. The facilities will also provide year-round capacity to promote system reliability regardless of the time of day or the weather conditions and enable low-cost energy to be stored and delivered when needed. In that way, the storage additions will serve as key resources that allow FPL to increase system reliability and flexibility by cost-effectively addressing times of peak energy consumption, which ordinarily occur in the evenings.

The solar additions, combined with the battery storage, allow FPL to maintain sufficient generation resources to reliably meet the needs of an increasing customer base and higher loads. In addition to FPL's peak demand growing, FPL's net energy load (*i.e.*, the amount of energy on the system throughout the year) is also growing. FPL's proposed solar additions help meet this increased energy need with energy that is produced cost-effectively and uses no fuel, thereby putting downward pressure on customer rates over the long-term.

The 2026 additions can also be sited, constructed, and operational within a much shorter timeframe than other generation resources, such as CTs as I discussed above.

Q. Are there additional considerations that support the inclusion of 1,419.5 MW of battery storage in 2026?

A. Yes. The continued deployment of low-cost solar generation, which generates electricity during daytime hours, is complemented by storage in order to continue to push low-cost power to the grid when needed. With FPL's typical net system peak (after accounting for solar generation) occurring in the evening time, storage capacity enables FPL to dispatch lower-cost electricity during these net peak times.

Also, FPL's combined-cycle fleet most often undergoes maintenance during the shoulder months, which have been susceptible to high load conditions. The stable capacity provided by battery storage helps to address higher loads and unexpected events, which in turn promotes system reliability.

Battery storage also provides variable cost savings via energy arbitrage – *i.e.*, charging when energy is the cheapest and discharging to avoid more expensive generation. Energy arbitrage becomes even more pronounced when a system has large amounts of solar, as is the case with FPL. Solar drives down the price of energy during the day, and batteries can discharge in the early evening to avoid more expensive generation starting or ramping up, increasing generation resource cost-effectiveness to the benefit of customers.

Q. Is the addition of the 2026 battery storage and solar facilities cost-effective?

A. Yes, as detailed in my CPVRR analysis below and attached to my testimony in Exhibit AWW-5, these additions, along with the proposed 2027 additions, are projected to save customers nearly $2 billion over the lives of the assets.

C. *FPL's Planned Resource Additions (2027)*

Q. What is FPL's resource need for 2027?

A. As identified in the stochastic LOLP analysis, FPL's total firm MW requirement increases by 626 MW from 2027 to 2028, and it must make additions in the beginning half of 2027 to address the identified 273 MW need for 2027 shown in Exhibit AWW-1.

Q. Please detail FPL's proposed resource additions in 2027 to address this need.

A. FPL's analysis supports the construction of 16 74.5 MW solar sites (1,192 MW) and another 819.5 MW of battery storage throughout 2027. Adding these resources (along with the 2026 additions) will allow FPL to meet its 0.1 days per year LOLP criterion throughout 2027.

Q. How do the 2027 additions address the need identified in the stochastic LOLP analysis?

A. These additions address the resource need identified for 2027 in the same manner I described for the 2026 additions above; that is, by providing the stable, dispatchable capacity and energy needed generation to meet FPL's identified system need. FPL's addition of 1,192 MW of new solar generation and 819.5 MW of battery storage in 2027 allow FPL to maintain a 0.1 days-per-year LOLP throughout 2027. Additionally, even with the 2027 additions, FPL must add additional firm capacity in the first half of 2028 to address a 19 MW shortfall identified for 2028.

Q. Are FPL's 2026 and 2027 resource additions supported by a CPVRR analysis?

A. Yes. FPL tested the cost-effectiveness of its 2026 and 2027 solar and battery storage additions to ensure they are the most cost-effective options to address the Company's identified reliability needs.

Q. What was the result of that CPVRR analysis?

A. The combination of FPL's planned 2026 and 2027 solar and battery storage additions result in $1,942 million CPVRR savings for FPL's customers, as compared to an alternative plan that excludes the additions. This analysis demonstrates that the facilities provide substantial savings for FPL's customers while addressing FPL's identified reliability needs. Exhibit AWW-5 provides the results of the CPVRR analysis.

D. *FPL's 2028 and 2029 Resource Needs*

Q. What is FPL's resource need for 2028 and 2029?

A. As identified in the stochastic LOLP analysis, FPL's need for additional firm capacity continues to increase in years 2028 through 2030. Between 2028 and 2029 FPL's total reliability need increases from 32,948 MW to 33,544 MW, an increase of 596 MW. Between 2029 and 2030, FPL's total reliability need increases from 33,544 MW to 34,102 MW, an increase of 558 MW. The stochastic LOLP analysis shows that without added resources in 2028 and 2029 to address this increasing growth, FPL will fall short of its 0.1 days-per-year LOLP standard.

Q. Has FPL identified which resources best address these needs?

A. Yes. Based on FPL's analysis the most cost-effective resources to meet those needs are 1,490 MW of solar in 2028 and 1,788 MW of solar in 2029, as well as 596 MW of battery storage in each of those years. These additions will allow FPL to maintain its 0.1 LOLP standard in both 2028 and 2029. As with 2027, FPL must add resources earlier in 2028 and 2029 to address MW shortfalls in those years of 19 MW and 104 MW, respectively. Additionally, as shown in Exhibit AWW-1, even with the proposed 2028 and 2029 additions, FPL will still have a reliability need in 2030 and beyond, which will have to be addressed in order to maintain an LOLP of 0.1 days-per-year.

Q. What is driving FPL's projected system needs in 2028 and 2029, and how do the identified resources meet those needs?

A. FPL's system is projected to continue growing throughout the 2028-2029 time period, such that energy from new cost-effective solar will be needed while capacity from battery storage will ensure that power can be reliably delivered to customers every hour of the year. As FPL's system continues to grow and leverage cost-effective solar generation, the requirement to maintain sufficient and readily dispatchable generation becomes increasingly necessary, as shown in the stochastic LOLP analysis.

As with FPL's 2026 and 2027 additions, the resources identified for 2028 and 2029 are projected to address the capacity need identified in the stochastic LOLP analysis and ensure that FPL's other reliability criteria are met. Additionally, these resources can be constructed and operational in time to meet the identified needs.

Q. Are the Company's identified resource additions in 2028 and 2029 forecasted to be cost-effective?

A. Yes. Not only do the 2028 and 2029 additions contribute to FPL's ability to provide reliable power to customers over every hour of the year, they are also cost-effective compared to adding gas-fired CTs.

Q. What are the projected CPVRR savings of a resource plan with the 2028 and 2029 additions as compared to a resource plan without these additions?

A. As demonstrated in Exhibit AWW-6, the projected CPVRR benefit to FPL's customers of adding the 2028 and 2029 additions compared to a plan that only adds CTs to address peak reserve margin needs is $2,213 million.

Q. Is FPL requesting approval for cost recovery associated with the 2028 and 2029 additions you have identified?

No, not in this proceeding. My testimony provides FPL's projected needs based on FPL's current resource planning. As discussed by FPL witnesses Bores, Laney, and Oliver, FPL's four-year plan proposes a Solar and Battery Base Rate Adjustment mechanism pursuant to which FPL would seek recovery for solar and battery storage facilities installed in 2028 and 2029 upon a showing of a resource or economic need based on updated information.

III. UPDATE TO COST OF SERVICE METHODOLOGY

Q. What production cost-of-service methodology is FPL proposing to use in this proceeding?

A. As detailed in the testimony of FPL witness DuBose, FPL is proposing to use a 12 CP and 25% allocation method for production plant to better align cost allocations among customer classes with changes to FPL's portfolio of generation resources.

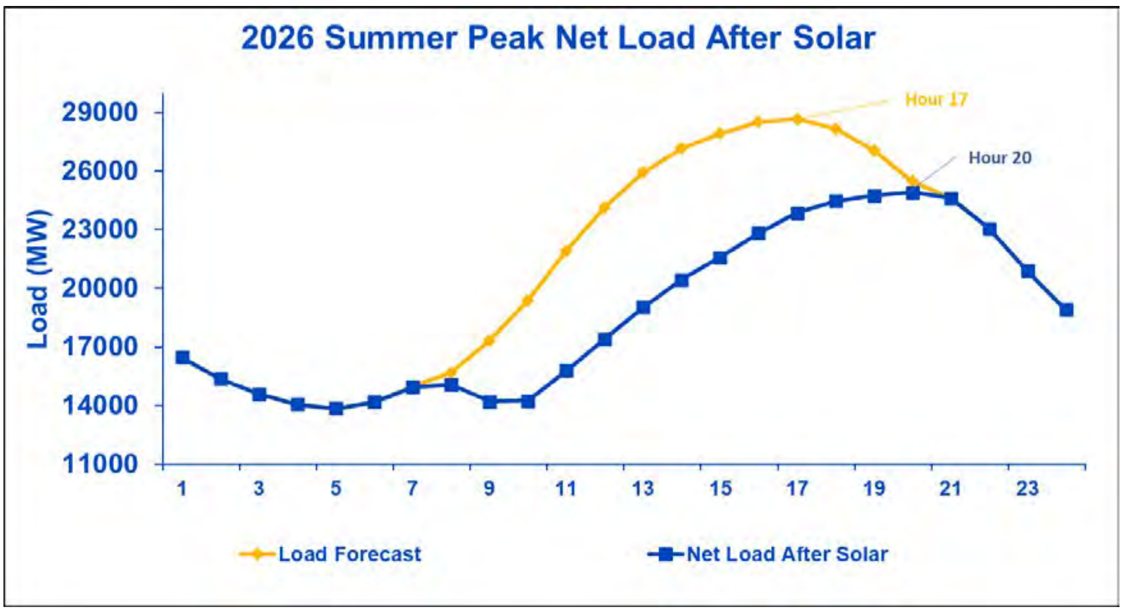
Q. What are the changes to FPL's generation portfolio that support the revised cost of service methodology?

A. As I detailed earlier in my testimony, FPL has installed a significant amount of cost-effective solar generation and plans to continue expanding its development of solar resources. This expansion is pushing FPL's critical time of peak to later in the evening, which is when incremental dispatchable generation is needed.

