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July 9, 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-referenced docket are the rebuttal testimony and exhibits of FPL witness Nicholas L. Phillips.

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

Sincerely,

s/ Maria Jose Moncada
Maria Jose Moncada
Assistant General Counsel
Florida Power & Light Company

(Document 14 of 16)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by Electronic Mail to the following parties of record this _9th_ day of July 2025:

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250011-EI

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF NICHOLAS L. PHILLIPS

Filed: July 9, 2025

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicholas L. Phillips. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina, 29926.

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

A. I am a Director at Atrium Economics, LLC ("Atrium"), a management consulting and financial advisory firm focused on the North American energy industry.

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

A. In my position as a Director with Atrium, I provide consulting services and expert witness testimony on behalf of clients across North America. Engagements most often center around regulated utilities with scopes of services typically (though not limited to) involving regulatory strategy, resource planning, class cost of service, rate design new allocation methods, and new service offerings. When conducting engagement with our clients, I am responsible for overall project strategy and execution, personnel and budget management, as well as the preparation of studies, reports and testimonial support.

Q. Please describe your educational background and professional experience.

A. I have a Degree of Master of Engineering in Electrical Engineering with a concentration in Electric Power and Energy Systems from Iowa State University of Science and Technology, and a Degree of Master of Science in Computational Finance and Risk Management from the University of Washington Seattle. I joined Atrium from Public Service Company of New Mexico ("PNM") where I directed the Resource Planning and Load Forecasting departments. I was responsible for developing PNM's triennial

Integrated Resource Plan as well as providing strategic, analytical and regulatory support for resource planning decisions such as asset retirement and acquisition decisions. I was also in charge of long-term resource adequacy studies and supply side resiliency analysis as PNM. Prior to my time at PNM, I provided consulting and expert witness services to clients across the country focused on energy, regulated utility, and competitive electric service issues including resource planning, transmission planning, production cost analysis, electric price forecasting, load forecasting, class cost of service analysis, and rate design.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. No.

Q. Have you testified in other jurisdictions?

A. Yes. I have presented expert testimony in state public utility regulatory proceedings in California, Idaho, Kansas, Michigan, Missouri, New Hampshire, New Mexico, Nevada, Wisconsin, and Wyoming. I have also provided expert testimony to the Federal Energy Regulatory Commission ("FERC"). My testimony and expert reports relate to various utility regulatory issues such as resource planning, cost of service, rate design, wholesale market structure and wholesale rate design, retail open access, impact fees, and other regulated electric issues.

Q. On whose behalf are you testifying?

A. I am filing rebuttal testimony on behalf of Florida Power & Light Company ("FPL" or the "Company").

Q. What is the purpose of your rebuttal testimony?

A. The primary purpose of my rebuttal testimony is to address the testimonies filed by intervenor parties in this proceeding who have taken positions against FPL's proposed change to its allocator for fixed production revenue requirements ("Production Allocator"). As outlined in the direct testimony of FPL witness DuBose, FPL is proposing to alter the current Production Allocator from 12CP and 1/13th energy to a 12CP and 25% energy allocation. Intervenors Florida Retail Federation ("FRF"), the Florida Industrial Power Users Group ("FIPUG"), the Federal Executive Agencies ("FEA"), Florida Rising, Inc., the League of Latin American Citizens, and the Environmental Confederation of Southwest Florida (collectively "FEL"), and Walmart Inc. have taken positions opposing this change. I will rebut these witnesses and explain why FPL's proposed change is reasonable. Please note that I am responding to specific issues. Consequently, any argument raised in the testimony presented by intervening parties to which I do not respond, should not be accepted as my support or approval of the positions offered.

Q. Please summarize your rebuttal testimony.

A. Based on my independent review of FPL's system and planning, I conclude that FPL's proposal to continue to use a 12 month coincident peak ("12CP") demand and to modify the energy weighting within its Production Allocator from 1/13th energy to 25% energy is reasonable and consistent with the transformation of the system to include more fixed cost energy related resources, such as solar. Therefore, in my opinion, it would be reasonable for the Commission to approve FPL's proposed Class

Cost of Service Study ("COSS"), including FPL's proposed changes to the Production Allocator.

Q. How is your rebuttal testimony organized?

A. I will begin my presentation by discussing some background concepts fundamental to understanding Class Cost of Service, offering a couple hypothetical examples to illustrate key concepts necessary to understand the basis for FPL's proposal. In doing so, I will also identify and discuss a thematic fallacy contained in the reasoning used by numerous intervening parties that criticize FPL's proposed Production Allocator. Then I will provide a specific discussion regarding the reasonableness of the continued use of 12CP and the proposed change in the energy weight used in the Production Allocator from 1/13th energy to 25% energy. Finally, I provide rebuttal to select statements made by intervening parties, which, in my opinion, are not reasonable or appropriate from a cost of service perspective.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit NLP-1 Qualifications of Nicholas L. Phillips
- Exhibit NLP-2 Numerical example demonstrating why resource characteristics must be considered within cost allocation rather than only considering fixed and variable costs
- Exhibit NLP-3 Demonstration of solar resource capacity and energy split within the 12CP and 25% Production Allocator

Q. Before addressing the intervenors testimony regarding FPL's proposed COSS, can you please summarize what you reviewed in preparing your rebuttal testimony?

A. Yes. The opinion and conclusions in my rebuttal testimony are based on my review of various sources or information, including FPL's historic load patterns, FPL's recent Ten Year Site Plans ("TYSP"), other recent regulatory filings, and the Resource Adequacy study attached to FPL witness Whitley's Testimony direct testimony as Exhibit AWW-1. I also interviewed members of FPL's resource planning, operations and cost of service teams. Finally, I reviewed the following intervenor testimonies: FIPUG witnesses Jeffry Pollock and Jonathan Ly; FRF witness Tony Georgis; FEA witness Matthew P. Smith; Walmart witness Lisa V. Perry; and FEL witness Karl R. Rabago.

