

**GOVERNMENT OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU**

IN RE: PUERTO RICO ELECTRIC POWER
AUTHORITY RATE REVIEW

CASE NO.: NEPR-AP-2023-0003

SUBJECT: Hearing Examiner's Order
Submitting Expert Reports of Energy Bureau
Consultants

Hearing Examiner's Order Submitting Expert Reports of Energy Bureau Consultants

Per the process established by my order of October 1, 2025, this Order marks for identification, to be admitted into evidence subject to objections, the following documents:

- PREB Consultants 59, Revenue Decoupling Expert Report of Melissa Whited
- PREB Consultants 61, Expert Report of Zachary Ming on Billing Determinants, Cost Allocation, and Rate Design
- PREB Consultants 62, Expert Report of Ralph Smith and Mark Dady on Overall Revenue Requirement

I direct Secretary Seda to place these reports on the Energy Bureau's case docket.

Be notified and published.



Scott Hempling
Hearing Examiner

CERTIFICATION

I certify that the Hearing Examiner, Scott Hempling, has so established on October 6, 2025. I also certify that on October 6, 2025, I have proceeded with the filing of the Order, and a copy was notified by electronic mail to: mvalle@gmlex.net; arivera@gmlex.net; jmartinez@gmlex.net; jgonzalez@gmlex.net; nzayas@gmlex.net; Gerard.Gil@ankura.com; Jorge.SanMiguel@ankura.com; Lucas.Porter@ankura.com; mdiconza@omm.com; golivera@omm.com; pfriedman@omm.com; msyassin@omm.com; msyassin@omm.com; katuska.bolanos-lugo@us.dlapiper.com; Yahaira.delarosa@us.dlapiper.com; margarita.mercado@us.dlapiper.com; carolyn.clarkin@us.dlapiper.com; andrea.chambers@us.dlapiper.com; regulatory@genera-pr.com; legal@genera-pr.com; mvazquez@vvlawpr.com; gvilanova@vvlawpr.com; ratecase@genera-pr.com;

jfr@sbgblaw.com; hriviera@jrsp.pr.gov; gerardo_cosme@solartekpr.net;
contratistas@jrsp.pr.gov; victorluisgonzalez@yahoo.com; Cfl@mcvpr.com;
nancy@emmanuelli.law; jrinconlopez@guidehouse.com; Josh.Llamas@fticonsulting.com;
Anu.Sen@fticonsulting.com; Ellen.Smith@fticonsulting.com; Intisarul.Islam@weil.com;
alexis.ramsey@weil.com; kara.smith@weil.com; rafael.ortiz.mendoza@gmail.com;
rolando@emmanuelli.law; monica@emmanuelli.law; cristian@emmanuelli.law;
lgnq2021@gmail.com; jan.albinolopez@us.dlapiper.com;
Rachel.Albanese@us.dlapiper.com; varoon.sachdev@whitecase.com; javrua@sesapr.org;
Brett.ingerman@us.dlapiper.com; brett.solberg@us.dlapiper.com;
agraitfe@agraitlawpr.com; jpouroman@outlook.com; epo@amgprlaw.com;
loliver@amgprlaw.com; acasellas@amgprlaw.com; matt.barr@weil.com;
Robert.berezin@weil.com; Gabriel.morgan@weil.com; corey.bradley@weil.com;
lramos@ramoscruzlegal.com; tlauria@whitecase.com; gkurtz@whitecase.com;
ccolumbres@whitecase.com; isaac.glassman@whitecase.com; tmacwright@whitecase.com;
jcunningham@whitecase.com; mshepherd@whitecase.com; jgreen@whitecase.com;
hburgos@cabprlaw.com; dperez@cabprlaw.com; howard.hawkins@cwt.com;
mark.ellenberg@cwt.com; casey.servais@cwt.com; bill.natbony@cwt.com;
zack.schrieber@cwt.com; thomas.curtin@cwt.com; escalera@reichardescalera.com;
riverac@reichardescalera.com; susheelkirpalani@quinnemanuel.com;
erickay@quinnemanuel.com; dmonserrate@msglawpr.com; fgierbolini@msglawpr.com;
rschell@msglawpr.com; eric.brunstad@dechert.com; Stephen.zide@dechert.com;
David.herman@dechert.com; Isaac.Stevens@dechert.com; James.Moser@dechert.com;
michael.doluisio@dechert.com; Kayla.Yoon@dechert.com; Julia@londoneconomics.com;
Brian@londoneconomics.com; luke@londoneconomics.com; juan@londoneconomics.com;
mmcgill@gibsondunn.com; LShelfer@gibsondunn.com; jcasillas@cstlawpr.com;
jnieves@cstlawpr.com; pedrojimenez@paulhastings.com; ericstolze@paulhastings.com;
arrivera@nuenergypr.com; apc@mcvpr.com; ramonluisnieves@rlnlegal.com.

I sign this in San Juan, Puerto Rico, on October 6, 2025.




Sonia Seda Gaztambide
Clerk

**BEFORE THE
PUERTO RICO ENERGY BUREAU**

_____	)	CASE NO: NEPR-AP-2023-0003
IN RE: PUERTO RICO ELECTRIC	)	
POWER AUTHORITY RATE REVIEW	)	SUBJECT: REVENUE
_____	)	DECOUPLING

**Expert Report of
Melissa Whited**

Synapse Energy Economics, Inc.

October 6, 2025

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Exhibit 59.1: Responses to ROIs

Exhibit 59.2: Curriculum Vitae of Melissa Whited

EXECUTIVE SUMMARY

The purpose of this report is to evaluate LUMA's revenue decoupling proposal, to explain the basics of revenue decoupling, and to make recommendations.

Revenue decoupling severs the direct link between utility sales and revenues. Traditional ratemaking ties revenues to projected sales. This tie creates revenue volatility and gives utilities that profit from sales incentives to encourage consumption while avoiding efficiency programs or distributed generation. A decoupling mechanism avoids these problems by reconciling actual revenues with the revenue requirement authorized by the regulator. When revenues fall short of the authorized level, the mechanism applies surcharges; when revenues exceed the authorized level, the mechanism credits customers. This process stabilizes revenues and aligns recovery more closely with costs.

LUMA filed a proposal for a revenue decoupling mechanism in response to the Puerto Rico Energy Bureau of the Public Service Regulatory Board's (PREB) February 27, 2025, Resolution and Order. LUMA's initial proposal did not specify key elements such as the customer classes included, the frequency of adjustments, whether adjustments would operate in both directions, or how the mechanism would treat outage-related losses. In discovery, LUMA confirmed its intent to include sales lost due to outages.

While the Solar and Energy Storage Association (SESA) supports the concept of decoupling, it finds LUMA's incomplete proposal problematic. In addition, SESA objected to including outage-related sales in the decoupling mechanism, arguing that this treatment would weaken accountability for reliability. SESA also argued that revenue decoupling makes higher fixed charges unnecessary. SESA Witness E. Kyle Datta outlined recommendations for a complete decoupling framework, including full documentation, bidirectional adjustments, quarterly accruals, exclusions for fuel and pass-through riders, transparency, audits, and performance incentives tied to service quality.

A revenue decoupling mechanism must specify key design parameters. Establishing the revenue target requires choosing among per-customer, per-class, or systemwide benchmarks, each with trade-offs in precision, volatility, and administrative burden. Weather normalization introduces complexity but isolates non-weather drivers, while full decoupling increases transparency but shifts weather-related risk to customers. Coverage across customer classes determines how broadly the mechanism spreads adjustments and how it handles small classes. The frequency of adjustments affects both bill stability and administrative effort. Bidirectional versus one-way adjustments balance customer affordability against system investment. Caps on adjustments limit bill shocks but can defer recovery. Implementation through a rider creates timely, visible adjustments, while deferral accounting delays reconciliation. This report discusses the various trade-offs associated with these design decisions and provides my recommendations regarding implementation of a decoupling mechanism in Puerto Rico.

LUMA's proposed revenue decoupling mechanism would provide revenue certainty and ensure that LUMA and Genera, as operators of the Puerto Rico Electric Power Authority (PREPA), can adequately fund necessary power system investments, regardless of changes in electricity sales. However, LUMA's filing lacks critical details. To address this gap and ensure that the decoupling mechanism is implemented in a manner that is in the public interest, I recommend that PREB:

1. Base the decoupling revenue target on the total utility revenue requirement¹ across all customer classes. A single systemwide target will reduce rate volatility, avoid disproportionate impacts on small classes, and simplify administration.
2. Exclude variable costs, such as fuel and purchased power, from the decoupling formula because separate riders already reconcile those costs.
3. Implement *full decoupling* without weather normalization to improve transparency and reduce complexity.
4. Require annual decoupling adjustments to limit administrative burden and avoid substantial rate volatility, while still providing timely revenue recovery.
5. Require that the mechanism operate in both directions, with surcharges when revenues fall short of the authorized amount and refunds when revenues exceed it.
6. Establish a soft cap on upward adjustments equal to 3 percent of annual revenues subject to the decoupling mechanism, while placing no cap on downward adjustments (refunds).
7. Require implementation of the decoupling mechanism through a rider rather than through deferral accounting to promote timely, transparent reconciliation of revenues, support stable utility cash flow, and avoid large accumulated balances.
8. Include sales lost due to outages in the decoupling calculation. PREB should address reliability and performance accountability through separate incentive mechanisms.
9. Require LUMA to file a complete description of the decoupling mechanism before implementation, including formulas, inputs, data sources, and workpapers. This should be filed within 30 days of the Commission's decision and order in this case. Any comments

¹ The total utility revenue requirement includes the revenue requirements for LUMA's operation of the transmission and distribution system and Genera's operation of generation resources.

on the compliance filing should be filed within 20 days of the date of the compliance filing.