With FPL's implementation of more solar generation, FPL has begun using a "net peak load" methodology to assign firm capacity values to solar added to its system. This methodology takes the hourly shape of FPL's load forecast, then subtracts the projected hourly solar generation from the load. The resulting shape shows FPL's "net peak load" and represents the load that incremental generation additions must meet. As discussed previously, as more solar generation is added to FPL's system, the time of the net peak shifts further into the evening – therefore, incremental solar additions have an incrementally lower firm capacity value as their generation declines in the peak evening hours. Despite this decline in firm capacity value for solar, solar generation continues to be the most cost-effective resource for FPL's system, based on the energy needs that it serves throughout the day.

As shown in Figure 1 below, FPL's system peak in 2026, excluding solar generation, occurs at hour-ending 5:00 p.m. in the summer. However, after accounting for the projected output from FPL's incremental solar additions through 2026, FPL's net load peak shifts to hour-ending 8:00 p.m.

FIGURE 1



These changes in FPL's system move the effective system peak later into the evening, and the types of customers and customer activities that cause the need for incremental generation during these times are different. These changing system dynamics and the changing times of FPL's net load peak support the Company's change in production cost-of-service methodology, as detailed by FPL witness DuBose.

IV. LARGE LOAD CONTRACT SERVICE

Q. What tariff changes is FPL proposing to address the impacts of future large load customers?

A. As explained in the testimony of FPL witness Cohen, FPL is proposing new rate schedules for future customers with a projected new or incremental load of 25 MW or more and a projected load factor of 85% or more. Those rate schedules, LLCS-1 and Large Load Contract Service-2 ("LLCS-2"), are designed to proactively address the potential scenario that future customers of this size request service within the FPL service area and, if so, to ensure that the general body of customers is protected from the higher costs to serve such large load customers. In order to serve a customer of this magnitude, FPL would need to make significant investments in new incremental generation capacity that, but for the customer's request for service, would not otherwise be incurred or needed to serve the general body of customers.

Q. Why is the maximum of 3 GW of demand appropriate for LLCS-1?

A. As explained by FPL witness Cohen, rate schedule LLCS-1 will be available to serve a combined total of 3 GW of demand in three specific regions of the Company's service area. These regions were selected based on their proximity to FPL's transmission facilities and areas suitable for the incremental generation capacity necessary to serve up to a combined total load of 3 GW. In these regions FPL would be able to accommodate up to approximately 1 GW of new demand without significant network upgrades – thereby minimizing overall costs incurred – while still meeting all of FPL's reliability criteria. Additionally, the 3 GW maximum for rate schedule LLCS-1 is appropriate because it corresponds to the amount of generation that FPL forecasts it can reasonably and safely ramp up and deploy on its system starting in 2028 to serve up to 1 GW of new demand in each of the selected regions. The 3 GW maximum demand for schedule LLCS-1 therefore mitigates the potential for reliability issues and costly new system investment, and better ensures that FPL can safely dispatch system resources efficiently to meet the high load factor demand of these potential new large load customers.

V. INCENTIVE PAYMENT LEVELS FOR CDR & CILC

Q. Please describe the CDR and CILC programs.

A. The CDR and CILC programs are FPL's largest DSM programs for commercial and industrial customers. Voluntary participants in these programs agree to allow FPL to remotely lower a portion of the participant's served electric load as needed (for example, during a period of high electrical demand on FPL's system) in exchange for the participant receiving a reduction in their monthly bill.

The two programs have a combined demand reduction capability of slightly more than 900 MW[1]. The CDR program is open to new participants. The CILC program was officially closed to new participants in the year 2000 and was essentially replaced by the CDR program, which offers a similar load management program to commercial and industrial customers.

[1] This value is the maximum summer peak value, calculated at the generator.

Q. What are the current incentive payment levels for the two programs?

A. The incentive payments are administered differently for each program. For the CDR program, the incentive is administered as a $/kW credit on the monthly bill. The current CDR program monthly incentive is $8.76/kW. For the CILC program, the incentive is administered as a percentage reduction of the base bill as discussed in the testimony of FPL witness Cohen.

Q. How were the current incentive payment levels of the two programs set?

A. The current incentive payment levels were set pursuant to FPL's 2021 base rate settlement agreement approved by Order No. PSC-2021-0446-S-EI. Paragraph 4(e) of that agreement set incentive payments for the CDR and CILC programs at the then-current level until, at least, "the effective date of new FPL base rates implemented pursuant to a general base rate proceeding." The Commission affirmed that a general base rate proceeding is the appropriate proceeding for setting incentive payments for these programs for FPL with the Commission's approval of stipulations in Order No. PSC-2024-0505-FOF-EG.

Q. How does the current CDR rate compare with the rate that was in effect when most participants joined the program?

A. Approximately 75% of the existing CDR participants joined the program during 2000 to 2012. During this time period, the monthly incentive was initially $4.75/kW then decreased to $4.68/kW, representing just over 50% of its current amount.

Q. Is FPL proposing to change the monthly incentive payments for both programs in this proceeding?

A. Yes. FPL is proposing to change the incentives to align them with the value they provide to customers. My testimony discusses the proposed changes in incentive payments in terms of a $/kW payment format. The CILC program's incentive payment is a percentage reduction of the base bill. FPL witness Cohen discusses how rates are designed for CILC customers, and those rates are shown in Exhibit TCC-6.

Q. How large a factor are the incentive payments in relation to the overall costs of the programs?

A. The programs have three cost components: (i) administrative costs, (ii) unrecovered revenue requirements, and (iii) monthly incentive payments. Using the CDR program as an example, the monthly incentive payments account for approximately 99% of the projected total CPVRR cost of the CDR program. Consequently, the monthly incentive payment is the primary "driver" of program costs.

Q. How does FPL evaluate the economic value of the CDR and CILC programs?

A. FPL analyzes the cost-effectiveness of each of its DSM programs, including the CDR and CILC programs, using three cost-effectiveness screening tests: (i) the RIM test, (ii) the Total Resource Cost ("TRC") test, and (iii) the Participant test.

For programs such as CDR, the RIM test is the cost-effectiveness test used to set an appropriate incentive level. The TRC test does not incorporate incentives into its calculation of costs, and therefore does not change as the value of incentive payments change. The Participant test measures the benefit to the participant against any incremental costs the participant in a program incurs. For CDR, the participant does not incur any direct incremental costs to participate, resulting in an infinite cost-benefit ratio. For these reasons, FPL relies on the RIM test to analyze the appropriate incentive level for CDR in terms of economic value.

Q. How does FPL determine the full value of the CDR and CILC programs?

A. To make this determination, FPL evaluates the economics of two comparative resource plans developed using the AURORA optimization model. One resource plan, the "With Programs" plan, assumes the inclusion of all of the approximately 900 MW of demand reduction capability from existing CDR and CILC participants and the approximately 6 MW per year of projected new CDR participants. However, for purposes of the analysis, the projected monthly incentive payments for both existing and new participants are zeroed out. As a result, the "With Programs" resource plan accounts for all of the demand reduction benefits of the CDR and CILC programs but assumes no incentive payment costs.

The second resource plan, the "Without Programs" plan, assumes that all the existing CDR and CILC MW, all projected new CDR sign-ups, and all incentive payments for both programs are removed from the resource plan starting in January 2026.[2] The AURORA model then selected the most cost-effective generation resources to replace the loss of 900+ MW of demand reduction capability.

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[2] Note that the use of the January 2026 "exit" date assumption means all existing participants in the CDR and CILC programs would exit the programs with less than one year's notice (which ignores the 5-year exit notice terms for both programs). Because of this assumed sudden loss of 900+ MW of demand reduction capability, replacement capacity needs to be added relatively quickly. As a result, the January 2026 exit assumption maximizes the projected value of the two programs for purposes of this analysis.

The projected CPVRR costs of the two resource plans were then compared. The projected CPVRR cost of the Without Programs resource plan, $100,390 million, is higher than the projected CPVRR cost of the With Programs resource plan, $99,322 million, because the Without Programs resource plan must add new resources to make up for the loss of the 900+ MW of demand reduction capability offered by the CDR and CILC programs. The two resource plans, and the projected CPVRR costs for each plan, are presented in Exhibit AWW-7.

The $1,069 million ($100,390 - $99,322 = $1,069) CPVRR differential represents the projected benefits of the CDR and CILC programs through 2071. It also represents – after accounting for the administrative costs of the CDR and CILC programs – the amount of CPVRR cost that can be paid in the form of monthly incentive payments to CDR and CILC participants in the With Programs resource plan before both resource plans will have an identical CPVRR cost (assuming that there will be no future changes to the current projections of CDR and CILC benefits or program administrative costs).

Q. What other considerations were taken into account when developing the proposed new monthly incentive payment for the two programs?

A. Three other considerations were taken into account in establishing the proposed incentive payment levels for the programs. The first consideration for any DSM program, including these two programs, is that the maximum incentive level that should be considered is one that results in program costs exactly equaling program benefits (*i.e.*, a RIM benefit-to-cost ratio of 1.00). Such a result means that program participants will benefit from the program and that the utility's general body of customers should be indifferent regarding whether the program is offered because electric rates are unchanged compared to what they would be if the DSM program had not been offered and the best generation alternative had been chosen instead.

The second consideration is that, all else equal, it is preferable for a DSM program's RIM benefit-to-cost ratio to be greater than 1.00. In such a case, all customers benefit from the DSM program, not just the program participants. This consideration recognizes that paying the maximum incentive for a DSM program does not maximize the benefit to the general body of customers – it merely ensures that the general body is indifferent.

The third consideration is how the demand response is credited in terms of capacity in FPL's system. Based on the stochastic LOLP analysis, demand response is limited to a certain percentage of its capacity, which, over time, degrades its potential to serve FPL's increasing load. Therefore, the further beyond 1.00 the RIM ratio is, the more assurance there is that the credit given to CDR customers does not outweigh its benefits to the general body of customers.

Q. Taking these considerations into account, how did FPL determine the appropriate incentive level for these programs?

A. First, cost-effectiveness calculations were performed for the current CDR monthly incentive level of $8.76/kW (Scenario 1). These calculations are presented in Exhibit AWW-8. The left-hand side of Exhibit AWW-8 presents seven assumptions used in the calculations. Assumption (1) is the CPVRR difference between the With Programs resource plan and the Without Programs resource plan that appears in Exhibit AWW-7, which is $1,069 million. Assumption (2) is the projected CPVRR administrative cost of the combined CDR and CILC programs, which equates to $10 million. Assumption (3) is the current monthly incentive level for CDR of $8.76/kW. Assumptions (4) through (7) present other inputs used in calculations.