II. BACKGROUND ON SYSTEM PLANNING AND COST ALLOCATION

Q. What is a COSS?

A. A COSS is an analysis of costs that assigns to each customer or rate class its proportionate share of the utility's total cost of service, *i.e.*, the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

Q. What is the purpose of a COSS?

A. The purpose of an COSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return provided by each class can be determined. This resulting rate of return will be impacted by the cost allocation resulting from the methodology employed. The COSS is a tool that analysts use to assist in determining revenue responsibility by rate class and rate design. The results of the COSS will provide the analyst with the data necessary to design cost-based rates.

Q. Is there a guiding principle that can support the appropriate allocation of costs?

A. Although there may not be a perfect methodology for allocating costs, the principle of cost causation should be followed to produce more accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. In other words, the costs assigned or allocated to particular customers should be those that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. What are the steps to performing an COSS?

A. To establish the cost responsibility of each customer class, initially, a three-step analysis of the utility's total operating costs must be undertaken. The three steps that comprise the COSS modeling are: (1) cost functionalization, (2) cost classification, and (3) cost allocation of all the costs of the utility's system.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The three most general functional categories are Production, Transmission and Distribution though many utilities will utilize additional functional or sub-functional categories to detail the functional breakdown of costs. FPL's primary functional cost categories associated with electric service include Production, Transmission, and Distribution. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent that their costs vary in response to different customer class characteristics.

Q. Please describe cost classification.

A. The second step, cost classification, further separates the functionalized plant and expenses according to whether the costs are predominantly related to demand, energy or number of customers. Customer related costs are costs predominantly driven by the number of customers on the system, for example, the number of meters. Traditionally, energy related costs are costs that vary by the number of kilowatt-hours (kWh) produced or consumed such as fuel expense. Demand related costs traditionally are costs incurred by the utility in order to meet a capacity or firm-service requirement and must be sized in order to meet the maximum amount of kilowatts (kW) placed on the system in a short interval of time. Traditional examples of demand related costs are the fixed costs in generation plant and transmission lines. Many analysts traditionally equate demand related costs with fixed costs and energy related costs with variable costs. However, this is where the thematic fallacy repeated by numerous intervening parties arises, which I will discuss in more detail shortly.

Q. Please describe cost allocation

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Customers are generally divided into customer classes based on the type and character of services they require. Costs typically are allocated to these customer classes based on factors related to the number of customers, the amount of capacity demanded by customers, and the energy usage of customers.

Q. You mentioned that a thematic fallacy is repeated by numerous intervening parties in the classification step, please explain.

A. The fallacy that is repeated by multiple intervenors is that *all* fixed costs are demand related and *all* variable costs are energy related. I agree that logic was true when the sources of generation were mainly limited to thermal technologies, which combusted fuel such as gas or coal (or in the case of nuclear utilized uranium though reacted not combusted) to boil water creating steam that is then put through a steam turbine to produce electricity. For such sources of generation, I completely agree that the fixed costs to construct a plant of a certain size is a demand related cost and that the amount of fuel used to produce energy from hour to hour is an energy related cost. However, the same is not necessarily always true for renewable energy resources, such as wind or solar. These technologies have virtually no variable cost but do provide energy to the system. The fallacy exists when blindly asserting that all fixed costs are demand related without considering the type of resources that underlie the costs.

Q. Are you suggesting that the tried-and-true principles of cost allocation need to be thrown out?

A. No, not at all. While it is undeniable that electric systems are undergoing transformative changes, the fundamental components of the system and the associated characteristics remain, as do the economic underpinnings of regulated cost of service. Customers still place demand and energy burdens on the system; however, the timing and impact of customer requirements must now also be balanced against a more intermittent and energy-limited supply as the penetration of renewable and energy limited resources interconnected to the system increases. In order to reliably serve the demand and energy needs of their customers, utilities must incur both fixed and variable costs. However, more and more costs are becoming fixed costs as steel in renewable resources replace fuel costs. What is continuing to change are the types and attributes of resources necessary to provide safe and reliable service to customers while simultaneously being able to support changing public policy goals, such as reduction of carbon emissions, advancing efficiency, and etc., while doing so at a reasonable cost. These transformative changes in the electric system reinforce the need to dutifully analyze the actual and planned resources and properly allocate those resources based on the underlying attributes of the resources.

Q. Please explain your last statement.

A. Consider the fact that traditional thermal generation assets possessed the ability to provide both capacity and energy to the system. The traditional approach to the classification and allocation of costs essentially decomposed the capital and operating costs of the resource by way of how those costs were incurred, recognizing that fuel and variable operating costs are more closely linked with the energy output of the resource, whereas the fixed investments are more closely tied to the capacity of the resource.

Renewable generation assets also provide both capacity and energy to the system. However, due to the nature of renewable generation assets, such as wind or solar, the amount of capacity that the resource provides varies through the time of day and year, as well as becomes affected by the amount of other renewable and energy limited resources on the system. Further, renewable energy resources do not incur an operating cost, such as fuel, but nevertheless supply energy.

Consequently, it may become necessary to think about the individual attributes and uses of renewable and energy limited resources differently than the traditional approach, but the fundamental characteristics of capacity, energy, fixed, and variable costs certainly remain. The analysts should continue to consider these characteristics and apply fundamental economic reasoning when selecting the appropriate way to classify and allocate costs to customers. While there are many potential alternatives that could be considered, the goal is to identify the method that is the overall best fit for the system being studied. It may not be unreasonable to seek recovery of energy related portions of renewable resources through a fixed or demand related charge; however, the selection of the most reasonable alternative should appropriately consider both the capacity and energy characteristics of the system.

Q. What is the result if cost of service analysts fail to properly consider and reflect these transformative changes in the electric system?

A. The easiest way to explain is by way of example. Consider two systems, the first, System A, is a more traditional system with only conventional thermal resources. The second system, System B, has enough renewable energy resources to meet 80% of its energy needs but still relies on thermal resources for 20% of its energy and reliability requirements. Further assume both systems have identical loads placed on the systems by the respective customer classes. If one were to allocate production and fuel costs for both System A and System B using a 12CP allocator for all "traditional" demand related production expense (*i.e.*, fixed costs) and an energy allocator for energy related production expense without analyzing the capacity and energy characteristics of the resources installed on the system, it would result in outcomes that are not reflective of the system: System A would allocate 100% of demand costs using 12CP and 100% of fuel/energy costs on an energy basis; and System B would allocate 100% of demand and 80% of energy costs (*i.e.*, the renewable energy resources) on 12CP and only 20% of energy costs on an energy basis. This does not make sense when the same demand and energy loads are being served. Attached as Exhibit NLP-2 is a numerical example demonstrating this concept further.