10. Require LUMA to submit updated calculations and workpapers annually when requesting adjustments to the rider and provide stakeholders with an opportunity to review these filings, conduct discovery, and submit comments before PREB approves adjustments.
11. Conduct a thorough review of the pilot decoupling mechanism during the next base rate case.

I. BACKGROUND

My name is Melissa Whited. I am a Vice President at Synapse Energy Economics (Synapse) and a consultant to the Puerto Rico Energy Bureau of the Public Service Regulatory Board (PREB). I have 13 years of experience in economic research and utility regulation. At Synapse, my work has focused extensively on regulatory models, ratemaking policy, and rate design.

I have sponsored testimony before thirteen state and provincial regulatory commissions and have served as an invited speaker at numerous industry conferences, including the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at both the 2021 Winter Policy Summit and the 2018 Annual Meeting. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin–Madison. My curriculum vitae is attached as Exhibit 59.2.

The purpose of this report is to evaluate LUMA’s revenue decoupling proposal filed in response to PREB’s February 27, 2025 Resolution and Order. My analysis addresses (1) the regulatory context for revenue decoupling, (2) LUMA’s proposal, (3) positions of other parties, (4) key considerations in the design of a revenue decoupling mechanism, and (5) my recommendations for implementing revenue decoupling in Puerto Rico.

A. Revenue decoupling overview

Under standard ratemaking—meaning, ratemaking without revenue decoupling—the rates set by a regulator in a base rate case remain fixed until the next base rate case. The regulator establishes those rates based on sales projections. Under this approach, any change in sales between rate cases causes the utility’s revenues to increase or decrease, depending on whether the actual sales exceed or fall below the projections. This approach makes revenue unpredictable. It also induces the utility to take actions that increase electricity sales (thereby increasing revenues), while avoiding actions that would reduce electricity sales, such as energy efficiency or distributed generation.

Revenue decoupling addresses this problem by severing the direct link between sales and revenues. Under a decoupling mechanism, the utility recovers its authorized revenue requirement independently of fluctuations in customer electricity use. If actual revenues fall short of the authorized amount (e.g., due to weather, economic conditions, energy efficiency measures, or customer-owned generation), the regulator applies a surcharge to customer bills to produce the missing revenues. Conversely, if revenues exceed the authorized level (e.g., due to higher-than-expected sales from weather or economic growth), customers receive a bill credit. The decoupling mechanism produces these adjustments through a transparent, formula-based process on an annual or monthly basis.

Revenue decoupling neither guarantees profits nor automatically increases rates. Instead, it provides stability and predictability in utility revenues and ensures that cost recovery aligns more closely with actual expenditures.

B. PREB order

On February 27, 2025, PREB issued a resolution and order in which it established a requirement for LUMA to file a proposal for a temporary revenue decoupling mechanism. The order specified that LUMA’s decoupling proposal should:

- provide for at least semi-annual reconciliations;
- allow PREB to review adjustments both before they take effect and after the period in which they were in effect, in case a reconciliation is needed; and
- allow PREB to review the mechanism itself prior to Fiscal Years 2027 and 2028.²

C. LUMA’s decoupling proposal

On June 30, 2025, LUMA submitted its rate case filing, including a proposal for a revenue decoupling mechanism. In its filing, LUMA proposed that PREB approve a revenue decoupling mechanism for the Puerto Rico Electric Power Authority (PREPA) beginning in Fiscal Year 2028 and reconciling revenues beginning with Fiscal Year 2027.

LUMA Witness Sam Shannon described the decoupling mechanism as a tool to “true-up” the utility’s revenue for non-weather-related deviations in sales through a decoupling rider.³ Mr. Shannon argued that implementing a decoupling mechanism would protect the utility’s financial position from reductions in sales beyond what is already included in the forecasts presented in this rate case.⁴ In response to discovery, LUMA also noted that credit rating agencies view revenue decoupling mechanisms positively because they reduce utility revenue volatility, but claimed that it cannot determine the extent to which a decoupling mechanism would impact

² PREB. Resolution and Order Adding Two Filing Requirements. Case No. NEPR-AP-2023-0003. February 27, 2025. Available at: <https://energia.pr.gov/wp-content/uploads/sites/7/2025/02/20250227-AP20230003-Resolution-and-Order.pdf>.

³ LUMA Exhibit 20.00, p. 30.

⁴ LUMA Exhibit 20.00, p. 31.

PREPA's ability to access capital markets on favorable terms because "the conditions under which PREPA would exit Title III bankruptcy are not known or defined at this point in time."⁵

LUMA's filing lacks critical details regarding other aspects of how the decoupling mechanism would function. For example, Mr. Shannon's testimony did not specify which rate classes the decoupling mechanism would apply to, how frequently the adjustments would occur, whether the mechanism would be bidirectional (applying equally when sales exceed forecasts as well as when sales fall below forecasts), or how the mechanism would treat sales reductions attributable to power outages. In response to discovery, LUMA clarified its position that reduced sales resulting from power outages should be included in the revenue decoupling mechanism, to ensure that LUMA and Genera, operators of PREPA, have adequate revenue to invest in the system to prevent future outages.⁶

D. Other parties' positions

On September 8, 2025, the Solar and Energy Storage Association (SESA) filed testimony of E. Kyle Datta that addressed revenue decoupling, as well as other issues. While SESA supports the concept of revenue decoupling, Mr. Datta testified that he could not support the decoupling mechanism as proposed by LUMA, in part because "it is not clear what LUMA is proposing."⁷ Instead, Mr. Datta recommended that the Energy Bureau not approve decoupling until LUMA submits a complete, transparent proposal that intervenors can evaluate.

SESA further objected to LUMA's proposal because it would compensate LUMA for lost revenues associated with power outages, which Mr. Datta contended would "absolve LUMA management of any responsibility or repercussions from failures due to poor management of the grid" and be construed as disregard for the welfare of the people of Puerto Rico.⁸ Finally, Mr. Datta argued that if PREB adopts a revenue decoupling mechanism, it should reject higher fixed charges since decoupling already provides revenue certainty.⁹

In his testimony, Mr. Datta recommended that PREB approve a decoupling mechanism that¹⁰

⁵ Response PC-of-LUMA-DECOUP-13.

⁶ Response PC-of-LUMA-DECOUP-4.

⁷ Testimony of E. Kyle Datta on behalf of Solar and Energy Storage Association. Case No. NEPR-AP-2023-0003. September 8, 2025, p. 36.

⁸ *Id.*, p. 37.

⁹ Datta Direct Testimony pp. 36-38.

¹⁰ *Id.*

- is fully documented, with supporting tariff and calculation handbooks that include targets, formulas, and data;
- is bidirectional, with symmetric true-ups to account for over/under-collections, and with deadbands and caps on annual adjustments;
- accounts for both weather-related and non-weather-related deviations in sales;
- uses a per-customer or normalized targets to avoid windfalls from load migration;
- applies only to LUMA base distribution costs and excludes all fuel and other pass-through riders;
- prohibits inclusion of sales lost from utility-caused outages;
- uses quarterly accrual mechanisms with annual resets;
- employs deadbands and caps to smooth bills;
- is transparent and is subject to audit; LUMA should publish its workpapers, PREB should allow discovery, and the mechanism should be subject to independent annual audits; and
- is paired with LUMA performance incentives for utility service quality metrics and penalties, linked or in addition to LUMA contract.

II. KEY DECOUPLING DESIGN CONSIDERATIONS

In evaluating the proper decoupling design for Puerto Rico, PREB must consider several core issues involving both technical choices and policy trade-offs that will shape how the mechanism balances revenue stability, customer affordability, and administrative feasibility. Below I discuss nine important design and implementation considerations, noting the advantages and disadvantages of each.