The right-hand side of Exhibit AWW-8 presents a table that shows the results of calculations for two scenarios. In Scenario 1, the projected RIM benefit-to-cost ratio for the 900+ MW of CDR and CILC with the current monthly incentive level of $8.76/kW is shown: 1.06. This result shows that the program and its current incentive level is beneficial for participants but, with a RIM ratio of near 1.00, leaves the general body near the point at which they are indifferent to the program.

For that reason, and based on the three evaluative considerations discussed above, FPL determined that it was appropriate to lower the monthly CDR incentive level to $6.22/kW. Scenario 2 in Exhibit AWW-8 shows the same calculations for the programs with the revised monthly incentive level, as well as the resulting RIM benefit-to-cost ratio of 1.49. This higher benefit-to-cost ratio provides a reasonable level of assurance that the programs will remain cost-effective for all customers for the expected 4-to-5-year period until the incentive levels are next reviewed. This value also ensures that CDR is still beneficial to participants and does not burden non-participants with higher program costs than are required for maintenance of the program. Moreover, as stated in the testimony of FPL witness Cohen, the annual savings associated with the reduction in the credit for CILC and CDR customers is approximately $22 million in 2026 and 2027.

Q. How does the proposed monthly incentive level compare to the incentive level that existed at the time most of the CDR participants joined the program?

A. As I referenced above, approximately 75% of the existing CDR participants joined the program during 2000 to 2012, when the monthly incentive was initially $4.75/kW then decreased to $4.68/kW. The proposed new CDR monthly incentive level of $6.22/kW is nearly 31% higher than the incentive level that was in place when the majority of CDR participants joined the program.

Therefore, this proposed new incentive level will be sufficient to help ensure the cost-effectiveness of the CDR and CILC programs for a 4- to 5-year period, achieve future CDR program participation needed to meet FPL's approved DSM Goals, retain existing CDR and CILC participants, and ensure that non-participants are not bearing unnecessary program costs.

Q. Does this conclude your direct testimony?

A. Yes.

Florida Power & Light
Resource Adequacy Study

February 21, 2025

Energy+Environmental Economics

Overview

+ **FPL asked E3 to perform a loss-of-load study of the FPL system using E3's Renewable Energy Capacity Planning (RECAP) model to answer three key questions:**
  1. What is the FPL system's achieved reliability during 2027-2030 and 2035?
  2. What is the contribution of each resource type to maintaining resource adequacy?
  3. What is the nature, timing and duration of simulated loss-of-load events on the FPL system?
+ **This report summarizes the results of that study**

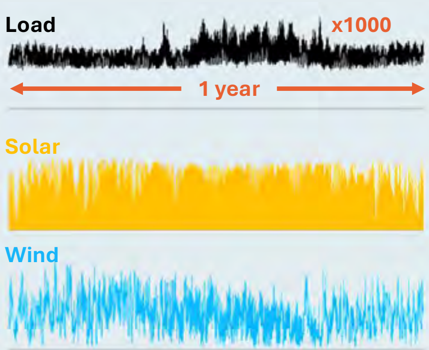
RECAP Model Overview

Energy+Environmental Economics

Overview of best practices in resource adequacy analysis

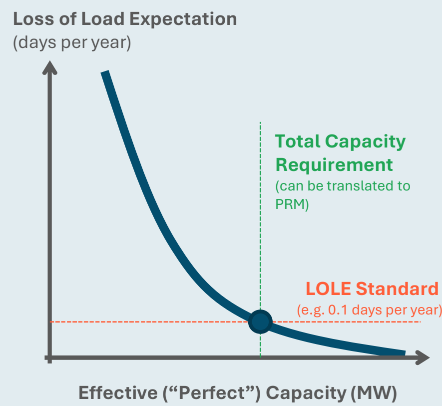
Step 1: Develop a representation of the loads and resources of an electric system in a loss of load probability (LOLP) model

LOLP modeling allows a utility to evaluate resource adequacy across all hours of the year under a broad range of weather conditions, producing statistical measures of the risk of loss of load



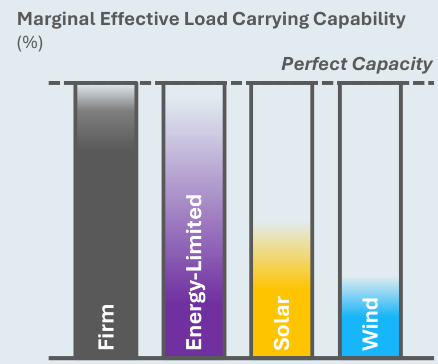
Step 2: Identify the amount of perfect capacity needed to achieve the desired level of reliability

Factors that impact the amount of perfect capacity needed include load & weather variability, operating reserve needs



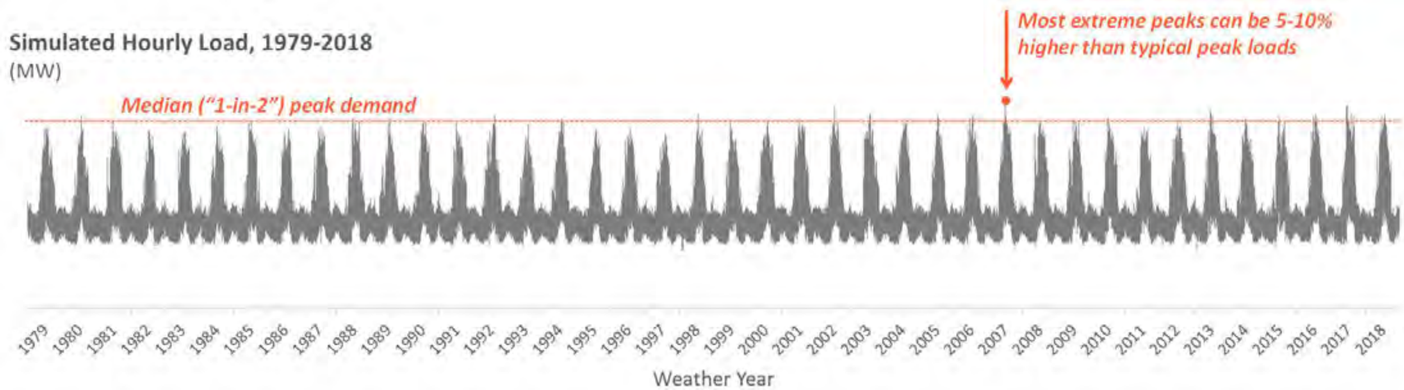
Step 3: Calculate capacity contributions of different resources using effective load carrying capability (ELCC)

ELCC measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraints



Loss-of-load probability (LOLP) modeling is the foundation for understanding resource adequacy needs

- **LOLP modeling can be thought of as an organized way to analyze the potential for extreme weather and other events to cause a supply shortfall**
- **LOLP captures factors that matter for reliability such as:**
  - High loads due to extreme weather
  - Correlations between load and renewable conditions
  - Energy and capacity limitations
  - Dispatch behavior of energy-limited resources such as energy storage and demand response



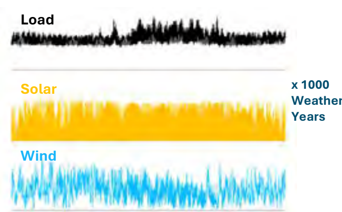
RECAP – Loss-of-Load-Probability Model

A loss-of-load-probability model is designed to study the reliability dynamics of an electric system

+ **LOLP model simulates the operations of the electricity system under hundreds of scenarios to capture different conditions, including:**
  - load variability,
  - weather variability,
  - renewable output variable, and
  - forced outage events
+ **Key LOLP Modeling outputs:**
  - System reliability
  - Target Planning Reserve Margin
  - Capacity Shortfall
  - Capacity Value of Resources

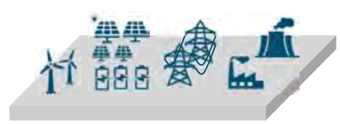
Temperature and Load Artificial Neural Network Simulation

Capturing hourly load conditions under mild and extreme historical weather



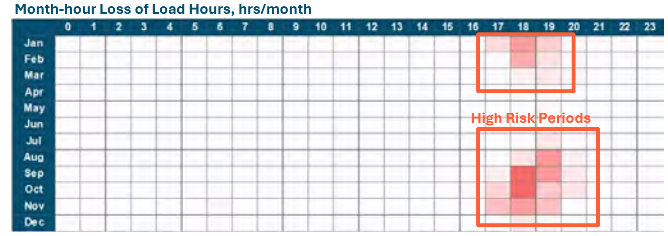
Operational Module

Dispatching resources based on outage characteristics, weather dependency, state of charge availability, and demand-side management



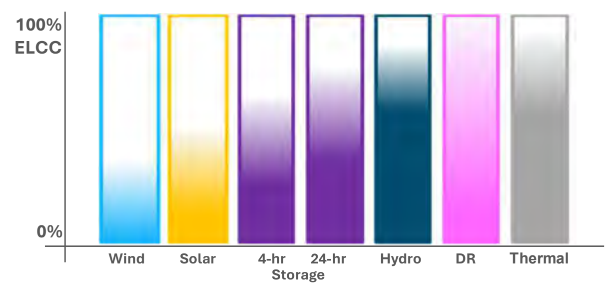
System Reliability: simulates the operations of the electricity system under thousands of scenarios to capture different conditions

Month-hour Loss of Load Hours, hrs/month



Resource Capacity Value: measures resource's ability to contribute to reliability under a marginal or average methodology

Illustrative ELCC Values Across Technologies



RECAP Inputs and Outputs

Inputs

Load
- *Hourly load for many weather years*

Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*

Outputs

LOLE
- *Loss of load expectation*
- *days/yr of total expected lost load*

LOLH
- *Loss of load hours*
- *hrs/yr of total expected lost load*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLE, ALOLP, or EUE)*

RECAP Workflow

Weather-matched load, wind and solar

Energy-limited resources dispatched time-sequentially

System Demand
(net of EE) simulated hourly across a broad range of weather conditions

Variable Resources
(including BTM PV) simulated with weather-matched hourly profiles

Firm Resources
simulated based on rated capacity and outage rates

Hydroelectric Resources
dispatched based on monthly capacity & energy limits

Storage Resources
dispatched according to limits on duration and round-trip losses