This simplified example illustrates why analysis of the resources themselves are critical when determining a reasonable way to allocate costs. If one were to blindly argue all fixed costs should be allocated on a measure of demand, the outcome would be that high energy/high load factor customers end up paying less and low load factor customers pay more for the same reliable electric service on System B than System A.

Q. What are some potential solutions to this problem?

A. There is no one correct solution and, instead, the analyst must evaluate the system and how it is operated to determine the allocation method that is the most reasonable and best reflects how the system is planned and operated. The problem is complex and will require individualized solutions for each utility, taking into account the types of resources, the speed of the system transition, the precedents in place, and whether the utility and its Commission would prefer an incremental approach or an overhaul to the overall cost allocation paradigm in place.

Notwithstanding the previous statement, I believe that there are two broad categories of remedies for the issue illustrated by the simplified example in the previous question. The first is to classify the renewable energy resources as demand related but utilize an energy-weighted demand allocator that recognizes the fixed production expense being allocated is comprised of both demand and energy related costs. The energy weighted demand should generally be proportional to the amount of energy related dollars included in the functional and classified revenue requirement being allocated with the Production Allocator. This is the same approach that FPL has proposed in its 12CP and 25% Production Allocator. This energy weighting could increase over time as more fixed costs are incurred to provide energy to the system but this is counterbalanced by the avoidance of fuel costs. I like to think of this as swapping steel for fuel.

The second approach, which has largely become available due to the recent passage of FERC Order 898,[1] is to create separate tracking of costs for renewable and energy limited resources and classify these costs differently than the fixed expenses associated with thermal plants. Then the traditional process is applied to allocate demand related

[1] On June 29, 2023, the FERC issued Order 898, Accounting and Reporting Treatment of Certain Renewable Energy Assets in Docket No. RM21-11-000, which, among other things, amended the Uniform System of Accounts for public utilities by creating new plant and Operating and Maintenance ("O&M") accounts for wind, solar, energy storage, and other renewable generating assets. The new accounts under FERC Order 898 became effective January 1, 2025.

costs using a predominantly demand allocation method and energy related costs using a predominantly energy allocation method.

While both of the approaches have their pluses and minuses, as well as details that must be worked through, either approach, if employed correctly, can arrive at reasonable and cost-based outcomes.

Q. Do you have an example to illustrate the impact if costs for renewable and energy limited resources are classified as both demand- and energy-related using one of these two methods you discussed?

A. Yes. Using the same simplified example above and provided in Exhibit NLP-2, the column labeled "System B-2" shows the relative impact to System B if the renewable fixed costs are split on the basis of firm capacity so that the proportion of the costs equivalent to the firm capacity percentage are allocated using the fixed production allocator and the remaining costs are allocated using the energy allocator. In this example, both the total costs and the class load characteristics of the two systems are assumed to be the same to illustrate the differences due to how the renewable resources are treated within the allocation process. What can be seen is that the cost responsibility for each class returns towards the traditional system cost share shown in System A. One would not expect it to be exactly the same as much will depend on the firm capacity value of the renewable resources and the relative costs of the renewable resources compared to the traditional. But one would neither expect large swings given least cost planning principles and the demand and energy characteristics of the systems do not change rapidly, especially given the typical capacity values for current renewable resource technologies and displacement of fuel costs.

Q. You stated that FPL's proposed 12CP and 25% methodology follows the first approach you discussed. Do you know why FPL did not apply the second approach with specific cost allocators for renewable resources?

A. Based on my discussions with the FPL COSS team, it is my understanding that at the time the filing was being prepared, FPL's system was not capable of applying a separate production plant rate class allocator to renewable and energy limited resources in its COSS system. However, as I have shown by way of my simplified example above, maintaining the status quo, or further regressing as suggested by some of the intervening parties, will have unintended consequences and lead to inequitable outcomes. Thus, I believe that FPL's proposed 12CP and 25% Production Allocator is a reasonable and measured approach to better reflect the increase in renewable generation, particularly solar, that is currently on its system and planned for the future. In section IV of this testimony, I demonstrate how the proposed change in the Production Allocator results in a demand and energy split of costs for the solar resources is in line with the proportion of firm capacity provided to FPL's system by the existing and proposed additions of the solar resources. This in turn aligns with the way I have demonstrated in Exhibit NLP-2 that the allocations in the System B example can be corrected as shown in System B-2.

III. REASONABLENESS OF THE 12CP DEMAND ALLOCATION

Q. Have cost causative factors changed in a way that require a shift away from the 12CP demand allocation?

A. No. I performed a review of FPL's system planning approach, load characteristics, and other information and I do not believe that a change to the 12CP portion of the Production allocator is warranted at this time.

Q. The intervenors opposing the 12CP method appear to rely on peak demands. In your opinion, is analyzing peak demands alone sufficient for purposes of understanding cost-causation for production resources?

A. No. The analysis of peak demands alone without examination of attributes of the resources being allocated and review of other planning and operations practices is overly simplistic and only results in a partial view of the overall picture. Furthermore, analyzing a single year or a small number of years, as was done by a number of the intervenors criticizing the use of 12CP, is worse than simplistic; its insignificant. One cannot make meaningful and conclusive inferences from such a limited review.

Q. What historic loads did you review?

A. I reviewed FPL's Balancing Area historic monthly peaks from 1998-2024. Through this review it becomes evident that, while FPL tends to peak in the summer, the Company also experiences significant peaks in the shoulder months and winter months. In fact, FPL hit its annual peak twice during the winter, once in 2003 and again in 2010, and had eight peaks in the winter that were within 90% of its system peak for the same year. I also note that there were 33 instances where FPL experienced shoulder month peaks within 90% of its system peak for the same year. This is shown in Table NLP-

1 below. While the frequency of winter peaking events is lower, the impact and magnitude of these events tends to be more extreme.