A. Revenue target

To implement decoupling, PREB must first decide how to set the utility's revenue targets. The revenue target is the benchmark against which regulators compare actual revenues to determine

whether the utility over- or under-collected.¹¹ Because decoupling seeks to provide a set amount of revenue regardless of sales, regulators typically exclude from the decoupling mechanism costs that fluctuate with sales. In particular, regulators generally exclude variable costs, such as fuel and purchased power, from the decoupling calculation. Likewise, to avoid duplication, regulators exclude costs that are already trued up through other mechanisms. In response to discovery, LUMA appears to concur with this approach, stating that “fuel and purchased power would not need to be included because the Fuel Charge Adjustment (FCA) and Purchased Power Charge Adjustment (PPCA) rider formulas already contain their own reconciliation mechanisms.”¹²

There are several approaches to establishing decoupling revenue targets:

- A *revenue-per-customer target* establishes a set amount of revenue per customer. Setting target revenues on a per-customer basis accounts for customer growth or decline, recognizing that utility revenue requirements tend to be driven, in part, by the number of customers served. The advantage of this approach is that, if the number of customers grows rapidly, it provides for additional revenues. A disadvantage of the revenue-per-customer approach is that revenues would decline if the number of customers declines, even though it is unlikely that costs would decline in a commensurate manner since many utility costs are fixed in the near-term.
- A *per-class target* specifies the total revenue per class, regardless of the number of customers. Setting the revenue target separately for each class ensures that the utility can recover the revenue requirement for each class approved in its most recent rate case and is therefore the most accurate in terms of collecting costs from the customer classes who caused the cost to be incurred. However, separate decoupling revenue targets for each class can lead to rate volatility in classes with very few customers if one or more customers depart, due to the revenue being reallocated across a smaller group of customers. For this reason, regulators sometimes exclude customer classes with very few customers to avoid extreme swings in rates if a single large customer leaves the system.¹³ In response to a request of information (ROI), LUMA also contended that per-class

¹¹ The revenue target is the approved annual revenue requirement. It can also be expressed as a monthly revenue target based on expected monthly sales.

¹² Response to PC-of-LUMA-DECOUP-3.

¹³ LUMA also argued that a benefit of exempting certain customer classes is that it reduces inter-class cross-subsidies by exempting classes whose usage is less impacted by the policy drivers of the decoupling mechanism. Response to PC-of-LUMA-DECOUP-9.

targets impose more administrative costs and may be more difficult for customers to understand versus a single revenue target for the entire utility.¹⁴

- A *total revenue requirement target* offers administrative simplicity by using a single systemwide figure. Using a total systemwide revenue target also tends to smooth rate adjustments since the customer base is large. However, a system-wide revenue requirement approach socializes revenue differences across all customers, which may create cross-subsidization between classes.

I recommend that PREB approve a decoupling mechanism based on the utility's total revenue requirement target for all customer classes.¹⁵ Adopting a total revenue target will help ensure that LUMA and Genera, on behalf of PREPA, recover the utility's approved revenue without risking substantial rate impacts on any single class. Any cross-subsidies resulting from this approach will be minimal if annual rate adjustments are capped at 3 percent of the base revenue requirement, particularly since base rates currently only constitute approximately 26 percent of the total average customer bill, with the remainder being comprised mostly of variable costs recovered through riders.¹⁶

B. Weather normalization

Another important design choice is whether to normalize sales for weather before applying the decoupling formula. The objective of weather normalization is to determine what sales would have been under typical or "normal" weather conditions by using a statistical analysis to remove the variance in actual electricity consumption that is due to weather fluctuations.

Under "full decoupling," sales volumes are not weather-normalized. Instead, full decoupling adjusts rates solely to ensure that the utility recovers only its pre-determined revenue target. For example, if weather is hotter than normal (leading to higher sales), the decoupling mechanism would reduce rates because the utility recovered more revenues than its revenue target.

A "partial decoupling" approach converts actual sales into weather-normalized values, typically through regression analysis, and then compares those normalized values to the authorized (weather-normalized) target. This method isolates non-weather-related sales changes but introduces complexity and requires ongoing modeling of what the weather-normalized sales would have been.

¹⁴ Response to PC-of-LUMA-DECOUP-10.

¹⁵ The total utility revenue requirement includes the revenue requirements for LUMA's operation of the transmission and distribution system and Genera's operation of generation resources.

¹⁶ LUMA Exhibit 1.04, page 1.

The decision to weather-normalize sales depends largely on whether the decoupling mechanism applies to the utility's variable costs as well as its fixed costs:

- If the decoupling mechanism includes variable costs (such as fuel and purchased power), then weather normalization (partial decoupling) is more appropriate. This is because the target revenue requirement (including variable costs) assumes a “normal” level of sales. If actual sales are higher due to hotter-than-normal weather, then variable costs will also be higher. Weather normalizing removes the effect of temperature variations on sales, which allows the utility to retain more revenues to cover its higher variable costs.
- Full decoupling (i.e., without weather normalization), is appropriate if variable costs are excluded from the decoupling mechanism. In this case, the revenue target would only apply to fixed costs, which do not vary with sales. Thus, if sales increase due to hotter-than-normal weather, the utility would over-recover its fixed costs, and the decoupling mechanism would return the excess revenues to ratepayers. Full decoupling is also more transparent and simpler to administer than partial decoupling.

I recommend that PREB approve a full revenue decoupling mechanism that applies only to fixed costs recovered through base rates. (Variable costs, such as fuel and purchased power costs, are already recovered through riders, which pass through these costs directly to customers.¹⁷) It is reasonable for PREB to adopt a full decoupling mechanism (i.e., one that also controls for weather variability) because the utility's fixed costs do not change based on weather. Thus, the decoupling mechanism should collect the approved base revenue requirement—no more and no less—regardless of weather-related changes in electricity sales.

C. Rate adjustment frequency

Another design choice is the frequency of decoupling adjustments. More frequent reconciliations, such as quarterly, reduce customer bill volatility because each adjustment reflects a shorter period and therefore smaller deviations. At the same time, frequent adjustments require more time from utility and regulatory staff time due to the number of adjustments required, as well as the need to establish monthly or quarterly revenue targets. In response to an ROI, LUMA asserted that “the simplest approach would be an annual adjustment because it would incorporate seasonal variations and be administratively easier to implement.”¹⁸

¹⁷ For example, LUMA's recalculated reconciliation factors for the FCA and PPCA were filed in Case No. NEPR-MI-2020-0001 on July 15, 2025.

¹⁸ Response to PC-of-LUMA-DECOUP-2.

I recommend that PREB adopt LUMA’s proposal for annual decoupling adjustments because it will smooth out seasonal variations and will be simpler to review and implement.

D. Bidirectional versus one-way adjustments

A bidirectional mechanism requires the utility to return any over-collections to customers through credits, as well as to recover under-collections through surcharges. A bidirectional approach ensures that customers share equally in both upward and downward adjustments. A one-way mechanism, by contrast, only allows recovery of under-collections. While one-way mechanisms might channel excess collections into electric system improvements,¹⁹ it also raises concerns about affordability and fairness for customers. That is, customers bear the risk that they will face an upward rate adjustment if revenues fall short of the approved revenue requirement but do not receive any refund if the utility collects more revenues than approved.

I recommend that PREB approve a bidirectional decoupling mechanism so that any revenues collected in excess of the approved revenue requirement are returned to customers. While it is important to ensure that the utility collects its allowed revenue requirement, it is critical that PREB also strive to ensure electric rates are affordable.

E. Caps on adjustments

Another design feature involves whether to cap the size of annual decoupling adjustments. A soft cap, which limits increases to a set percentage (for example, 3 percent) but imposes no limit on decreases, provides customers with protection from sudden bill spikes. However, caps also restrict the utility’s ability to fully recover authorized revenues, which can lead to deferred balances that complicate future reconciliations.

I recommend that PREB approve a revenue decoupling mechanism with a soft cap on upward rate adjustments and no cap on downward adjustments (refunds). I recommend that PREB set this cap at 3 percent of annual revenues subject to the decoupling mechanism.²⁰ The utility would defer any under-recovery of revenues beyond the cap for potential recovery in subsequent decoupling adjustments. Deferred amounts would be rolled over from year to year until fully recovered through the decoupling adjustments or addressed in the next rate case.

¹⁹ In response to PC-of-LUMA-DECOUP-7, LUMA noted that a drawback of a bidirectional mechanism “may be that an increase in revenues would not be reinvested in the electric system in Puerto Rico.”

²⁰ A three percent cap has been adopted in several other jurisdictions, including Oregon, Minnesota, Massachusetts, and Idaho.

I recommend the cap on upward decoupling adjustments for two reasons: 1) to guard against potentially large customer bill increases, and 2) because persistent under-recoveries in excess of the cap may signal that other factors have changed substantially, requiring additional regulatory review.

F. Collection mechanism

PREB must choose how to implement the decoupling mechanism once it calculates the adjustment. One option involves creating a separate rider that directly collects or refunds amounts on customer bills. A rider provides clarity and immediacy, but it may require LUMA to upgrade its billing systems, which could create additional costs not included in its current revenue requirement.²¹ The alternative approach involves deferral accounting, in which the utility records under- or over-collections and nets them against the revenue requirement in the next base rate case. This option reduces immediate administrative costs but delays reconciliations. If reconciliations are expected to be small, this delay is unlikely to impact customers significantly.

I recommend that PREB approve a rider for recovery (or refund) of under- and over-collections, rather than using deferral accounting. Riders allow revenue differences to be reconciled quickly, which keeps the utility's cash flow more stable and reduces the size of over- or under-collections. Deferral accounting, by contrast, can cause a large balance to accumulate over several years, leading to a large rate increase in the following rate case, and negatively impacting the utility's cash available for operations. My recommendation would be to only defer balances in excess of the 3 percent cap, as this would help to ensure that any accrued balances are relatively small compared to deferring all under-collections to the next rate case.