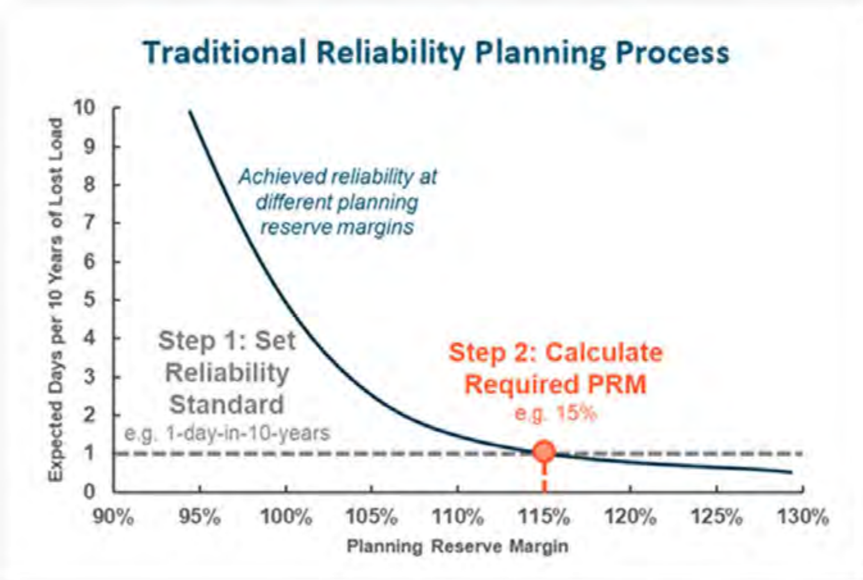
DR Programs
dispatched subject to limits on number of calls & duration

Unserved Energy
identified based on any unmet demand

Each simulation analyzes conditions across hundreds to thousands of possible years using a Monte Carlo approach, where each year captures a different combination of underlying weather, load, wind & solar profiles; outage patterns; and energy-limited resource dispatch

This study calculates FPL's Total Resource Need (TRN) and Target Planning Reserve Margin (Target PRM) that achieves a 0.1 LOLE standard

- **Total Resource Need is the quantity of effective capacity needed to meet a defined reliability standard**
  - Defined for this study as "1 day in 10 years" or Loss-of-Load Expectation ("LOLE") of 0.1 days/yr.
- **PRM is measured as the quantity of capacity needed above the median year peak load to meet the LOLE standard**
  - Calculated as (TRN – Median Peak)/Median Peak
  - Serves as a simple and intuitive metric that can be utilized broadly in power system planning
  - Considers load and resource conditions during *<u>all hours of the year</u>*



Resource adequacy challenges are evolving, necessitating updates to historical analytical methods

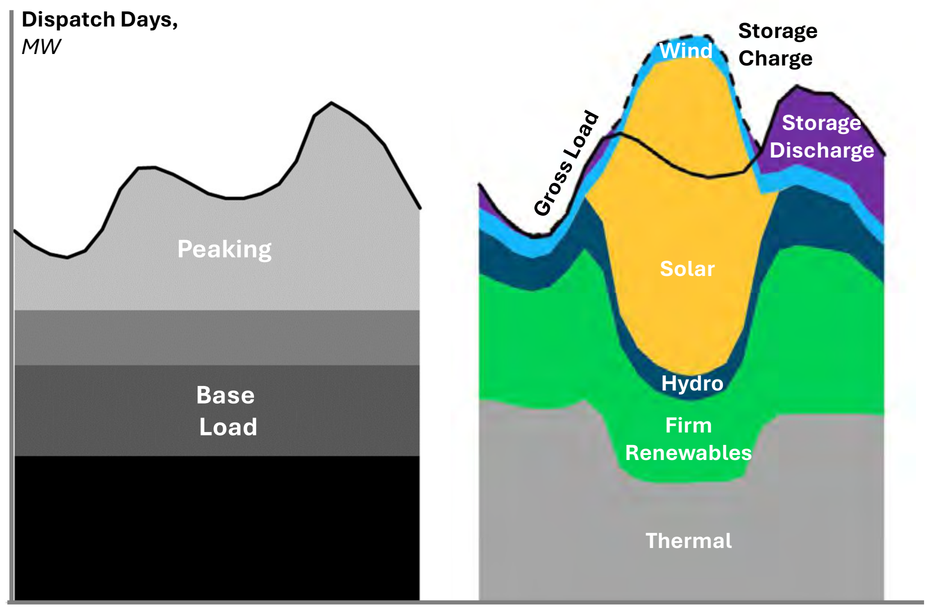
- **Traditional resource adequacy planning relies on dispatchable resources to meet gross peak demand**
- **As renewable penetration grows, planning to meet net peak demand becomes the pivotal challenge**
- **Capturing thermal fleet unavailability is increasingly important as its capacity value may be affected by correlated outages**

Traditional Systems

Are there enough thermal resources to meet gross peak demand?

Today and Future Systems

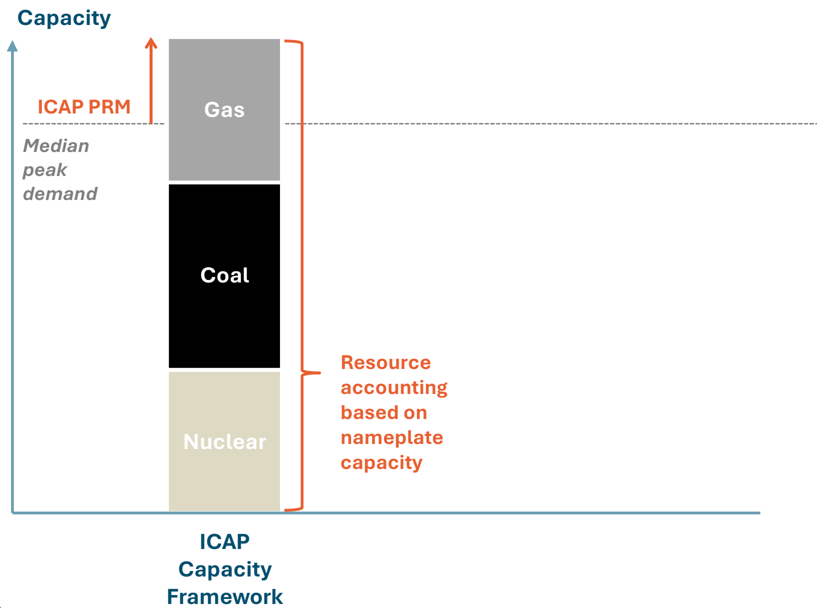
How does the portfolio of variable, energy-limited, ***and*** *dispatchable resources combine to contribute to reliability?*



Traditionally, resource accreditation was simple with conventional "firm" generating resources

- **PRM defined based on Installed Capacity method (ICAP)**
  - Covers annual peak load variation, operating reserve requirements, and thermal resource forced outages
- **Individual resources accredited based on nameplate capacity**
  - Small differences in forced outage rates
  - No interactions among resources
  - Forced outages also incorporated through performance penalties

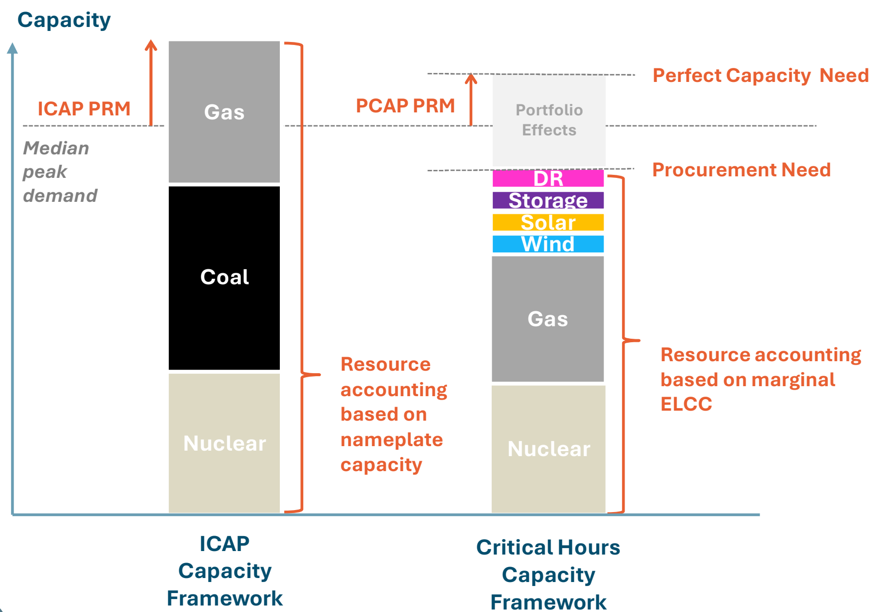
$$Installed\ Capacity = \sum_{i=1}^{n} G_i$$



ELCC approach adapts the PRM framework for a more diverse resource mix and calculates each resource type's contribution to the Total Resource Need

- **PRM defined based on need for Equivalent Perfect Capacity (PCAP)**
  - Covers annual peak load variation and operating reserves only; forced outages addressed in resource accreditation
- **Individual resources accredited based on ELCC**
  - Large differences in availability during key hours
  - Significant interactions among resources
  - ELCC values are dynamic based on resource portfolio

$$Portfolio\ ELCC = f(G_1, G_2, \ldots, G_n)$$



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Measuring ELCC of a portfolio and individual resources

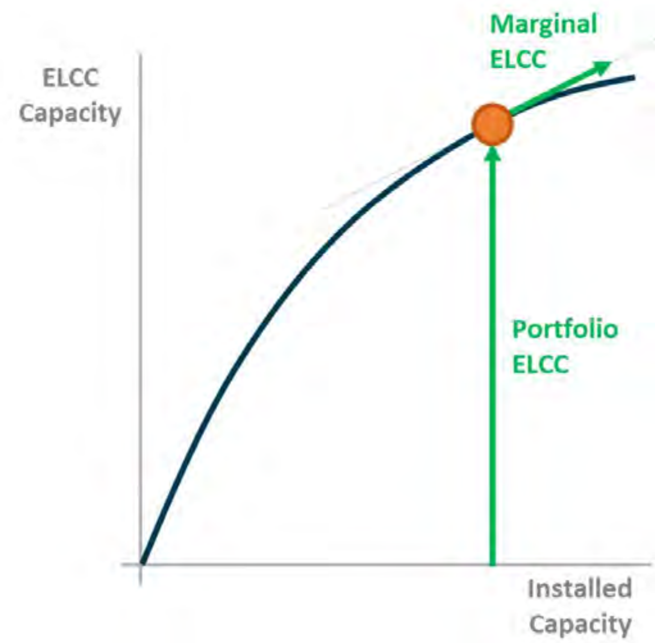
+ **ELCC is a function of the portfolio of resources**
  - The function is a surface in multiple dimensions
  - The Portfolio ELCC is the height of the surface at the point representing the total portfolio

$$Portfolio\ ELCC = f(G_1, G_2, \ldots, \ G_n)\ (MW)$$

  - The Marginal ELCC of any individual resource is the gradient (or slope) of the surface along a single dimension – mathematically, the partial derivative of the surface with respect to that resource