Table NLP -1

Number of Occurances a Monthly Peak was within 90% of the System Peak												
Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1998-2024 (27 Years)	6	1	0	3	14	26	26	27	26	16	0	1

Q. Did FPL's TYSP provide any additional information

A. Yes. FPL's TYSPs discuss its load forecasting procedures and particular concerns with winter risk. The FPL 2022-2031 Ten Year Site Plan discusses changes to the way it will account for winter risk in its modeling to better protect its customers from High-Impact Low-Frequency ("HILF") events.[2] FPL discusses that it was adapting its winter load modeling in response to winter storm Uri which left millions in Texas and other parts of the country without electricity noting that similar events occurred in Florida in 1989 and again in 2010.[3] From this discussion, it is evident that winter risk is inherent within the planning process – and rightfully so. Winter peak loads, while less frequently realized, present a much more severe and unpredictable risk and play an important role in prudent planning practices. Notably, solar is generally not available during winter peaking events making this planning even more important as the system continues to add solar.

Q. Does FPL continue to express concern about winter peaks in its current TYSP?

A. Yes. In the 2024-2033 TYSP when discussing load forecast uncertainties and the need for the use of multiple risk metrics, FPL states that:

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[2] FPL 2022-2031 TYSP at page 5.

[3] *Id.* at page 6

> The inherent uncertainty in load forecasting is addressed in different ways regarding the overall resource planning and operational planning work. With respect to resource planning work, the utilization of a 20% total reserve margin (TRM) criterion, a Loss-of-Load-Probability (LOLP) criterion of 0.1 days per year, and a 10% generation-only reserve margin (GRM) criterion are designed to maintain reliable electric service for customers in light of forecasting and other uncertainties. In addition, FPL's Winter peak demands have experienced significantly greater volatility than the Summer peak or NEL, and this greater volatility results in additional risks to FPL's ability to serve winter load. FPL continues to analyze system impacts of Winter peak demands due to this greater volatility.[4]

Q. Are there other examples that highlight the difficulty in predicting winter events?

A. Yes. On Christmas Eve in 2022, Duke Energy Carolinas had to shed firm load due to unexpectedly high winter demand.[5] Other utilities in the Carolinas experienced system peaks during this winter event. The stated reasons for this were the parameters surrounding the event were outside of the load forecasting model, equipment performance during extreme cold became markedly worse and somewhat unpredictable, and the ability to import power decreases during periods of extreme grid stress.[6]

Q. What can you conclude from your review of information related to FPL's planning process and winter events.

A. While winter peaking events are less frequent, they do occur and FPL spends considerable time and effort planning to ensure the system is prepared to manage these

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[4] 2024-2033 TYSP at page 50.

[5] *See* https://spectrumlocalnews.com/nc/charlotte/news/2023/01/03/what-caused-rolling-blackouts-on-christmas-eve--duke-grilled-by-n-c--regulators -:~:text=Equipment%20problems%2C%20software%20failures%2C%20higher-than-expected%20demand%2C%20frigid%20temperatures%2C,that%20led%20to%20rolling%20blackouts%20on%20Christmas%20Eve.

[6] *Id.*

events, should they occur. As seen around the United States in the last few years, the risk of these events is real, and the consequences of these events can be devastating and are likely to increase in the near term with the amount of planned coal and gas plant retirements. In light of the preceding evidence surrounding the historic load patterns and FPL's planning process and risks associated with HILF winter events, I believe that focusing cost allocation to the summer only as proposed by multiple intervenor parties would inappropriately ignore these risks when attributing costs to customer class, risks that are without question part of FPL's planning process.

Q. Are there other factors that contribute to planning for peak demands outside of the summer months for FPL?

A. Yes. During my interviews with the FPL planning and operations groups, another risk that was raised and considered in the planning process was scheduled maintenance. Given that Florida is a peninsula it has more limited access to market imports for power. Ensuring that there is enough internal generation to meet the Company's requirements plus maintain reserves is another factor within its planning process and operations. This is reinforced by the Resource Adequacy study attached to FPL witness Whitley's Testimony direct testimony as Exhibit AWW-1, which includes a loss of load probability ("LOLP") analysis. In particular, on page 30 of that Resource Adequacy study, there is a heatmap that shows loss of load risk that clearly occurs outside of the summer months, in April-May and October, and the study notes that the risk is attributable to the coincidence of maintenance outage and unplanned outages during the shoulder periods. These facts, in conjunction with the review of historic load information presented earlier demonstrate why the shoulder months are also important to consider when selecting which CPs to include when allocating costs to customer classes.

Q. What has the Commission articulated with respect to why it preferred the 12CP and 1/13th energy weighted production allocator in the past?

A. Based on my review of decisions on this issue in litigated base rate proceedings, it appears the Commission has articulated multiple times that it believes fixed production costs should not be assessed solely on peak demands and instead should consider some energy weight. Further, the Commission has upheld the notion that 12CP is appropriate when considering production costs due to the necessary periods of planned maintenance. None of the facts and circumstances related to FPL's system have changed with respect to the use of the 12CP demand component within the energy weighted production allocator. However, the discussion today should not be whether to include an energy weight, but at what level should it be adjusted to reflect the significance of energy related fixed costs included in the fixed production revenue requirement related to renewable energy resources.

Q. Based on the foregoing, what do you conclude about the 12CP demand allocation?

A. I do not believe sufficient evidence exists to support a change in the 12CP demand allocation and recommend that the 12CP continue to be used to allocate the demand component in FPL's partial energy weighted Production Allocator. Although there are multiple alternative demand allocation methods, it is my opinion that continuing to use the 12 CP demand allocation is the overall most reasonable approach for FPL's system for the reasons I explained above, including the consideration of winter peaks and shoulder month operations.

IV. REASONABLENESS OF THE 25% ENERGY WEIGHTING

Q. What is your understanding of why FPL is proposing to change the energy weight used in FPL's Production Allocator?

A. My understanding is that FPL's proposed modification to the energy weight used in the Production Allocator is due to the increasing portfolio of utility owned solar projects on its system.