G. Treatment of power outages

Finally, PREB must determine how the mechanism will treat sales losses that occur because of power outages. SESA argued that PREB should exclude outage-related losses to ensure accountability for grid reliability. In Puerto Rico, however, LUMA receives compensation through its management contract, not through volumetric sales. As a result, decoupling does not insulate LUMA from the financial consequences of poor performance. Instead, excluding outage-related sales would deprive the utility of necessary revenues for maintenance and investment, which would ultimately harm customers by undermining system reliability. A more direct way to address performance incentives is to partially condition LUMA's compensation on

²¹ In response to PC-of-LUMA-DECOUP-5, LUMA states "Funding to support the design and implementation of such mechanism within LUMA's billing system is currently not contemplated in LUMA's rate review proposal."

reliability. I therefore do not agree with SESA's position that outages should be excluded from the decoupling mechanism.

H. Interactions with rate design

Where revenue certainty is a concern, some regulators have approved requests to shift revenue recovery away from volumetric rates and more toward fixed charges. SESA argued that PREB should reject LUMA's proposal to adopt higher fixed charges, since revenue decoupling would make higher fixed charges unnecessary to provide revenue stability. LUMA argued that its proposal for higher fixed charges is not impacted by revenue decoupling, since the fixed charges are meant to reflect the customer-classified costs.²² These issues are addressed more fully by PREB's consultant E3 in PC Exhibit 61.

I. Review of decoupling mechanism

SESA's witness Mr. Datta testified that it is important that the decoupling mechanism be clearly defined, calculations are transparent, and stakeholders are afforded the opportunity to thoroughly review the calculations.²³ I agree with SESA's position. LUMA's proposal as filed is incomplete. It should be supplemented by a compliance filing that addresses the key design criteria discussed above prior to implementation as a pilot mechanism and include formulas, inputs, data sources, and workpapers. This should be filed within 30 days of the Commission's decision and order in this case. Any comments on the compliance filing should be filed within 20 days of the date of the compliance filing.

To ensure that the mechanism is functioning as intended and promotes customer trust, I also recommend that LUMA file the decoupling mechanism calculations and associated workpapers annually at the time of its request for an adjustment to the decoupling rider. PREB should then afford time for stakeholders to review the filings, submit discovery requests, and submit comments. PREB should consider any concerns raised during this process when approving, approving with modification, or rejecting any adjustments to the decoupling rider.

In addition, at the time of the next rate case, I recommend that the pilot decoupling mechanism be thoroughly reviewed. In particular, I recommend that LUMA submit testimony regarding its view of how the mechanism has functioned and any proposed modifications for PREB's consideration.

²² Response to PC-of-LUMA-DECOUP-14.

²³ Datta Direct Testimony pp. 36-38.

III. RECOMMENDATIONS

LUMA's proposed revenue decoupling mechanism would provide revenue certainty and ensure that LUMA and Genera, operators of PREPA, have adequate funding for operating and investing in the power system, regardless of changes in electricity sales. However, LUMA's filing lacks critical details. To address this gap and ensure that the decoupling mechanism is implemented in a manner that is in the public interest, I recommend that PREB:

- Base the decoupling revenue target on the utility's revenue requirement across all customer classes. A single systemwide target will reduce rate volatility, avoid disproportionate impacts on small classes, and simplify administration.
- Exclude variable costs, such as fuel and purchased power, from the decoupling formula because separate riders already reconcile those costs.
- Implement *full decoupling* without weather normalization to improve transparency and reduce complexity.
- Require annual decoupling adjustments. An annual reconciliation strikes a reasonable balance between reducing bill volatility and limiting administrative burden while still providing timely revenue recovery.
- Require that the mechanism operate in both directions, with surcharges when revenues fall short of the authorized amount and refunds when revenues exceed it. A bidirectional approach ensures that customers and the utility share both upward and downward revenue deviations.
- Establish a soft cap on upward adjustments equal to 3 percent of annual revenues subject to the decoupling mechanism, while placing no cap on downward adjustments (refunds). The utility should defer any unrecovered amounts above the cap and recover them in future decoupling adjustments or address them in the next rate case. A cap protects customers from sudden bill increases while signaling the need for additional regulatory review if persistent under-recoveries occur.
- Require implementation of the decoupling mechanism through a rider rather than through deferral accounting. A rider allows timely, transparent reconciliation of revenues, supports stable utility cash flow, and avoids large accumulated balances that could lead to significant future rate increases.
- Include sales lost due to outages in the decoupling calculation. Excluding these sales would reduce revenues available for system maintenance and investment. PREB should

address reliability and performance accountability through separate incentive mechanisms rather than by excluding outage-related sales.

- Require LUMA to file a complete description of the decoupling mechanism before implementation, including formulas, inputs, data sources, and workpapers. This should be filed within 30 days of the Commission's decision and order in this case. Any comments on compliance filings shall be filed within 20 days of the date of the compliance filing.
- PREB should also require LUMA to submit updated calculations and workpapers annually when requesting adjustments to the rider and provide stakeholders with an opportunity to review these filings, conduct discovery, and submit comments before PREB approves adjustments.
- Conduct a thorough review of the pilot decoupling mechanism during the next base rate case. This review should include testimony from LUMA on the mechanism's performance and any proposed modifications based on experience to date.

Taken together, these recommendations would create a revenue decoupling mechanism that delivers stable cost recovery, promotes affordability and fairness for customers, and enhances regulatory transparency.

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-2

SUBJECT

Permanent Rates – Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Please explain in detail how the revenue decoupling mechanism would work in terms of frequency of adjustments. Would there be monthly adjustments or annual accrual of over- and under-recoveries for collection/refund over the subsequent 12 months?

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response

LUMA notes that the Energy Bureau's February 27th Resolution and Order Adding Two Filing Requirements stated that "[t]he proposed mechanism should provide for reconciliation at *least semiannually*." That said, the simplest approach would be an annual adjustment because it would incorporate seasonal variations and be administratively easier to implement. The more frequent the adjustment(s), the more complicated and costly it will be to the design and build the rider for collection/refund(s).

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-3

SUBJECT

Permanent Rates – Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Please explain in detail how the revenue decoupling mechanism would work in terms of how target revenues for each month or year would be determined. In your response, please describe whether these targets would exclude any cost categories (e.g., fuel costs or other variable costs) and whether the revenue targets would be adjusted for the number of customers.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response

There are several reasonable ways to set target revenues for a decoupling mechanism: revenue per customer, revenue per class, total utility revenue, and others. In general, there would be no cost category exclusions because revenue decoupling is a function of utility revenue compared to the target authorized revenue (on a per customer, total utility or other basis) rather than a comparison of underlying costs or expenses. LUMA notes fuel and purchased power would not need to be included because the FCA and PPCA rider formulas already contain their own reconciliation mechanisms.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-4

SUBJECT

Permanent Rates –Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Please explain in detail how the revenue decoupling mechanism would work in terms of undercollection due to reduced sales resulting from power outages. Would decoupling apply in this case?

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response

Yes. LUMA has provided evidence in this rate review that demonstrates that continued deferral or postponement of maintenance and capital improvement(s) driven by rates that are insufficient to cover the operation and maintenance needs of the energy system has deprived the utility of resources needed to keep up with the degradation of the transmission and distribution (“T&D”) system. The severely deteriorated state of the grid when LUMA took over as the T&D Operator is also well-documented (please refer SESA-of-LUMA-RATE_DES-4). Based on this, the utility is at a high risk of suffering unplanned outages. In order to support the financing of the utility (as PREPA remains cash-financed) to remediate these challenges and invest in the system to prevent future outages, LUMA recommends that reduced sales from power outages should be contemplated by the revenue decoupling mechanism. To the extent the system is sufficiently hardened and resilient, then undercollection due to reduced sales from power outages can be reconsidered at a later date.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-5

SUBJECT

Permanent Rates – Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Please explain in detail how the revenue decoupling mechanism would work in terms of collecting or refunding any under- or over-collection. Would there be a decoupling rider on customers' bills?

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response

Decoupling could be achieved via a separate rider that is established and regularly updated by the PREB. The decoupling mechanism could also use deferral accounting to recover (or credit) funds against the authorized revenue requirement(s) in the next rate case. Funding to support the design and implementation of such mechanism within LUMA's billing system is currently not contemplated in LUMA's rate review proposal.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-7

SUBJECT

Permanent Rates – Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon, page 30, lines 705-707. Is LUMA proposing a bidirectional decoupling mechanism? Please explain.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

LUMA's proposal did not specify whether the decoupling mechanism would be bidirectional (i.e., some decoupling mechanisms are bidirectional, and they may function in different ways). The benefits of a bidirectional decoupling mechanism where funds are returned is that customers are prevented from "overpaying" if total revenue collected exceeds authorized. However, a drawback of that approach may be that an increase in revenues would not be reinvested in the electric system in Puerto Rico.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-9

SUBJECT

Permanent Rates – Rate Design

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Please explain which classes the decoupling mechanism would apply to.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

LUMA did not make a particular proposal about which classes the decoupling mechanism would – or would not – apply to. The benefit of exempting customer classes from the revenue decoupling mechanism is avoidance of inter-class cross-subsidization. For example, large commercial and industrial customers often elect to opt out because their usage is less impacted by the policy drivers of the decoupling mechanism. A drawback could be that there is a greater impact on the customers to which the decoupling mechanism does apply if there are fewer billing determinants to spread the true-up.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-10

SUBJECT

Permanent Rates – Decoupling

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Would revenue targets and decoupling adjustments be applied to individual classes separately, or to combined sales of all classes? Please explain.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

LUMA's proposal does not discuss the revenue decoupling adjustments applying to customer classes separately or to the combined sales of all classes. The benefits of applying a decoupling mechanism to individual classes separately would be that adjustments could be based on each individual customer class's revenue in the prior year compared to the authorized forecast, which provides the most accurate mechanism for each customer class that is subject to decoupling.