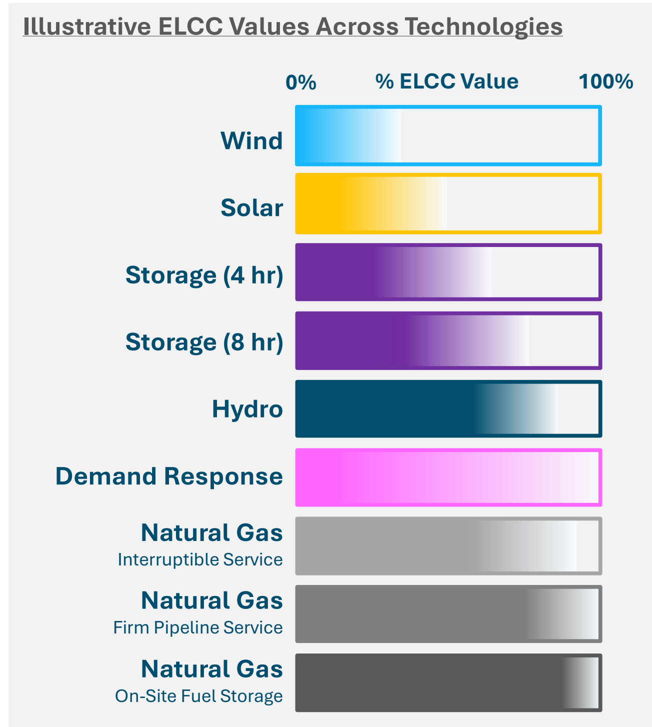
$$Marginal\ ELCC_{G_1} = \frac{\partial f}{\partial G_1}(G_1, , G_2, \ \ldots\ G_n)\ (\%)$$

+ **The functional form of the surface is unknowable**
  - Marginal ELCC calculations give us measurements of the contours of the surface at specific points
  - It is impractical to map out the entire surface

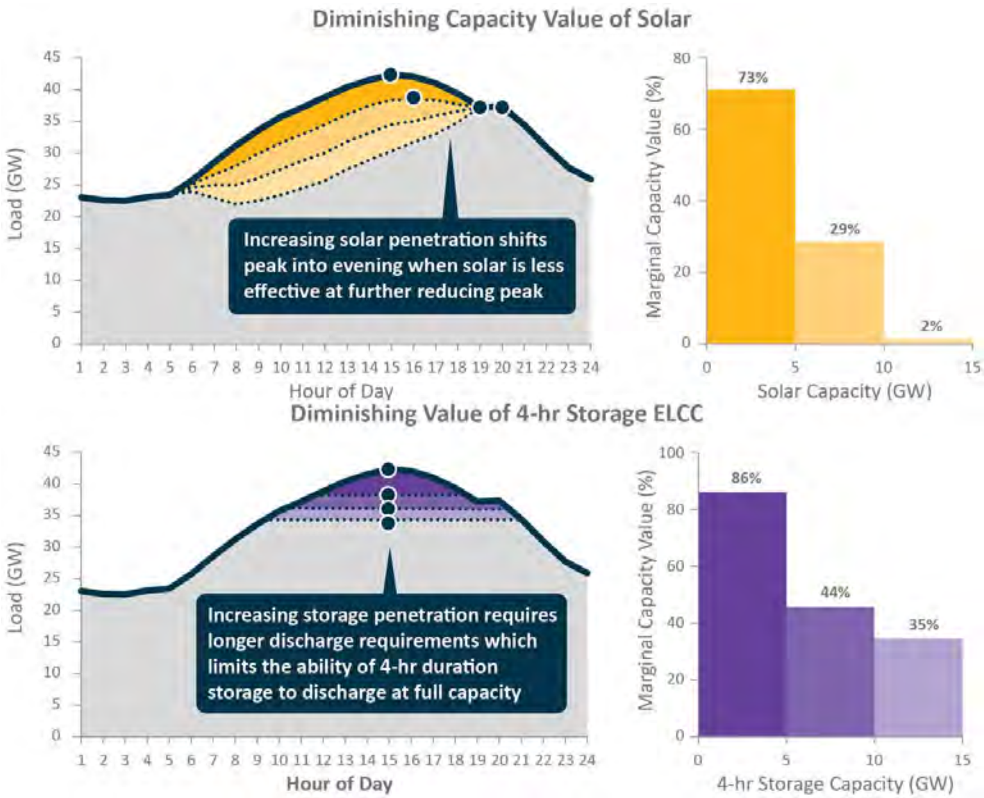


E3 used a marginal ELCC methodology to calculate each resource type's incremental contribution to system resource adequacy

- **No resource is "perfect": ELCC measures all resources against equivalent perfect capacity**
  - Demand response also accredited using ELCC based on modeled performance during critical hours
- **Accounts for all factors that can limit availability:**
  - Hourly variability in output
  - Duration and/or use limitations
  - Temperature-related derates
  - Temperature-related forced outage rates
  - Energy availability
  - Correlated outage risk
- **Uses Perfect Capacity (PCAP) accounting as opposed to ICAP or UCAP**



RECAP's ELCC calculations capture diminishing capacity contribution of variable and dispatch-limited resources at higher penetrations



Solar and other **variable resources** exhibit declining value due to variability of production profiles

Storage and other **energy-limited resources** (e.g. DR) exhibit declining value due to limited ability to generate over sustained periods

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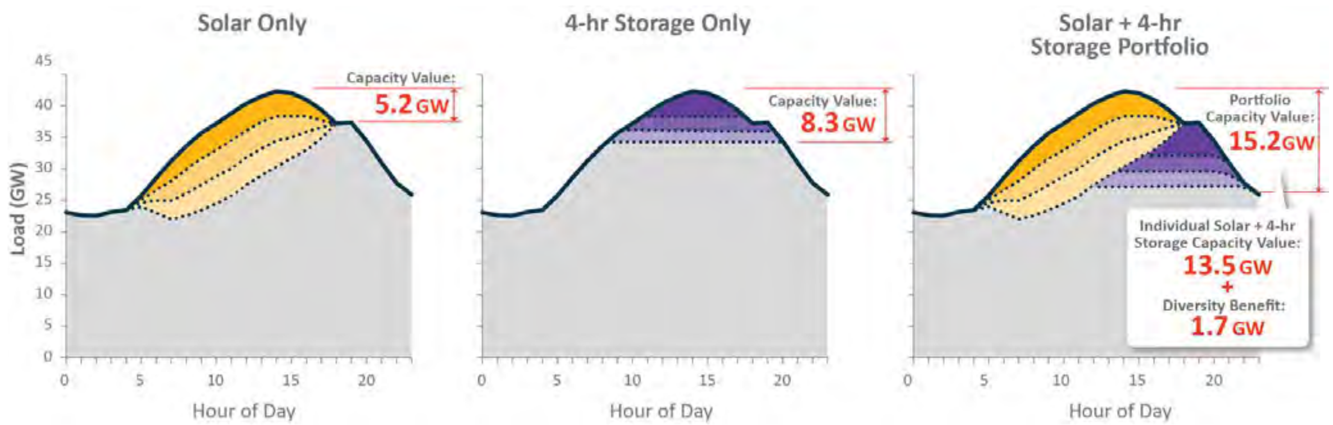
RECAP's ELCC calculations capture interactive or "portfolio" effects from the addition of different types of resources to the portfolio

+ Different types of resources interact with each other, creating portfolio effects in which the total ELCC derived from the portfolio is greater than the sum of marginal ELCC values from individual resources
+ Resources with similar characteristics may compete with each other, leading to more rapid marginal ELCC declines
+ As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects increases and becomes a significant factor in system planning



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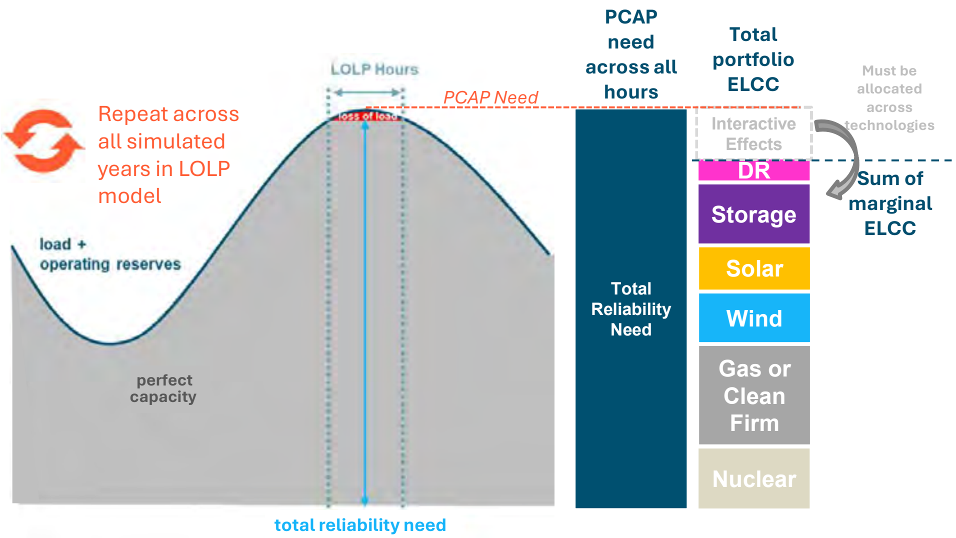
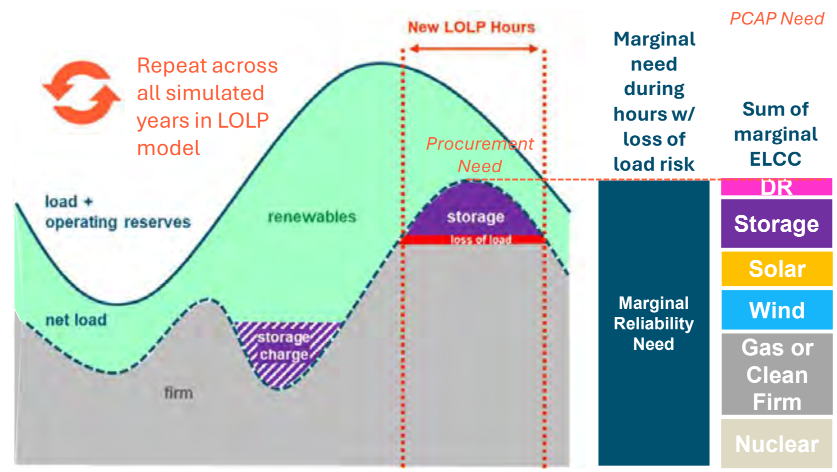
RECAP's ELCC calculations capture the shifting of critical hours from "gross peak" to "net peak" resulting from higher penetrations of solar energy