Q. In your opinion, is an increase in the solar resources included in the generation portfolio a reasonable basis to change the energy weight used in the Production Allocator?

A. Yes. As I noted earlier, solar and other renewable and energy limited resources have distinguishing characteristics that do not fit the traditional template of cost allocation. These characteristics must be examined and taken into consideration when attributing cost responsibility. Specifically, solar has a low capacity value on FPL's system but is economically justified through the planning process primarily based on the low cost energy it provides. Utility owned solar is also a fixed cost resource and the revenue requirements associated with it are combined with other fixed cost plant investments such as nuclear and gas facilities. As a result, the fixed cost revenue requirement being allocated using the Production Allocator now contains a significant portion of energy related costs and this fact should be recognized and treated appropriately.

Q. How will using a 12CP and 25% Production Allocator accomplish this goal?

A. It is my understanding that FPL's current 12CP and 1/13th energy Production Allocator was approved as early as 1982 when there was no solar on the FPL system. Since that time the 12CP and 1/13th allocator has been examined and reaffirmed including in

FPL's 2021 Rate Case. Furthermore, in 2021 when the 12CP and 1/13th Production Allocator was last approved for FPL, FPL only had approximately 3,000 MW of nameplate solar capacity installed whereas it expects to eclipse 10,000 MW by 2027.[7] The 12CP and 1/13th allocation method essentially prescribed a 7.7% (*i.e.*, 1/13) energy value to the resources on the FPL system. Increasing the energy weight to 25% prescribes an incremental 17.3% value of energy to the total fixed cost production revenue requirement. As stated at the outset of this section, the reason for the increase in the energy weight is due to the amount of utility owned solar installation on the FPL system and the associated proportion of that revenue requirement included in the total fixed production revenue requirement. When examined more closely, it can be shown that the proposed increase actually aligns the demand and energy split used in the allocation of the associated revenue requirement with the firm capacity value of the installed and proposed solar resources on the FPL system.

Q. Please explain.

A. Using Net Plant in Service ("NPIS") as a proxy for revenue requirements by Production sub-function, total NPIS is approximately \$33.5 billion for 2026. If the 12CP and 1/13th Production Allocator were used, \$2.58 billion (*i.e.*, 7.7% of NPIS) would be allocated on energy. If the energy weight is increased to 25% as proposed, then a total of \$8.39 billion of the fixed production revenue requirement would be allocated on energy, an increase of \$5.81 billion.

[7] FPL 2021- 2030 TYSP compared to FPL 2024-2033 TYSP.

The total solar NPIS is approximately \$10.5 billion, roughly 31% of the total NPIS. If the incremental energy allocation is considered to be assigned to solar, which is reasonable given that the stated reason for the increase in the energy weight is due to solar, this would bring the total solar revenue requirement allocated on energy to \$6.62 billion (*i.e.*, \$10.5 B x 7.7% + \$5.81B), which represents 63% of the total solar NPIS. The remaining 37% would thereby be treated as demand related within the Production Allocator. This aligns with the 40% and 36% average firm capacity accreditation for the portfolio of solar resources for FPL's system in 2026 and 2027 respectively. In other words, the effect of increasing the energy weight to 25% splits the solar resources consistent with the current demand and energy characteristics of those resources on the system, with the remaining non-solar resources continuing to be allocated using a 1/13th energy weight. I have detailed this breakdown in Exhibit NLP-3.

I note that this is similar to the example presented in Exhibit NLP-2 showing how the deficiency in the System B allocations can be remedied by aligning the resource allocations with their demand and energy attributes, shown in that same exhibit as System B-2. Aligning cost allocations with resource demand and energy characteristics aligns with cost causation and is a reasonable approach to allocate costs to classes. I believe that this is a step in the right direction for FPL given the changes in its generation portfolio since the 2021 Rate Case and planned through 2027. It should be noted that as more renewable resources are added to the system, the energy weight will need to be reviewed to ensure this relationship between cost allocation and system characteristics is maintained.

Q. Does this approach still recognize that solar resources do provide some capacity to the FPL system?

A. Yes. It would be unreasonable to attribute no capacity value to solar. The 12CP utilizes gross peak demands, which solar does provide some capacity towards meeting. As discussed in my previous answer, effectively embedded within the proposed Production Allocator is a 37% capacity accreditation towards meeting gross peak loads, which is consistent with the current average value of embedded solar capacity on FPL's system. One should keep in mind that solar resources do not provide for consistent contributions to gross peak loads across the entire year. During the winter months, solar will provide no contribution to gross peak demands, whereas over the shoulder and summer months solar will contribute to the gross peak demands.

Q. What is the current level of capacity being attributed to solar resources on the FPL system?

A. For planning purposes and associated investment decisions, the marginal capacity value of solar resources used within FPL's planning models is 13% for 2026 and declines to 5% thereafter. However, the average value of all solar installed on FPL's system will range depending on the time of the year from 0% to as high as 50% relative to gross peak loads with an average value of 40% in 2026 and falling to 28% by 2029.[8]

Q. You have used the term gross peak loads a number of times, what is the significance of gross peak versus net peak loads?

A. Gross peak loads represent the total customer peak demand placed on the system seen by FPL at the meter (and grossed up for losses incurred to deliver power from the

[8] See Revised Attachment 1 to FPL response to FEA Third Request for Production of Documents No. 31.

generator to the meter). Net peak loads represent gross peak loads net of renewable production. As discussed by FPL witness Whitley and presented in the Resource Adequacy study in FPL Exhibit AWW-1, due to the amount of solar installed on FPL's system, the net peak has become a greater source of planning risk.

Q. Would it be appropriate to allocate the entire fixed production revenue requirement using net peak loads?

A. No. As I just discussed, net peak loads by definition are those loads that already have the portion of each hours loads served by renewable production removed. It would be inappropriate to allocate the entire revenue required for solar using loads that are not served by solar. Unless FPL modifies its systems to separately allocate solar costs to customer classes in its COSS model, the most appropriate way for FPL to allocate its fixed production revenue requirement is an energy weighted Production Allocator, such as the proposed 12CP and 25%.