However, the drawbacks to applying to individual classes separately is having a smaller group of customers over which to spread any adjustments. In other words, if the adjustment is applied on a class-by-class basis, then the burden of the adjustment is shared across a smaller group of customers. Whereas, in a total utility approach, the impact is spread across a larger group of customers thereby minimizing the impact on any individual class. Separation by class also creates greater administrative burden versus a total utility approach that would be simpler to administer and potentially less confusing to customers.

Based on this, the total utility approach would effectively socialize all revenues into a single adjustment that would be applied to all customer classes subject to decoupling.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-13

SUBJECT

Revenue Decoupling

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. Would revenue decoupling provide any financial benefits in terms of allowing the Utility to access financing on more favorable terms? Please explain.

RESPONDER

Andrew Smith

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Depending on how it is designed, a revenue decoupling mechanism will reduce the volatility of utility revenues, which is generally viewed favorably by credit rating agencies. Reduced revenue volatility can also improve the financial health of the utility. However, it is not possible to determine the extent to which a decoupling mechanism would have any impact on PREPA's ability to access capital markets on favorable terms given the conditions under which PREPA would exit Title III bankruptcy are not known or defined at this point in time.

Attestation

I, Andrew Smith, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Andrew Smith

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-DECOUP-14

SUBJECT

Permanent Rates – Decoupling

REQUEST

Refer to LUMA Exhibit 20.00, Direct Testimony of Sam Shannon. If revenue decoupling were approved, how would this impact the need for the Utility to increase fixed charges to ensure adequate collection of revenues?

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

As described in LUMA Ex. 20.0, Sam Shannon's expert testimony, the proposed fixed charges to residential and small commercial customers is based on the functionalized cost analysis as part of the cost-of-service study.¹ The fixed charges being proposed by LUMA would not change as a result of decoupling because those charges are meant to reflect the customer-classified costs.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

¹ See LUMA Ex. 20.0 Sam Shannon's Expert Testimony, Q/A 57

Melissa Whited, Vice President, Consulting

Synapse Energy Economics | 485 Massachusetts Avenue, Suite 3 | Cambridge, MA 02139 | 617-453-7024
mwhited@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Vice President*, April 2023 – Present; *Senior Principal*, May 2022 – April 2023, *Principal Associate*, 2017 – May 2022, *Senior Associate*, 2015 – 2017, *Associate*, 2012 – 2015

Consult and provide analysis of rate design proposals, alternative regulation, and other topics including distributed energy resources and electric vehicles. Develop expert witness testimony in public utility commission proceedings. Author reports on topics at the intersection of utility regulation, customer protection, and environmental impacts.

University of Wisconsin - Madison, Department of Agricultural and Applied Economics, Madison, WI. *Teaching Assistant – Environmental Economics*, 2011 – 2012

Developed teaching materials and led discussions on cost-benefit analysis, carbon taxes and cap-and-trade programs, management of renewable and non-renewable resources, and other topics.

Public Service Commission of Wisconsin, Water Division, Madison, WI. *Program and Policy Analyst - Intern*, Summer 2009

Researched water conservation programs nationwide to develop a proposal for Wisconsin's state conservation program. Developed spreadsheet model to calculate avoided costs of water conservation in terms of energy savings and avoided emissions.

Synapse Energy Economics, Cambridge, MA. *Communications Manager*, 2005 – 2008

Developed technical proposals for state and federal agencies, environmental and public interest groups, and businesses. Edited reports on energy efficiency, integrated resource planning, greenhouse gas regulations, renewable resources, and other topics.

EDUCATION

University of Wisconsin, Madison, WI

Master of Arts in Agricultural and Applied Economics, 2012

Certificate in Energy Analysis and Policy

National Science Foundation Fellow

University of Wisconsin, Madison, WI

Master of Science in Environment and Resources, 2010

Certificate in Humans and the Global Environment

Nelson Distinguished Fellowship

Southwestern University, Georgetown, TX

Bachelor of Arts in International Studies, *Magna cum laude*, 2003.

ADDITIONAL SKILLS

- Econometric Modeling – Linear and nonlinear modeling including time-series, panel data, logit, probit, and discrete choice regression analysis
- Nonmarket Valuation Methods for Environmental Goods – Hedonic valuation, travel cost method, and contingent valuation
- Cost-Benefit Analysis
- Input-Output Modeling for Regional Economic Analysis

FELLOWSHIPS AND AWARDS

- Winner, M. Jarvin Emerson Student Paper Competition, Journal of Regional Analysis and Policy, 2010
- Fellowship, National Science Foundation Integrative Graduate Education and Research Traineeship (IGERT), University of Wisconsin – Madison, 2009
- Nelson Distinguished Fellowship, University of Wisconsin – Madison, 2008

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TESTIMONY AND COMMENTS

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Resume updated March 2025

**GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU**

	)	CASE NO: NEPR-AP-2023-0003
IN RE: PUERTO RICO ELECTRIC	)	
POWER AUTHORITY RATE REVIEW	)	SUBJECT: BILLING DETERMINANTS,
	)	COST ALLOCATION AND REVENUE
		ALLOCATION, RATE DESIGN

EXPERT REPORT

OF

Zachary Ming

PC Exhibit 61.0

Energy and Environmental Economics, Inc. (“E3”)

October 6, 2025

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Executive Summary

This report evaluates three components of LUMA Energy's July 3, 2025, application and intervenor responses: billing determinants, cost and revenue allocation, and rate design. This report was prepared by Zachary Ming, Partner at Energy and Environmental Economics, Inc. (E3) for the Puerto Rico Energy Bureau ("Energy Bureau" or "PREB").

These are the key findings from each section of this report.

Billing Determinants

LUMA's decision to use a regression-based methodology for forecasting billing determinants is conceptually sound, but its implementation is flawed. The flaws that I identified are inconsistent weather assumptions, failure to account for historical impact of load modifiers, and omission of electricity price as an explanatory variable. In addition, the demand (kW) billing determinant forecast that LUMA used for its cost-of-service study (COSS) and rate design is not aligned with the load forecast. I recommend that the Energy Bureau adopt LUMA's fiscal year (FY) 2026 forecast but direct LUMA to correct the above deficiencies in future filings. LUMA should update its billing determinant forecast in advance of FY2027 and FY2028 as more data becomes available.

Cost Allocation and Revenue Allocation

LUMA performed a cost-of-service study (COSS) to functionalize, classify, and allocate its costs to customer classes. There were several places where LUMA's methodology was not reasonable, represented one extreme in the range of possible methods, or lacked justification for assumptions. When I tested the sensitivity of the class cost allocation to these methodological choices, however, the class cost allocation changed by less than 2% for most rate classes. I therefore recommend the Energy Bureau adopt LUMA's COSS methodology.

LUMA's proposed revenue allocation to each rate class differs from cost allocation to each rate class from its COSS. LUMA proposed gradually adjusting revenue allocation from current levels, consistent with the rate design principle of stability. LUMA's final year of proposed revenue allocation (FY2028) deviates from its calculated cost allocation, without sufficient justification. I recommend that the Energy Bureau identify any rate classes that, in FY2028 rates, should receive enduring subsidies in their revenue allocation relative to their cost of service, and an appropriate level for the subsidies (i.e., an Energy Bureau-specified percentage reduction relative to class cost allocation calculated in the COSS).

LUMA also proposed a new methodology for discounting the cost of electricity for low-income customers that no longer specifies an explicit discount. I recommend that the Energy Bureau direct LUMA to continue the current practice of calculating discounts for low-income rate classes and recovering the corresponding revenues through a rider.

Rate Design

LUMA proposed to increase the fixed customer charge for the general residential rate class (GRS) from \$4/month to \$20/month by FY2028. LUMA's proposed GRS customer charge reasonably balances principles of cost-causation and bill stability. I recommend that the Energy Bureau adopt this increase. LUMA also proposed to increase the fixed customer charge for small commercial rate class (GSS) from \$5/month to \$75/month by FY2028. Although LUMA's proposed

customer charge is consistent with cost-causation, it results in a bill increase for small usage customers that is inconsistent with the principle of bill stability. I recommend that the Energy Bureau increase the GSS customer charge to \$25/month by FY2028.

LUMA proposed maintaining existing rate designs for most other customer classes. I recommend several changes including collapsing tiered energy rates to better align with the rate design principles of simplicity and economic efficiency.