- On a system with conventional resources, resource adequacy events typically coincide with peak load periods
- ICAP accreditation is independent of the timing of peak load needs

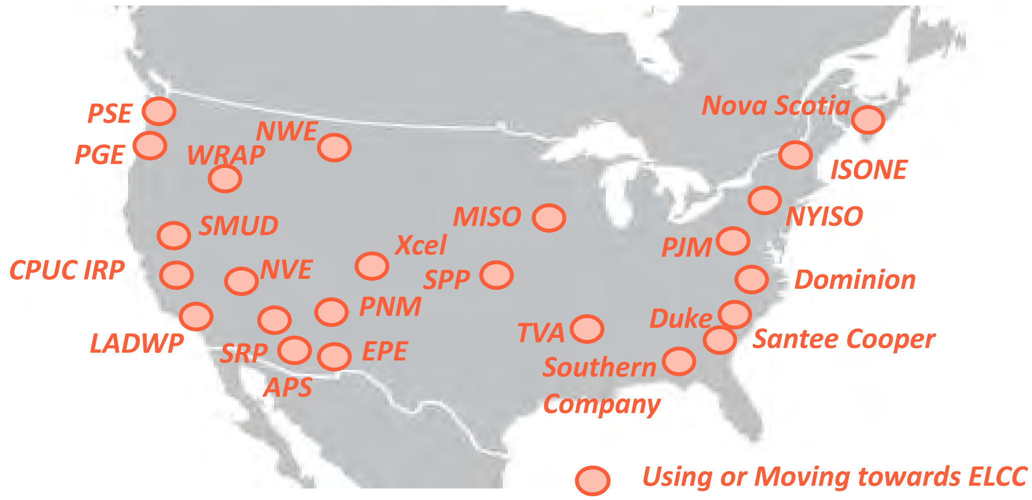


- On a system with high solar penetration, resource adequacy events typically occur after sundown when solar generation is low
- Marginal ELCC accreditation captures resource performance during these new critical hours



ELCC is increasingly used by utilities and ISOs across the country

+ Many ISO/RTOs and utilities are already using or considering a transition to ELCC for renewable (e.g., solar, wind) and/or energy limited resources (e.g., storage)



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Resource Adequacy Study Results for Florida Power & Light

Reliability Results Summary

Model Year	Median Peak Load	Perfect Capacity Reserve Margin Target	Total Reliability Need	Portfolio Capacity Value (ELCC Methodology)	Capacity Shortfall	Achieved Loss of Load Expectation
	MW	*% of Peak*	*Firm MW*	*Firm MW*	*Firm MW*	*Days per Year*
2027 TYP *+1,400MW Batteries*	29,708		32,322	32,049	(273)	0.11
2028	30,283		32,948	32,929	(19)	0.10
2029	30,831	8.8%	33,544	33,440	(104)	0.13
2030	31,344		34,102	33,991	(112)	0.13
2035	34,847		37,914	36,696	(1,218)	0.33
Derivation:	*A*	*B*	*C = A x (1+B)*	*D*	*E = D – C*	*F*

Load & Resources Table 2027 – Ten-Year Site Plan (TYP) Portfolio

LOLP-Derived Methodology

		2027		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,281	25,197	89%
2	Utility Solar (Fixed + Tracking)	8,946	1,407	16%
3	Behind-the-meter (BTM) Solar[1]	2,125	83	4%
4	Storage	991	923	93%
5	Demand Response (DR)	1,951	1,703	87%
6	Portfolio Effect/Peak to Net Load Shift		1,348	
7	**Portfolio ELCC** *(E3 Methodology)*	42,294	30,659	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	29,708		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,322		
12	Firm Capacity Surplus / Shortfall	*-1663*		

- All resource accredited using a marginal ELCC methodology
- For 2028 and beyond, utility solar and BTM solar marginal ELCC is derived from a single marginal solar value, allocated out based on the 2027 marginal values
- For 2028 and beyond, Storage and DR marginal ELCC is derived from a single marginal storage value, allocated out based on the 2027 marginal storage and DR values

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2027 – TYP Portfolio +1,400 MW of Storage

LOLP-Derived Methodology

		2027 +1,400 MW of Storage		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,281	25,197	89%
2	Utility Solar (Fixed + Tracking)	8,946	1,516	17%
3	Behind-the-meter (BTM) Solar[1]	2,125	169	8%
4	Storage	***2,391***	1,808	76%
5	Demand Response (DR)	1,951	1,584	81%
6	Portfolio Effect/Peak to Net Load Shift		1,775	
7	**Portfolio ELCC** *(E3 Methodology)*	43,694	32,049	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	29,708		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,322		
12	Firm Capacity Surplus / Shortfall	*-273*		

- **Additional 1,400 Nameplate MW of Storage relative to the 2027 TYP portfolio**
- **This reduces the capacity shortfall by 1,390 Firm MW**
- **Marginal ELCC of solar is higher with more storage**
- **Marginal ELCC of storage and DR is lower with higher storage penetration**

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2028

	LOLP-Derived Methodology	2028		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,362	25,269	89%
2	Utility Solar (Fixed + Tracking)	9,840	1,424	14%
3	Behind-the-meter (BTM) Solar[1]	2,593	176	7%
4	Storage	3,211	1,596	50%
5	Demand Response (DR)	1,945	1,038	53%
6	Portfolio Effect/Peak to Net Load Shift		3,425	
7	**Portfolio ELCC** *(E3 Methodology)*	45,951	32,929	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	30,283		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,948		
12	Firm Capacity Surplus / Shortfall	*-19*		

+ **Requirement grows by 626 MW due to load growth**
+ **Resources added:**
  - 81 MW more thermal
  - 1,362 MW more solar reduces marginal ELCC by 1-3 percent
  - 820 MW more storage reduces marginal ELCC by 26 percent
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2029

	LOLP-Derived Methodology	2029		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,197	25,122	89%
2	Utility Solar (Fixed + Tracking)	11,628	1,230	11%
3	Behind-the-meter (BTM) Solar[1]	3,118	155	5%
4	Storage	3,807	1,614	42%
5	Demand Response (DR)	1,945	885	46%
6	Portfolio Effect/Peak to Net Load Shift		4,434	
7	**Portfolio ELCC** *(E3 Methodology)*	48,695	33,440	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	30,831		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	33,544		
12	Firm Capacity Surplus / Shortfall	*-104*		

- **Requirement grows by 596 MW due to load growth**
- **Resource changes from 2028:**
  - 165 MW less thermal
  - 2,313 MW more solar reduces marginal ELCC by 2-3 percent
  - 596 MW more storage reduces marginal ELCC by 8 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2030

LOLP-Derived Methodology		2030		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,194	25,119	89%
2	Utility Solar (Fixed + Tracking)	13,416	897	7%
3	Behind-the-meter (BTM) Solar[1]	3,704	116	3%
4	Storage	4,403	1,647	37%
5	Demand Response (DR)	1,944	781	40%
6	Portfolio Effect/Peak to Net Load Shift		5,430	
7	**Portfolio ELCC** *(E3 Methodology)*	51,661	33,991	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	31,344		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	34,102		
12	Firm Capacity Surplus / Shortfall	*-112*		

- **Requirement grows by 558 MW due to load growth**
- **Resource changes from 2029:**
  - 3 MW less thermal
  - 2,374 MW more solar reduces marginal ELCC by 4-8 percent
  - 596 MW more storage reduces marginal ELCC by 5 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2035

	LOLP-Derived Methodology	2035		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	27,942	24,895	89%
2	Utility Solar (Fixed + Tracking)	24,517	382	2%
3	Behind-the-meter (BTM) Solar[1]	7,244	53	1%
4	Storage	7,383	1,786	24%
5	Demand Response (DR)	1,945	505	26%
6	Portfolio Effect/Peak to Net Load Shift		9,074	
7	**Portfolio ELCC** *(E3 Methodology)*	69,031	36,696	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	34,847		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	37,914		
12	Firm Capacity Surplus / Shortfall	*-1,218*		

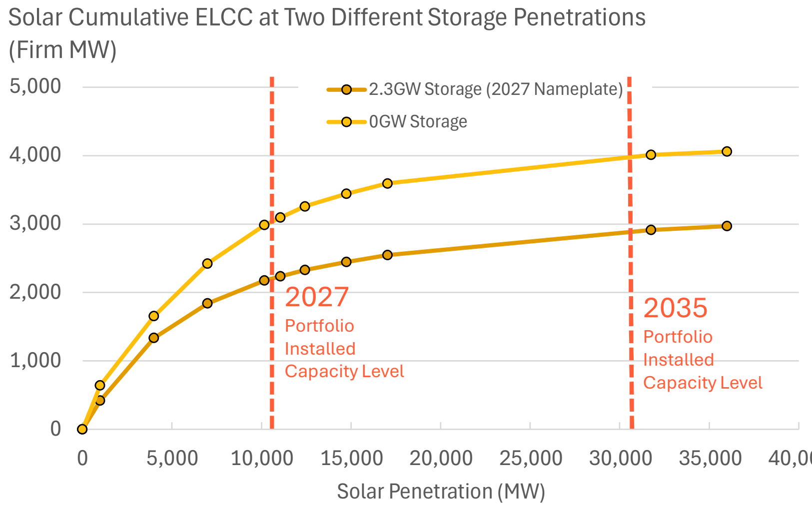
+ **Requirement grows by 3,812 MW due to load growth**
+ **Resource changes from 2030:**
  - 252 MW less thermal
  - 14,641 MW more solar reduces marginal ELCC to 2 percent
  - 2,980 MW more storage reduces marginal ELCC to 24 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