Q. In your opinion, is FPL's approach reasonable given its system constraints regarding production cost allocations to customer classes?

A. Yes. Given the amount of solar installed on the FPL system and the associated revenue requirements, it is my opinion that it is appropriate to reflect this change in the COSS. FPL's proposed 12CP and 25% methodology is a reasonable and measured step in the right direction to properly reflect the significant increase in solar on its system since the 2021 Rate Case.

Q. You have focused on the need to reflect the addition of solar resources, but FPL is also forecasting additional Battery Energy Storage Systems ("BESS"). How do BESS fit into the equation?

A. BESS are another complexity that does not have a one size fits all solution in the context of cost allocation. BESS do not produce energy, it only stores energy produced by generators for use at a later time, nor do BESS transmit or distribute energy. However, depending on the needs and operations of the system, BESS can support all three functions of the system. Consequently, care must be taken to ensure that individual BESS installations are tracked and allocated based on the function they are supporting, which may be multiple functions. Given the limited amounts of BESS currently on FPL's system and included in the forecast through the 2027 Projected Test Year, I believe that the most reasonable allocation of the BESS resources is consistent with the traditional assets where the vast majority of the costs are allocated on a measure of demand because these BESS resources were primarily added to provide short duration capacity to the system. However, this does not mean that all BESS should be allocated this way in the future.

Q. What do you conclude regarding the 25% energy weighting component used in the Production Allocator?

A. For the reasons discussed above, I believe that this is a reasonable approach given the changes in FPL's fixed production cost structure and reflects a cost-causative allocation of costs in this case.

V. RESPONSES TO INTERVENING PARTIES

Q. Do you have any observations regarding some of the cost of service arguments or positions advanced by intervenors?

A. Yes. The first is the overarching fallacy discussed in Section II of my testimony -- that is the position that if a resource is a fixed cost, the resource is also 100% demand related. For the reasons I previously explained, it is not appropriate or reasonable to simply ignore changes in FPL's fixed production cost structure and how FPL operates its system, which violates sound resource planning or cost of service principles. I note the opposite position of this was taken by FEL with respect to nuclear generation when recommending to allocate nuclear plant on the basis of energy.[9] This is equally incorrect, but for the antithetical reason, as it ignores the firm capacity that nuclear provides.

Second, both FEA and FIPUG assert that if investment decisions were based on a 12CP average, FPL would not have sufficient resources to serve load. This is a gross misunderstanding of both the planning process and the purpose of a multiple coincident peak allocator. The use of a 12CP allocation factor in no way suggests that the average of the 12CPs should be used for planning. Rather the use of 12CP indicates that each of the twelve months contributes to the overall planning and investment in the system and, consequently, customer demand from each of the twelve months should be used in the apportionment of cost responsibility.

[9] Direct Testimony of FEL witness Rabago at page 17.

Third, FEA's assertion that all resources selected within planning models are justified solely on the contribution to peak demand is a misunderstanding of the planning and cost of service processes. When resource planning models select resources, the models seek to minimize both capital investments and operating costs. That is to say that both the demand and energy characteristics of the system are taken into account and a portfolio of resources is output that minimizes total production cost to meet both the demand and energy characteristics of the system. If FEA's position were true, the models would result in a portfolio of resources that minimized cost for only the peak demand hours. Prudent resource planning, and indeed the models used by FPL, consider the lowest reasonable cost approach to reliably serve customers in all hours of the year. Not all hours contribute to the investments necessary to ensure resource adequacy, but all hours incur cost to meet the energy needs of the system. Consequently, resources with minimal capacity contributions but low operating costs can be selected to offset higher operating costs. All these costs must be considered in the planning process and then the cost of service seeks to attribute these costs to customer classes based on how each of those costs were incurred.

Finally, FRF argues that while the LOLP analysis presented in FPL Exhibit AWW-1 shows loss of load risk in the shoulder months, if scheduled maintenance is removed from those months the loss of load risk is eliminated from those months.[10] This approach improperly ignores the reality of the planning and operation of FPL's system. Scheduled maintenance is a requirement to ensure best possible operations of the fleet.

[10] Direct Testimony of FRF witness Georgis at page 39, lines 12-16.

Arbitrarily removing the scheduled maintenance without addressing when it should be scheduled and the effects on system reliability provides no meaningful information to the Commission and is not an appropriate basis for selecting cost of service methodologies. Cost of service methodologies should be selected to appropriately allocate costs consistent with how those costs are incurred to reliably serve customers, *i.e.*, based on how the system is actually planned and operated.

VI. CONCLUSION

Q. Based on your review of FPL's resource planning process and operations, and the existing and proposed generation portfolio resources on FPL's system, do you have an opinion on FPL's proposed COSS?

A. Yes. Based on my review, it is my opinion that the proposed modifications to FPL's Production Allocator to represent a 12CP and 25% energy is reasonable and appropriately reflects changes in FPL's system.

Q. Does this conclude your testimony?

A. Yes.

Nicholas L. Phillips

DIRECTOR

Mr. Phillips is a seasoned professional in the energy and utility sector, with extensive expertise spanning utility system planning, forecasting, unit costs, power plant operations, costing, ratemaking, and regulatory activities. He has testified in approximately 50 different regulatory proceedings on a wide range of issues for clients across North America, including (but not limited to) utility resource planning, resource adequacy and resiliency, resource retirement and acquisitions, class cost of service and rate design, allocation methods, load forecasting, revenue requirements, production cost analysis, fuel and purchased power costs, off-system sales margins, retail open access, exit fees, market design, avoided cost analysis, renewable portfolio standards, and energy efficiency. His proficiency extends across virtually all aspects of electric and gas issues and has worked on behalf of his clients to evaluate complex issues during a time of transition for utilities and energy users alike.

Prior to joining Atrium as a Director, his previous career includes roles include Director of Integrated Resource Planning at Public Service Company of New Mexico (PNM), where he managed planning and regulatory support, and as a Principal at Brubaker & Associates, Inc. (BAI), where he represented electricity and natural gas customers, testifying before regulatory bodies on utility-related issues.