Overview and Introduction

This report evaluates three core elements of LUMA's July 3, 2025 application and intervenor responses:

1. **Billing determinants.** LUMA's proposed load forecast and billing determinants. LUMA uses these determinants to allocate costs and calculate rates.
2. **Cost and revenue allocation.** LUMA's proposed cost-of-service study (COSS) and how much revenue LUMA proposes to recover from each rate class.
3. **Rate design:** the specific charges by which LUMA proposes to recover costs from customers.

My name is Zachary Ming. I am a Partner with Energy and Environmental Economics, Inc. ("E3"), an energy consulting firm based in San Francisco, California. I have been employed by E3 for over 12 years and have worked on topics related to rate design and cost allocation for utilities across North America throughout this time. I have testified before utility commissions in South Carolina and New Brunswick on the topic of retail rate design and cost allocation. I have also testified to the U.S. Federal Energy Regulatory Commission on the topic of transmission rate design. I have worked with utilities such as Nova Scotia Power to develop new rate designs that properly assign costs to new large loads. In addition to full-time work at E3, I am an Adjunct Lecturer at Stanford University where I teach the course *Electricity Economics*. Rate design is one of the topics I cover in the course.

Billing determinants

A. Issue background

Billing determinants measure how utility customers use electricity and cause costs. The three main billing determinants are number of customers, energy consumption, and demand.

Number of customers refers to the number of electricity customer accounts in a class.

Energy consumption, measured in kilowatt-hours (**kWh**), refers to the total quantity of electricity consumed by a customer class over a time period (e.g., year or month). Utilities often divide energy consumption into subcategories such as:

- **Time-of-use periods:** energy consumption within specified time periods, such as individual hours, or multi-hour periods such as "peak" and "off-peak;" and
- **Tiers:** energy sales divided into usage levels, such as the quantity of energy consumed per customer below and above 425 kWh per month.

Demand, measured in kilowatts (kW), refers to the instantaneous consumption of electricity. Whereas energy consumption shows how much electricity customers use over time, demand signals the capacity needed in a single moment. Utilities can measure demand for individual customers or groups of customers. Utilities use multiple metrics for measuring demand, including:

- **Non-coincident peak (NCP) demand:** the maximum electricity demand of a customer or class of customers during a period of time (e.g., month or year); and
- **Coincident peak (CP) demand:** the demand of a customer or class of customers during the entire utility system's peak.

Utilities use billing determinants to allocate costs between customer classes, and then design rates for the purpose of billing customers for their usage. Not every billing determinant is used for each of those tasks. For example, the utility will not have a way to measure and bill for kW demand, or for energy use at specific time intervals without advanced metering infrastructure (AMI). A utility can, however, estimate these values for customer-class cost allocation by sampling individual customers within a class, then using statistical methods to extrapolate to the full customer class. This process is called load research.

Utilities use billing determinants for three functions:

- **Cost Allocation:** Utilities allocate costs to customer classes based on each class's share of the total system billing determinants. Suppose that a utility determines that peak demand drives \$100 million of its total revenue requirement. Now assume that a particular customer class's billing determinants demonstrate that it is responsible for 30% of the utility's peak demand. The utility would allocate \$30 million of the total revenue requirement to that customer class. The utility repeats this exercise for not just demand-driven costs but also energy-driven and customer-driven costs.
- **Rate Design:** Once each customer class has received its allocated share of total costs, the utility uses billing determinants to calculate rates. For example, for a customer class with \$50 million of allocated annual energy costs and 250,000,000 kWh in annual energy sales, the utility calculates a rate of \$0.20/kWh by dividing allocated costs by energy sales. The utility may consider different rate design components, such as fixed charges and demand charges, depending on its cost allocation and billing determinants.
- **Customer Billing:** Once the utility calculates rates, it can calculate each customer's monthly bill based on metered usage.

Billing determinants used for the purposes of cost allocation and rate design are forward-looking estimates, while billing determinants used for customer billing are backward-looking actuals. The inevitable differences between these two measures mean that over a full year the utility will recover from customers more or less than its authorized revenue requirement. Minimizing this difference requires the utility and the regulator to make the forward-looking billing determinant estimates as accurate as possible. One way to correct for these differences is to use a true-up mechanism such as "revenue decoupling."

B. Position of the applicant

In this section, I summarize the position of the applicant on topics related to load and billing determinant forecasts. I evaluated the position of the applicant separately in Section D.

In its July 3, 2025, application, LUMA proposed load and billing determinant forecasts. Ms. Joseline N. Estrada-Rivera, Director of Tariff & Budgets, Load Forecasting and Research for LUMA,

presented direct testimony on behalf of LUMA to support the load forecast. (LUMA Ex. 4.0, Summary) Ms. Estrada sponsored LUMA Exhibits 4.01 through 4.04 that contained the load forecasting models, load modifier forecast, and a customer forecast.¹

LUMA used the resulting load forecast, after including impacts of load modifiers, as its approved fiscal plan forecast. LUMA used the consumption forecast to determine base revenues, the generation forecast to support fuel and purchased power costs, and the peak forecast for capacity planning.

Ms. Estrada converted the load forecast for the customer classes (e.g., residential, commercial, industrial) to a billing determinant forecast for each rate class (e.g., GRS, LRS, GSS) based on 2024 historical data, as discussed below.² LUMA used the billing determinant forecast for its proposed cost-of-service study (COSS), revenue allocation, and rate design.³

B.1. Load forecasting methodology

LUMA developed load forecasts for three components:⁴

- **Consumption:** “the amount of energy used by the customers measured behind the meter in kWh;”
- **Generation:** “the energy delivered to the electrical grid, from where it is transmitted and distributed to customers.” Generation is higher than consumption due to line losses;
- **Peak demand:** “the highest level of energy demand on a grid within a specific time frame, typically measured over one hour, [and] is measured in MW.”

LUMA used the following process to produce the final consumption, generation, and peak demand forecasts:

1. LUMA forecasted the base consumption (described below) for each customer class.
2. LUMA forecasted key load modifiers (described below) for each customer class.
3. LUMA applied the forecasts of load modifiers to the base consumption forecast to produce the final consumption forecast for each rate class.
4. LUMA derived the annual generation forecast by applying the average FY22 - FY24 efficiency to the final consumption forecast.⁵
5. LUMA derived the annual peak demand forecast by applying historical class load factors to the final consumption forecast.

¹ LUMA Ex. 4.0, p.2, II.42-45.

² PC-of-LUMA-RATE-DES-12, part a.

³ LUMA’s proposed COSS, revenue allocation, and rate design are outlined in the testimony of Mr. Sam Shannon, LUMA Ex. 20.0 and summarized by the PREB’s consultants in two separate reports.

⁴ LUMA Ex. 4.0 p.15, II.-295-299.

⁵ Average efficiency is calculated as total consumption divided by total generation for FY2022–FY2024. See LUMA Ex. 4.02, “Base Load Forecast” tab.

6. LUMA applied monthly adjustment factors to shape annual values for consumption, generation, and peak demand into monthly values.

The base consumption forecast projects electricity use for each class, based on historical uses of electricity, socioeconomic variables, and temperature. The base consumption forecast represents expected consumption before accounting for load modifiers (described below). Ms. Estrada refers to the base consumption forecast as “base load.”

When developing the base consumption forecast, LUMA forecasted the three largest customer classes – residential, commercial, and industrial – using regression models. For smaller customer classes (public lighting, agriculture, and other authorities), LUMA held the base consumption forecast flat with the current-year estimate, making adjustments only in leap years.⁶

Load modifiers are technologies that alter customers’ electricity consumption that LUMA forecasts separately because of unique adoption trends or load profiles. Ms. Estrada described load modifiers as “variables that have impacted previous load forecasts.”⁷ LUMA adjusted base consumption forecasts with four load modifiers:⁸

- **Electric vehicles (EV):** increase in base consumption
- **Energy efficiency (EE):** reduction in base consumption
- **Distributed Generation (DG)/ Net Metering (NM) Photovoltaic (PV):** reduction in base consumption
- **Combined Heat and Power (CHP):** reduction in base consumption

B.1.a. Base consumption forecasts

LUMA and its consultant, Guidehouse, developed the base consumption forecasts for each major customer class using regression models.¹⁰ Ms. Estrada described regression in simple terms: “Regression models are statistical techniques used to examine the relationship between an endogenous (or dependent) variable and one or more exogenous (or independent) variables.”⁹

LUMA leveraged the following key input data in its models:¹⁰

- Monthly billing data by class (historical, since 2010) to select exogenous variables for the regression model for each customer class
- Gross National Product (“GNP”) (historical and projected), provided by the Fiscal Oversight and Management Board (“FOMB”)
- Population (historical and projected), provided by FOMB
- Cooling Degree Days (“CDD”), derived by Guidehouse from observed data. Analysts use CDD as a metric to estimate cooling energy demand based on daily temperature variations.¹¹

⁶ LUMA Ex. 4.0 p.4,5, ll.–87-90.

⁷ LUMA Ex. 4.0 p.6, ll.–115-119.

⁸ LUMA Ex. 4.0 p.6, ll.–115-117.

⁹ LUMA Ex. 4.0, p.6, ll.–121-123.