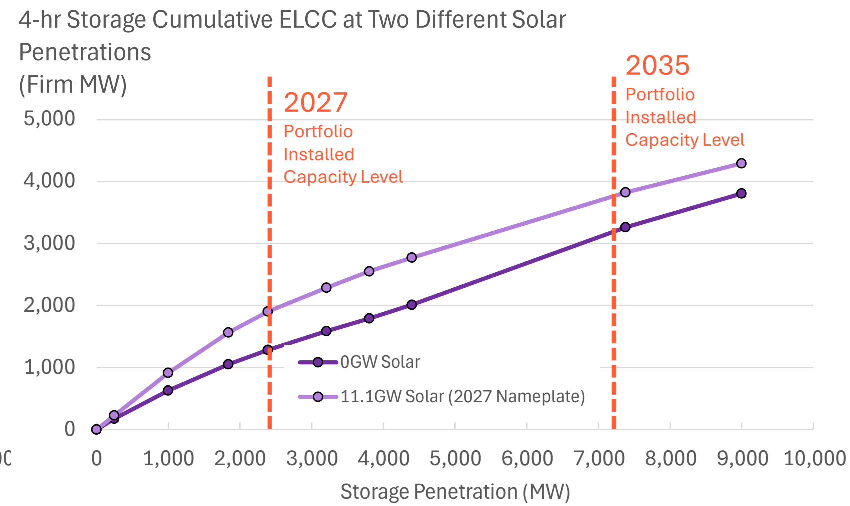
1) MW AC, assuming ILR = 1/0.85

Effective Load Carrying Capability Results

Energy+Environmental Economics

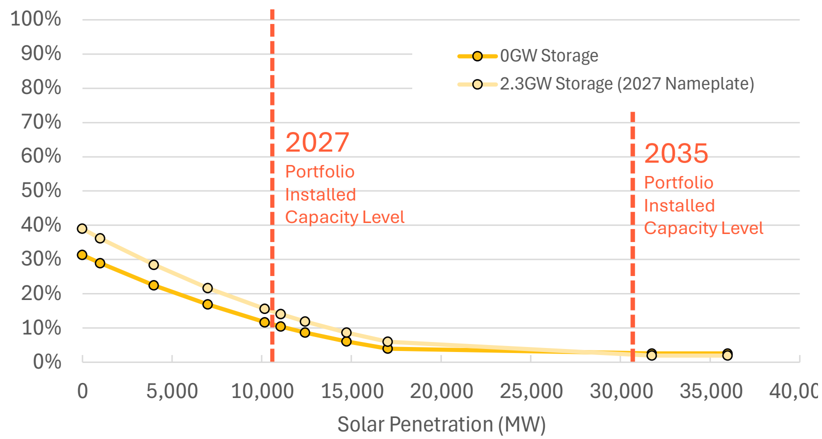
Solar and Storage Cumulative ELCC (Firm MW)



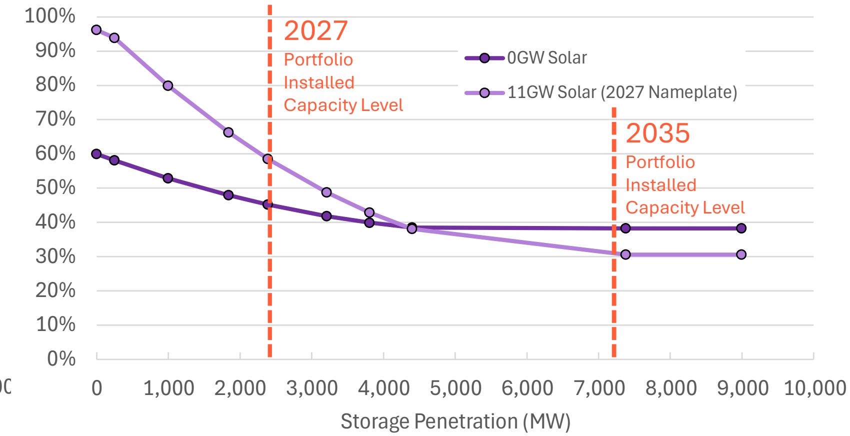


Solar and Storage Marginal ELCC (% of Nameplate MW)

Solar Marginal ELCC at two Different Storage Penetrations
(% of Solar Nameplate Capacity)



4-hr Storage Marginal ELCC at Three Different Solar Penetrations
(% of Storage Nameplate Capacity)

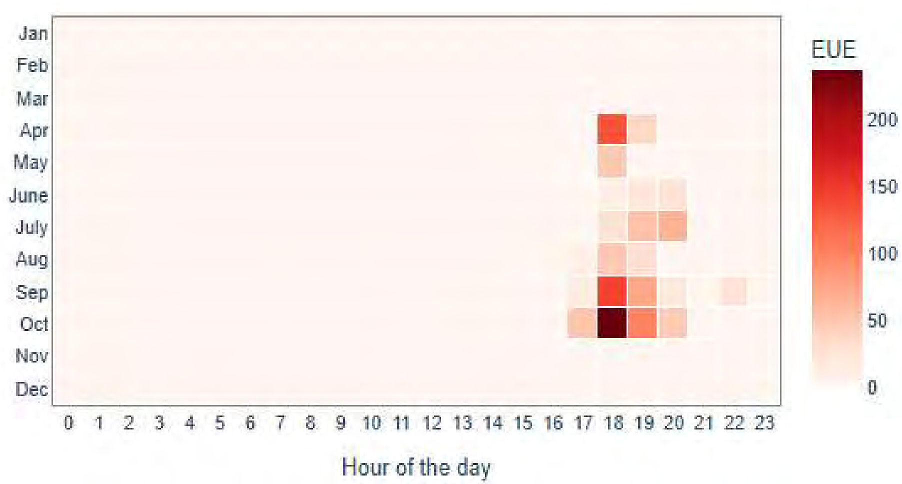


LOLP Heat Map in 2027

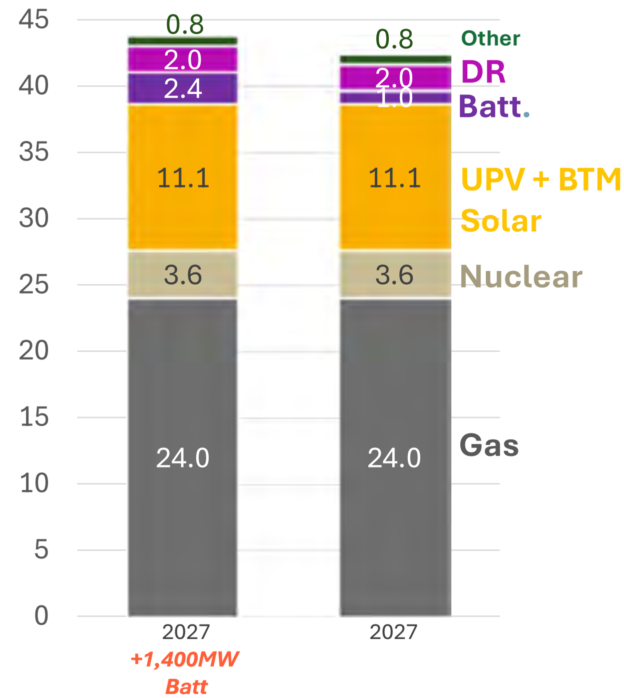
+ Observations

- Loss of load risk is mostly concentrated in summer evenings
- Outages also occur during shoulder months (spring and fall) when maintenance and forced outages occur simultaneously
- Loss of load occurs in late evenings, or during low solar periods

2027 Month-Hour Average Unserved Energy, *(MWh)*



2027 Portfolios,
Nameplate MW



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Load Forecasts Used in the Current Analyses*

	(1)	(2)	(3)
Year	**Summer Peak (MW)**	**Winter Peak (MW)**	**Net Energy For Load (GWh)**
2025	28,312	23,042	144,793
2026	28,664	23,323	144,931
2027	28,925	23,648	145,905
2028	29,333	24,136	148,562
2029	29,687	24,603	150,976
2030	29,982	25,011	153,094
2031	30,301	25,384	154,375
2032	30,823	25,852	156,728
2033	31,257	26,245	158,922
2034	31,677	26,638	160,473
2035	32,112	27,045	162,209
2036	32,547	27,461	164,006
2037	32,962	27,873	165,643
2038	33,356	28,281	167,117
2039	33,709	28,676	168,417
2040	34,027	29,060	169,482
2041	34,285	29,422	170,443
2042	34,348	29,590	169,858
2043	34,562	29,938	170,506
2044	34,731	30,269	170,984
2045	34,904	30,421	171,836
2046	35,078	30,573	172,692
2047	35,252	30,726	173,554
2048	35,427	30,880	174,419
2049	35,604	31,035	175,289
2050	35,781	31,190	176,163
2051	35,959	31,346	177,042
2052	36,138	31,503	177,926
2053	36,318	31,661	178,814
2054	36,499	31,820	179,707
2055	36,681	31,979	180,604
2056	36,863	32,140	181,506
2057	37,047	32,301	182,413
2058	37,232	32,463	183,324
2059	37,417	32,626	184,240
2060	37,604	32,789	185,161
2061	37,791	32,954	186,086
2062	37,980	33,119	187,016
2063	38,169	33,286	187,952
2064	38,360	33,453	188,891
2065	38,551	33,621	189,836
2066	38,743	33,790	190,786
2067	38,937	33,959	191,740
2068	39,131	34,130	192,700
2069	39,327	34,301	193,665
2070	39,523	34,474	194,634
2071	39,720	34,647	195,608

* Load forecasts used in resource planning analyses do not include the projected impacts of existing load management programs or of incremental load management and energy conservation utility DSM programs. Those impacts are addressed as line item adjustments to the load forecasts in the resource planning models.