Mr. Phillips' academic achievements include a Master of Science degree in Computational Finance and Risk Management from the University of Washington - Seattle, a Master of Engineering degree in Electrical Engineering from Iowa State University of Science and Technology, and Bachelor of Science degrees in Electrical Engineering and Criminology and Criminal Justice from the University of Missouri - St. Louis.

EDUCATION

M.S., Computational Finance and Risk Management, University of Washington - Seattle

M.Eng., Electrical Engineering, Iowa State University

B.S., Electrical Engineering, University of Missouri – St. Louis

YEARS EXPERIENCE

16

RELEVANT EXPERTISE

Utility Resource Planning, Costing and Pricing, Expert Witness Testimony, Revenue Requirements, Class Cost of Service, Rate Design, Statistics, Valuation, Market Studies, Rate & Regulatory Case Management, Resource Adequacy, Load Normalization and Forecasting, Strategic Business Planning.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES

California Public Utilities Commission

Idaho Public Utilities Commission

Kansas Corporation Commission

Michigan Public Service Commission

Missouri Public Service Commission

New Hampshire Public Utilities Commission

New Mexico Public Regulation Commission

Public Utilities Commission of Nevada

Public Service Commission of Wisconsin

Wyoming Public Service Commission

Federal Energy Regulatory Commission

REPRESENTATIVE EXPERIENCE

RESOURCE PLANNING

Mr. Phillips has worked on numerous resource planning projects related to utility resource planning, procurement, and asset retirement issues. Specifically, he has:

- Developed two Integrated Resource Plans (2020 & 2023) for Public Service Company of New Mexico.
- Developed resource planning analysis (economic and resource adequacy) in support for the abandonment/exit from two coal plants, as well as in support of multiple gas, renewable and storage assets.
- Oversaw the development and evaluations of [9] Requests for Proposals ("RFPs") seeking supply and demand side resources. These evaluations resulted in approximately 2.5 GW of requested resource approvals, and half of the evaluations were conducted under the oversight of Independent Evaluators. Mr. Phillips lead commercial negotiations for [4] of the approved projects.
- Worked with software vendors and internal stakeholders to improve cross functional planning process between generation and transmission.

- Reviewed resource planning analysis developed by utilities to ensure the proposed assets (gas and renewable resources) were the lowest reasonable cost alternatives.
- Review utility IRP's and prepares fundamental based resource planning analysis to forecast utility cost of service.

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Phillips has worked on numerous rate cases helping to prepare and review revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America (both embedded and marginal cost studies) and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Work in conjunction with the utility pricing group to develop and propose a new class cost of service allocation method for systems with significant renewable penetration.
- Review WNA/RNA mechanisms for a utility including back casting results.
- Supported the development of time of use rates, demand rates, economic development rates, and load retention rates.
- Supported lead-lag analyses.
- Prepared load forecasts and analyzed customer usage profiles used for planning and ratemaking.
- Developed exit fee calculations in support of customers seeking to access electric supply form an alternative supplier.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Phillips has testified in several cases on resource planning, class cost of service studies and numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on new resource acquisitions and resource requirements and integrated resource plans.
- Filed testimony as an expert witness on allocated class cost of service studies (both embedded and marginal cost studies).
- Filed testimony as an expert witness discussing potential changes necessary to align cost allocation with cost causation as utilities decarbonize their systems.
- Filed testimony as an expert witness on the application of statistical analysis.

- Filed testimony as an expert witness on the application of retail open access and the proper exit fees / protection necessary to balance the interests of the utility, retail customers and the applicant seeking alternative retail supply.
- Filed testimony as an expert on utility avoided costs, energy efficiency and renewable portfolio standard compliance.
- Filed testimony as an expert on production cost simulation estimates for fuel and purchase power costs and methods for estimated off-system sales margins.

SPEAKING EXPERIENCE

- Wholesale Electric Power Markets and Transmission, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2013
- Power Markets and Natural Gas Markets, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2013 & 2014
- Energy Market Economics, BAI Annual Seminar: Utility Ratemaking Fundamentals, St. Louis MO, 2015 & 2016
- PNM 2020 IRP Public Advisory Meetings, Multiple Topics/Multiple Meetings, Albuquerque NM, 2019 - 2021 https://www.pnmforwardtogether.com/presentations
- PNMR Board of Directors, October 2020, Resource Adequacy in deep carbonization
- Rocky Mountain Mineral Law Foundation, March 2021, Benefits and Concerns Integrating Energy Storage on Utility Systems
- Sandia National Labs, March 2021, New Mexico Energy Transition Act
- Numerous Internal Presentation to PNM Departments
- Community Solar Working Group, October 2020, Integrating Solar on PNM's System
- EPRI, February 2021, Hybrid Solar-Storage
- EUCI, October 2020, Properly Reflecting Coal Plant Retirements in IRP
- EUCI, May 2021, Resource Adequacy Planning in IRP
- Iowa State, April 2020, Integrated Resource Planning
- EUCI, February 2022, De-carbonization: Modeling Options and Limitations in IRP
- New Mexico Governors Economic Development Forum, September 2022, Clean Energy Impact on Economic Development Opportunities
- SolarPACES, September 2022, Concentrating Solar Power in the Energy Transition
- Nextera Energy Storage in the West, October 2022, Utility Perspective of Storage Operations in Bilateral Markets
- DOE Energy Storage Conference, October 2022, Utility Perspective on the Grid of the Future

- Sandia Nation Labs, October 2022, How to Accelerate the Energy Transition in New Mexico
- New Mexico Renewable Transmission Authority, October 2022, The Role of Storage in Utility Reliability
- National Black Caucus of State legislators, November 2022, Grid Resiliency and Reliability Considerations in a Renewable Grid
- Leadership Sandoval, February 2023, New Mexico's Energy Transition
- Water and Energy Conversation Coalition, March 2023, Challenges in Decarbonization.
- EUCI, April 2023, Integrated Resource Panning – Resource Adequacy Planning in a Heavy Renewable Energy / Deeply Decarbonized Grid