¹⁰ LUMA Ex. 4.0, p.5, ll.–96-108.

¹¹ Cooling Degree Days (CDD) are equal to the number of degrees Fahrenheit a given day’s mean temperature is above 65 F. CDD is typically reported cumulatively over a month.

LUMA also included seasonal terms in all regression models, so monthly forecasts reflected typical class behavior. LUMA assessed the models and monitored large deviations due to recent factors impacting loads—particularly in the industrial and residential classes.

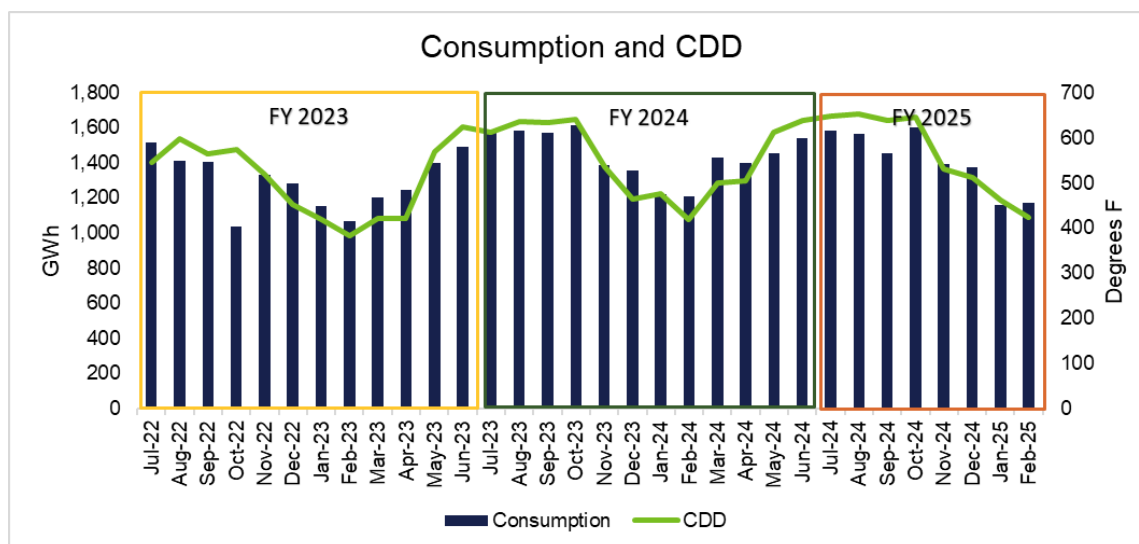
B.1.a.i. Residential regression model

The residential regression model used GNP, population, two additional exogenous variables to reflect post-pandemic changes in load trends, and CDD-intensity adjustments when cumulative CDD exceeded 500°F in a given month. LUMA removed outliers such as earthquakes and hurricanes from estimation as atypical events.¹²

Ms. Estrada identified CDD as a key residential driver: “CDD is the secondary component influencing residential load, especially due to the warmer temperatures that commenced in May 2023.”¹³ LUMA leveraged CDD forecast scenarios based on different percentiles of increase, using the median of the observed monthly CDD. The residential model uses the 73rd percentile of the historical monthly CDD data through 2028. Ms. Estrada selected the 73rd percentile scenario to account for the recent rise in temperatures that are expected to persist.¹⁴

Figure 1 depicts LUMA’s view of the relationship between consumption and CDD. Ms. Estrada reported a 9.6% (583°F) historical CDD increase in FY2024 compared to FY2023. She reported an 11.7% increase in consumption for the same period. Through February of FY2025, CDD rose by 2.1% or 94°F year-over-year while consumption fell 2% due to the December 31, 2024 outage and load shedding resulting from constrained generator capacity.¹³

Figure 1: Consumption and CDD¹³



¹² LUMA Ex. 4.0, p.7, ll.145–150.

¹³ LUMA Ex. 4.0, p.25, ll.480–491.

¹⁴ LUMA Ex. 4.0, p.9, ll.180-182.

B.1.a.ii. Commercial regression model

The commercial regression model used GNP, CDD, a COVID adjustment, and monthly CDD adjustments as exogenous variables. LUMA used the 50th-percentile (median) monthly CDD scenario for the commercial model.¹⁵

B.1.a.iii. Industrial regression model

The industrial regression model used GNP as the exogenous variable. Ms. Estrada noted that CHP has a significant impact on industrial consumption. LUMA, therefore, back-cast industrial load to account for customers generating their own energy through CHP. Estimated industrial demand excluding CHP displacement formed the basis for the industrial forecast.¹⁶

B.1.a.iv. Smaller classes model

LUMA did not use a regression model for the smaller customer classes of public lighting, agriculture, and other authorities. LUMA held smaller-class forecasts at current-year levels, adjusting only for leap years.¹⁷

B.1.b. Load modifiers

After developing the annual base consumption forecasts, LUMA forecasted the impacts of several load modifiers, then applied these forecasts to the base consumption forecast for each customer class. As explained by Ms. Estrada, “Load modifiers are variables that have impacted previous load forecasts such as reductions for EE, DG, and CHP, as well as an addition for the expected consumption increase attributed to the adoption of electric vehicles (‘EV’).”¹⁸

B.1.b.i. Distributed Generation (DG) and Net Metering (NM)

Distributed generation (DG) energy produced locally at customer sites. In Puerto Rico, DG is primarily solar photovoltaics (PV). Distributed solar PV produces energy at the customer’s location, reducing the energy that the customer would otherwise consume from the utility. If the customer’s solar PV system produces more energy than what the customer consumes at their location, the system injects the excess energy into the distribution grid for use by other customers. Therefore, the DG load modifier is a reduction to the base consumption forecast.

Net metering (NM) is a program that DG customers can enroll in to receive compensation for any excess energy produced by their DG system that is injected into the distribution system. LUMA used NM enrollment data as a proxy for total customer PV, since LUMA did not have visibility into customers who have PV systems but do not participate in the NM program.

¹⁵ LUMA Ex. 4.0, p.8, ll.175-176.

¹⁶ LUMA Ex. 4.0, p.7,8, ll.-152-158.

¹⁷ LUMA Ex. 4.0,p.5, ll.-110-111.

¹⁸ LUMA Ex. 4.0, p.6, ll.-115-119.

LUMA used a Gompertz Growth Model to project residential and commercial PV capacity (kW) adoption. LUMA held industrial and agricultural PV constant due to observed stagnation.¹⁹ LUMA converted capacity to generation using class-specific monthly capacity factors.

LUMA noted that some customers install battery storage systems alongside distributed PV as part of their NM system. Ms. Estrada explained that LUMA did not include direct assumptions on battery storage in the DG forecast because, she said, the primary objective of the forecast is to project future energy consumption from the utility grid, and LUMA assumed all energy generated by a customer's DG system is used to offset that grid consumption. In addition, Ms. Estrada noted that empirical data indicates that customers are primarily using their batteries for backup reliability, not daily load-shifting.²⁰

LUMA explained that energy reliability concerns drive customer installations of PV systems.²¹ Ms. Estrada noted that PV installations increase after outage events, such as those caused by hurricanes.²²

Ms. Estrada highlighted the increase in residential NM since 2017, as shown in Figure 2. After LUMA assumed T&D operations at PREPA, NM enrollments exceeded 3,000 customers per month. Ms. Estrada reported approximately 700 kWh of displaced load per NM customer per month in FY2021–FY2025.²³ Ms. Estrada noted lower export rates in FY2024 and FY2025 than in prior years, indicating increased self-consumption during hotter periods.²⁴

¹⁹ The Gompertz Curve is an S-shaped growth model often used in biology, demography, and technology adoption. It is defined as $N(t) = K * \exp(-B * \exp(-C * t))$, $N(t)$ is the size of the population at time t , where K is the carrying capacity, and B and C shape the growth rate and inflection point. See <https://statisticseasily.com/glossario/what-is-gompertz-curve-understanding-growth-models/>.

²⁰ PC-of-LUMA-LOAD_FOR-7, part e – f.

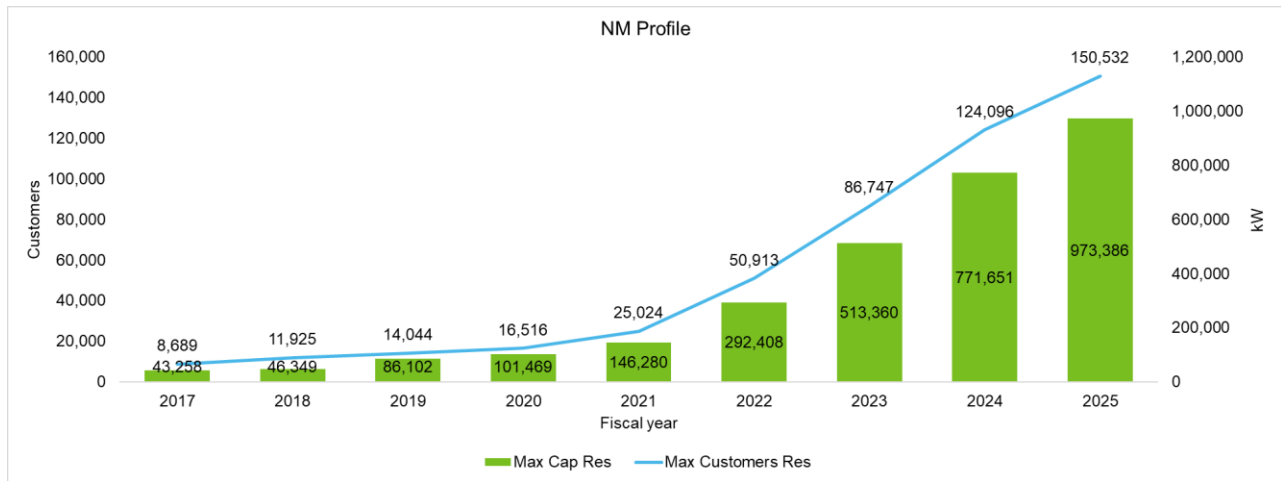
²¹ PC-of-LUMA-LOAD_FOR-7, part b.