Fuel Cost Forecasts Used in the Current Analyses
(September 3, 2024 Forecast, Nominal $)

Year	FGT Firm Gas ($/MMBTU)	Gulfstream Firm Gas ($/MMBTU)	Sabal Trail Firm Gas ($/MMBTU)	Residual Oil ($/MMBTU)	Distillate Oil ($/MMBTU)	Scherer 3 Coal Price ($/MMBTU)
2025	3.34	3.24	3.73	13.86	17.41	3.12
2026	3.77	3.60	4.24	13.38	17.26	3.20
2027	4.59	4.34	4.82	14.21	17.96	3.28
2028	4.70	4.37	4.73	14.45	18.42	3.62
2029	5.05	4.68	5.04	16.08	20.02	3.68
2030	5.11	4.72	5.10	16.17	20.48	3.70
2031	5.15	4.76	5.14	16.13	20.76	3.75
2032	5.43	5.05	5.42	16.22	21.10	3.80
2033	5.90	5.52	5.88	16.33	21.54	3.85
2034	6.12	5.73	6.09	16.37	21.96	3.90
2035	6.60	6.21	6.56	16.39	22.28	3.94
2036	6.82	6.43	6.78	16.41	22.66	3.99
2037	6.90	6.50	6.85	16.42	22.97	4.04
2038	7.05	6.66	7.01	16.52	23.50	4.10
2039	7.25	6.86	7.20	16.53	23.90	4.17
2040	7.62	7.22	7.56	16.58	24.45	4.24
2041	7.94	7.54	7.87	16.62	24.78	4.31
2042	8.19	7.79	8.12	16.64	25.31	4.38
2043	8.52	8.12	8.44	16.65	25.74	4.45
2044	8.74	8.34	8.66	16.67	26.34	4.52
2045	9.12	8.71	9.03	16.68	26.89	4.61
2046	9.90	9.49	9.79	16.68	27.38	4.68
2047	10.46	10.05	10.34	16.69	27.88	4.76
2048	11.05	10.64	10.92	16.69	28.39	4.85
2049	11.63	11.22	11.50	16.69	28.95	4.95
2050	12.33	11.92	12.18	16.72	29.58	5.05
2051	12.28	11.87	12.13	16.71	29.67	5.14
2052	12.23	11.81	12.08	16.69	29.76	5.24
2053	12.18	11.76	12.03	16.68	29.84	5.34
2054	12.13	11.71	11.98	16.67	29.93	5.43
2055	12.08	11.66	11.93	16.66	30.02	4.25
2056	12.03	11.61	11.88	16.65	30.12	5.63
2057	11.98	11.56	11.83	16.63	30.21	5.72
2058	11.92	11.51	11.78	16.62	30.30	5.82
2059	11.87	11.46	11.73	16.61	30.39	5.92
2060	11.82	11.41	11.68	16.60	30.48	6.01
2061	11.78	11.36	11.64	16.58	30.57	6.11
2062	11.73	11.31	11.59	16.57	30.66	6.21
2063	11.68	11.26	11.54	16.56	30.76	6.30
2064	11.63	11.21	11.49	16.55	30.85	6.40
2065	11.58	11.16	11.44	16.54	30.94	6.50
2066	11.53	11.12	11.39	16.52	31.03	6.59
2067	11.48	11.07	11.35	16.51	31.13	6.69
2068	11.43	11.02	11.30	16.50	31.22	6.79
2069	11.38	10.97	11.25	16.49	31.32	6.88
2070	11.34	10.92	11.21	16.48	31.41	6.98
2071	11.29	10.88	11.16	16.46	31.51	7.08

CO_2 Compliance Cost Forecast Used in the Current Analyses
(2022 Q4 ICF Forecast, Nominal $)

Year	CO_2 Cost ($/ton)
2025	0.0
2026	0.0
2027	0.0
2028	0.0
2029	0.0
2030	0.0
2031	0.0
2032	0.0
2033	0.0
2034	0.0
2035	0.0
2036	3.3
2037	6.7
2038	10.3
2039	14.1
2040	18.0
2041	20.6
2042	23.7
2043	27.2
2044	31.3
2045	36.0
2046	40.1
2047	44.7
2048	49.9
2049	55.7
2050	62.1
2051	63.4
2052	64.7
2053	66.1
2054	67.5
2055	68.9
2056	70.3
2057	71.8
2058	73.3
2059	74.9
2060	76.4
2061	78.0
2062	79.7
2063	81.4
2064	83.1
2065	84.8
2066	86.6
2067	88.4
2068	90.3
2069	92.2
2070	94.1
2071	96.1

Economic Analysis Results for the Proposed 2026 and 2027 Solar And Battery Additions

Common to all Plans Retirements / Additions	Year	Without Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)	With Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL	22.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1
Broward South (4 MW)	2027	---	21.1	1,192 MW Solar 819.5 MW Battery	27.2
Lansing Smith A (32 MW)	2028	1 x 2x0 Manatee CT (475 MW)	21.0	---	25.3
---	2029	1 x 2x0 Manatee CT (475 MW)	21.2	---	23.8
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	1 x 2x0 Manatee CT (475 MW)	21.1	---	22.0
---	2031	1 x 2x0 Manatee CT (475 MW)	21.5	---	20.7
---	2032	1 x 2x0 Manatee CT (475 MW)	20.9	1 x 2x0 Manatee CT (475 MW)	20.0
---	2033	1 x 2x0 Manatee CT (475 MW)	20.8	2 x 2x0 Manatee CT (950 MW)	21.6
---	2034	1 x 2x0 Manatee CT (475 MW)	20.5	1 x 2x0 Manatee CT (475 MW)	21.2

	Without Proposed 2026 and 2027 Solar And Battery Additions	With Proposed 2026 and 2027 Solar And Battery Additions
CPVRR Costs =	**$108,841**	**$106,899**
CPVRR Costs Difference from the Without Proposed Solar and Battery Additions Plan =	--	**($1,942)**

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers
Analysis assumes new CT capacity is available in 2028 to put plans on equal footing; realistically new CT installations would not be available until late 2029 or early 2030 at the earliest

Economic Analysis Results for the Proposed 2028 and 2029 Solar And Battery Additions

Common to all Plans **Retirements / Additions**	**Year**	**Without Proposed 2028-2029 Solar And Battery Additions**	**Reserve Margin (%)**	**With Proposed 2028-2029 Solar And Battery Additions**	**Reserve Margin (%)**
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1
Broward South (4 MW)	2027	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar 819.5 MW Battery	27.2
Lansing Smith A (32 MW)	2028	---	25.3	1,490 MW Solar 596 MW Battery	26.6
---	2029	---	23.8	1,788 MW Solar 596 MW Battery	26.3
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	---	22.0	---	24.5
---	2031	---	20.7	---	23.2
---	2032	1 x 2x0 Manatee CT (475 MW)	20.0	---	20.9
---	2033	2 x 2x0 Manatee CT (950 MW)	21.6	1 x 2x0 Manatee CT (475 MW)	20.8
---	2034	1 x 2x0 Manatee CT (475 MW)	21.2	1 x 2x0 Manatee CT (475 MW)	20.5

	Without Proposed	With Proposed
CPVRR Costs =	**$106,899**	**$104,686**
CPVRR Costs Difference from the Without Proposed 2028-2029 Solar and Battery Additions Plan =	**--**	**($2,213)**

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers

With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis

	(1)	(2)	(3)	(4)	(5)
Year	**Common to All Plans** **Retirements/Additions**	**"With Programs" Resource Plan**	**Reserve Margin (%)**	**"Without Programs" Resource Plan**	**Reserve Margin (%)**
2025	Pea Ridge (12 MW)	894 MW Solar	22.4	894 MW Solar	22.4
2026	---	894 MW Solar 522 MW Battery in NWFL 1,419.5 MW Battery	24.1	894 MW Solar 522 MW Battery in NWFL 1,519.5 MW Battery	20.1
2027	Broward South (4 MW)	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar 819.5 MW Battery	23.1
2028	Lansing Smith A (32 MW)	1,490 MW Solar 596 MW Battery	26.6	1,490 MW Solar 596 MW Battery	22.6
2029	---	1,788 MW Solar 596 MW Battery	26.3	1,788 MW Solar 596 MW Battery	22.3
2030	GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2,235 MW Solar 596 MW Battery	25.8	2,235 MW Solar 596 MW Battery	21.8
2031	---	2,235 MW Solar 596 MW Battery	25.7	2,235 MW Solar 596 MW Battery	21.8
2032	---	2,235 MW Solar 596 MW Battery	24.5	2,235 MW Solar 596 MW Battery	20.7
2033	---	2,235 MW Solar 596 MW Battery	23.9	2,235 MW Solar 820 MW Battery	20.3
2034	---	2,235 MW Solar 596 MW Battery	23.0	2,235 MW Solar 2,980 MW Battery	21.4
	CPVRR Cost of Resource Plans =	**$99,322**		**$100,390**	
	CPVRR Impact for Removing CDR + CILC =	**---**		**$1,069**	

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071

Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs

Assumptions:	
Assumption (1): Projected CPVRR Net Benefits for CDR & CILC (millions)	$1,069
Assumption (2): CPVRR Admin Costs (millions)	$10
Assumption (3): Current CDR Monthly Incentive Level ($/kW)	$8.76
Assumption (4): Discount rate	8.15%
Assumption (5): Average Monthly MW of CDR & CILC	792
Assumption (6): Time Period Over Which CPVRR Costs are Calculated	2025 thru 2071
Assumption (7): CPVRR Cost of $1/kW Monthly Incentive Payment for 1 MW (see calculation below)	$143,232

	(1)	(2)	(3)	(4)
		= (Monthly Incentive x Assumption 5 x Assumption 7) /1,000,000	= (2) + Assumption 2	= (1) / (3)
Scenario	**CPVRR Net Benefits (Millions)**	**CPVRR Cost of Incentives Only (Millions)**	**CPVRR Total Cost: Incentives + Admin Costs (Millions)**	**RIM Benefit-to-Cost Ratio**
Scenario 1: With Current Monthly Incentive Level of $8.76/kW:	$1,069	$994	$1,004	**1.06**
Scenario 2: With Proposed Monthly Incentive Level of $6.22/kW:	$1,069	$706	$716	**1.49**

Year	**Annual Incentive Cost for 1 MW at $1/kW-mo.**
2025	$0
2026	$12,000
2027	$12,000
2028	$12,000
2029	$12,000
2030	$12,000
2068	$12,000
2069	$12,000
2070	$12,000
2071	$12,000
CPVRR =	**$143,232**

(Note: rows for years 2031 thru 2067 are not shown to save space; those annual values are identical to the annual values that are shown.)