SOFTWARE AND ANALYTICS

- Proficient in MATLAB, R & Python programming
- Proficient with MS Excel, VBA & Solver
- Proficient with Gurobi and CPLEX Optimization Solvers and other open source optimization platforms
- Proficient with EnCompass resource planning and production cost model
- Proficient with SERVM stochastic reliability and production cost model
- Proficient with SQL
- Experience with C/C++ programming
- Experience with PSS/E Power Flow Simulator
- Experience with Ventyx Strategist Resource Planning Model and PROMOD Production Cost Model
- Experience with RealTime Production Cost Model
- Experience with PLEXOS Integrated Energy Model
- Statistical Analysis, Forecasting, Risk Models & Monte Carlo Simulation Methods

Line No.	Line Item	Units of Measure	System A	System B	System B-2	Description / Notes
	System Characteristics					
1	System Peak Demand	kW	1,000,000	1,000,000	1,000,000	Input Assumption
2	System Load Factor	%	55%	55%	55%	Input Assumption
3	System 12 CP	kW	10,800,000	10,800,000	10,800,000	Assume 90% Coincidence Factor
4	System Energy	kWh	4,818,000,000	4,818,000,000	4,818,000,000	Line 1 * Line 2 * 8,760
5	Planning Reserve Margin	%	15%	15%	15%	Input Assumption
6	**Traditional Resource Characteristics**					
7	Fixed/Demand Cost	$	$200,000,000	$111,521,739	$111,521,739	Per Unit Cost Held Constant
8	Variable/Energy Cost	$	$200,000,000	$40,000,000	$40,000,000	Per Unit Cost Held Constant
9	Firm Capacity	kW	1,150,000	641,250	641,250	Assume 100% Firm
10	Installed Capacity	kW	1,150,000	641,250	641,250	System A: Line 1 * (1 + Line 5), System B: System A Line 9 - System B Line 15
11	Energy Produced	kWh	4,818,000,000	963,600,000	963,600,000	System A: Set equal to Line 4, System B: System A Line 11 - System B Line 17
12	**Renewable Resource Characteristics**					
13	Fixed/Demand Cost	$	$0.00	$248,478,261	$91,936,957	Set such that sum of renewable and traditional cost sum to total System A costs
14	Variable/Energy Cost	$	$0.00	$0.00	$156,541,304	System B-2: (1-37%) * System B Line 13
15	Firm Capacity	kW	0	508,750	508,750	Assumes 37% Firm Capacity / ELCC
16	Installed Capacity	kW	0	1,375,000	1,375,000	Assumes 32% Capacity Factor
17	Energy Produced	kWh	0	3,854,400,000	3,854,400,000	Renewable set to 80% of System Energy
	Class Load Characteristics					
18	Residential Class					
19	12 CP	kW	5,400,000	5,400,000	5,400,000	Assume 50% of System
20	Energy	kWh	1,927,200,000	1,927,200,000	1,927,200,000	Assume 40% of System
21	Commercial Class					
22	12 CP	kW	3,240,000	3,240,000	3,240,000	Assume 30% of System
23	Energy	kWh	1,204,500,000	1,204,500,000	1,204,500,000	Assume 25% of System
24	Industrial Class					
25	12 CP	kW	2,160,000	2,160,000	2,160,000	Assume 20% of System
26	Energy	kWh	1,686,300,000	1,686,300,000	1,686,300,000	Assume 35% of System
27	**Allocations**					
28	Residential					
29	Demand	$	$100,000,000	$180,000,000	$101,729,348	Line 19 / Line 3 * (Line 7 + Line 13)
30	Energy	$	$80,000,000	$16,000,000	$78,616,522	Line 20 / Line 4 * (Line 8 + Line 14)
31	**Total**	$	$180,000,000	$196,000,000	$180,345,870	Line 29 + Line 30
32	Commercial					
33	Demand	$	$60,000,000	$108,000,000	$61,037,609	Line 22 / Line 3 * (Line 7 + Line 13)
34	Energy	$	$50,000,000	$10,000,000	$49,135,326	Line 23 / Line 4 * (Line 8 + Line 14)
35	**Total**	$	$110,000,000	$118,000,000	$110,172,935	Line 33 + Line 34
36	Industrial					
37	Demand	$	$40,000,000	$72,000,000	$40,691,739	Line 25 / Line 3 * (Line 7 + Line 13)
38	Energy	$	$70,000,000	$14,000,000	$68,789,457	Line 26 / Line 4 * (Line 8 + Line 14)
39	**Total**	$	$110,000,000	$86,000,000	$109,481,196	Line 37 + Line 38

2026 Net Plant in Service Allocation Analysis

Line No.	Description	Net Plant in Service	1/13th Energy Allocation	25% Energy Allocation	Assign Increase from 25% Allocation of 1/13th Allocation to Solar	Percent Energy Weighted	Percent Demand Weighted
1	Steam, Nuclear and Gas Plant	$ 21,656,470,199	$ 1,665,882,323		$ 1,665,882,323	7.69%	92.31%
2	Solar Plant	$ 10,500,814,048	$ 807,754,927		$ 6,619,061,206	63.03%	36.97%
3	Energy Storage Plant	$ 1,419,152,031	$ 109,165,541		$ 109,165,541	7.69%	92.31%
4	Total Production	$ 33,576,436,278	$ 2,582,802,791	$ 8,394,109,070	$ 8,394,109,070	25%	
5	Increase in Energy weight			$ 5,811,306,279			

2027 Net Plant in Service Allocation Analysis

Line No.	Description	Net Plant in Service	1/13th Energy Allocation	25% Energy Allocation	Assign Increase from 25% Allocation of 1/13th Allocation to Solar	Percent Energy Weighted	Percent Demand Weighted
1	Steam, Nuclear and Gas Plant	$ 24,827,041,848	$ 1,909,772,450		$ 1,909,772,450	7.69%	92.31%
2	Solar Plant	$ 11,272,831,402	$ 867,140,877		$ 7,174,346,784	63.64%	36.36%
3	Energy Storage Plant	$ 341,760,879	$ 26,289,298		$ 26,289,298	7.69%	92.31%
4	Total Production	$ 36,441,634,129	$ 2,803,202,625	$ 9,110,408,532	$ 9,110,408,532	25%	
5	Increase in Energy weight			$ 6,307,205,907			