²² LUMA Ex. 4.0 p.24,25, ll.-442-445.

²³ LUMA Ex. 4.0 p.24,25, ll.-460-465.

²⁴ LUMA Ex. 4.0 p.25, ll.-475-478.

Figure 2: Growth of Net Metering (NM) customers and capacity from 2017 through 2025²⁵



B.1.b.ii. Combined Heat and Power Systems (CHP)

Combined heat and power (CHP) generates electricity and useful heat from a single fuel in one process, improving efficiency and lowering energy costs for large sites like industrial plants, hospitals, and universities.

Ms. Estrada noted that consumption in the industrial sector has declined, with CHP being the most significant factor contributing to this decline. Other factors include impacts from customer energy efficiency programs and industry operations closures in Puerto Rico.²⁶

LUMA used data from customers' CHP system evaluations to project CHP capacity in the commercial and industrial customer classes in FY2026 through 2028. LUMA calculated an average capacity factor for future CHP customers based on historical CHP customer data from before and after installation. LUMA assumed an increase in CHP production for each customer in year two of operation.²⁷

B.1.b.iii. Energy Efficiency

Energy Efficiency (EE) measures help customers reduce electricity use while performing the same tasks. Ms. Estrada stated that LUMA calculated EE reductions were based on meeting the goal of "30% reduction of electricity by 2040" relative to FY2019 net utility sales, as stated in Act 17-2019 and the Energy Bureau's Jan. 21, 2022 EE Regulation (NEPR-MI-2021-0005).²⁸ LUMA calculated the required annual load reduction under the regulation, then distributed it across each

²⁵ LUMA Ex. 4.0 p.28, ll.-525.

²⁶ LUMA Ex. 4.0 p.24, ll.-453-455.

²⁷ LUMA Ex. 4.0 p.11,12, ll.-231-246.

²⁸ LUMA Ex. 4.0 p.12, ll.-248-251 and 2023 Certified Fiscal Plan for the Puerto Rico Electric Power Authority, p.76. <https://ntc-prod-public-pdfs.s3.us-east-2.amazonaws.com/eVtTyFLQ2DBtKVd4UmJN9FcjOvw.pdf>.

rate class using dispatch modeling in Aurora. LUMA used the resulting consumption reduction as the energy efficiency load modifier in each year.²⁹

B.1.b.iv. EV charging load

EV charging load refers to the electricity used to charge electric vehicles. LUMA used the Puerto Rico (PR) 100 light duty vehicles (LDV)/ medium duty vehicles (MHDV) charging data as the basis for the EV charging load modifier.³⁰ Ms. Estrada adjusted the LDV efficiency (kWh/vehicle) upward as PR100's assumption was "lower than what could be expected with modern vehicles." LUMA left the efficiency of MHDVs unchanged and adopted the revised load as the EV load modifier.³¹

B.1.b.v. Summary of load modifiers

Table 1 summarizes LUMA's view of the directional effect and forecasted consumption effect for FY2026 – FY2028.

Table 1: Effect of load modifiers³²

Load Modifier	Directional Impact on Consumption	Forecasted Consumption (GWh)		
		FY2026	FY2027	FY2028
DG / Net Metering (PV)	Decrease	-1,908	-2,294	-2,647
CHP	Decrease	-865	-1,007	-1,090
EE	Decrease	-80	-129	-192
EV Charging	Increase	52	90	120
Total Base Consumption before Load Modifiers		17,327	17,370	17,511
Resulting Consumption Forecast After Load Modifiers		16,022	15,526	15,198

B.1.c. Generation and peak demand forecast

After producing the base consumption forecast and the adjusted consumption forecast with the load modifiers, LUMA then produced the total annual generation forecast by dividing total

²⁹ LUMA Ex. 4.03, "EE" tab.

³⁰ PR100 is a study performed by local and federal government entities to determine a way to comply with the integration rule by 2050 as established by Act 17-2019. (LUMA Ex. 4.0,p.11.263-264).

³¹ LUMA Ex. 4.0 p.12, ll.-253-261.

³² LUMA Ex. 4.03, "Summary Modifiers" and "DG and CHP Applied" tabs.

annual consumption (sum of all customer classes) by the average efficiency observed in FY2022 through FY2024.³³

LUMA calculated the annual peak demand forecast by applying historical load factors to the consumption of each customer class. The peak demand forecast does not consider the load shape of any of the load modifiers.³⁴

B.1.d. Monthly distribution and seasonal adjusters

LUMA converted the annual forecasted consumption, generation, and peak to monthly values based on seasonal trends in each month. LUMA used seasonal adjustment programs from the United States Census and historical data through June 2024.³⁵

B.2. Load forecast results

Ms. Estrada described two competing forces on the final load forecast: “historically higher temperatures in Puerto Rico [were] having an upward impact on consumption” and “[t]he substantial integration of self-generation systems [was] having a significant downward impact on consumption.” Overall, Ms. Estrada concluded that “base demand will decrease over the three years of projection.”³⁶

LUMA’s forecast for FY2026 indicated a 5.0% decrease in total demand compared to the estimate for FY2025.³⁷ Ms. Estrada attributed the drop to a potential increase in self-generation systems caused by recent system reliability issues.³⁸

In later years, LUMA projected further declines: FY2027 decreased 7.9% relative to FY2026, followed by a decrease of 9.9% in FY2028 compared to FY2027. Ms. Estrada expected residential, commercial, and industrial consumption to decline each year.³⁹

Table 2 shows the final fiscal plan forecast for consumption, generation, and peak demand.

³³ Average efficiency is calculated as total consumption divided by total generation for FY2022–FY2024. See LUMA Ex. 4.02, “Base Load Forecast” tab.

³⁴ PC-of-LUMA-LOAD_FOR-11.

³⁵ LUMA Ex. 4.0, p.16, ll.–317-319.

³⁶ LUMA Ex. 4.0 p.20, ll.–384-390.

³⁷ LUMA Ex. 4.0 p.20, ll.–392-393.

³⁸ LUMA Ex. 4.0 p.20, ll.–395-396.

³⁹ LUMA Ex. 4.0 p.20, ll.–398-401.

Table 2: Fiscal plan forecasts of consumption, generation, and peak demand⁴⁰

Fiscal Year	Consumption (GWh)							Generation	Peak Demand
	Residential	Commercial	Industrial	PL	Agric.	Others Auth	Total		
2022	6,875	7,210	1,869	269	25	34	16,282	19,513	2,960
2023	6,316	7,205	1,680	284	22	38	15,545	18,182	3,049
2024	7,321	8,023	1,772	303	24	39	17,482	19,359	3,181
2025	7,093	7,887	1,511	294	23	38	16,846	18,985	3,184
2026	6,581	7,634	1,459	286	23	38	16,022	18,057	3,028
2027	6,200	7,629	1,367	269	23	38	15,526	17,498	2,932
2028	5,870	7,660	1,331	276	23	38	15,198	17,128	2,862

LUMA reported that the load forecasts for FY2026, FY2027, and FY2028 were 7.2%, 10.1% and 12.0%, respectively, below the 2017 Rate Order Forecast LUMA used to determine current rates.⁴¹ Table 3 shows the comparison between LUMA's current forecast and the 2017 Rate Order Forecast.

Table 3: Load forecast for FY2026, FY2027 and FY2028

Customer Class	FY 2017 *	FY 2026	FY 2027	FY 2028	Variance FY 2026/FY 2017	Variance FY 2027/FY 2017	Variance FY 2028/FY 2017
Residential	6,242.8	6,581.3	6,199.6	5,869.5	5.4%	-0.7%	-6.0%
Commercial	8,322.2	7,634.4	7,629.2	7,660.4	-8.3%	-8.3%	-8.0%
Industrial	2,333.1	1,459.2	1,367.3	1,330.8	-37.5%	-41.4%	-43.0%
Public Lighting	308.7	286.0	268.6	275.8	-7.3%	-13.0%	-10.7%
Agriculture	26.1	23.1	23.1	23.2	-11.5%	-11.5%	-11.3%
Other Authorities	35.4	38.3	38.3	38.4	8.2%	8.2%	8.5%
Total	17,268.3	16,022.3	15,526.2	15,198.0	-7.2%	-10.1%	-12.0%

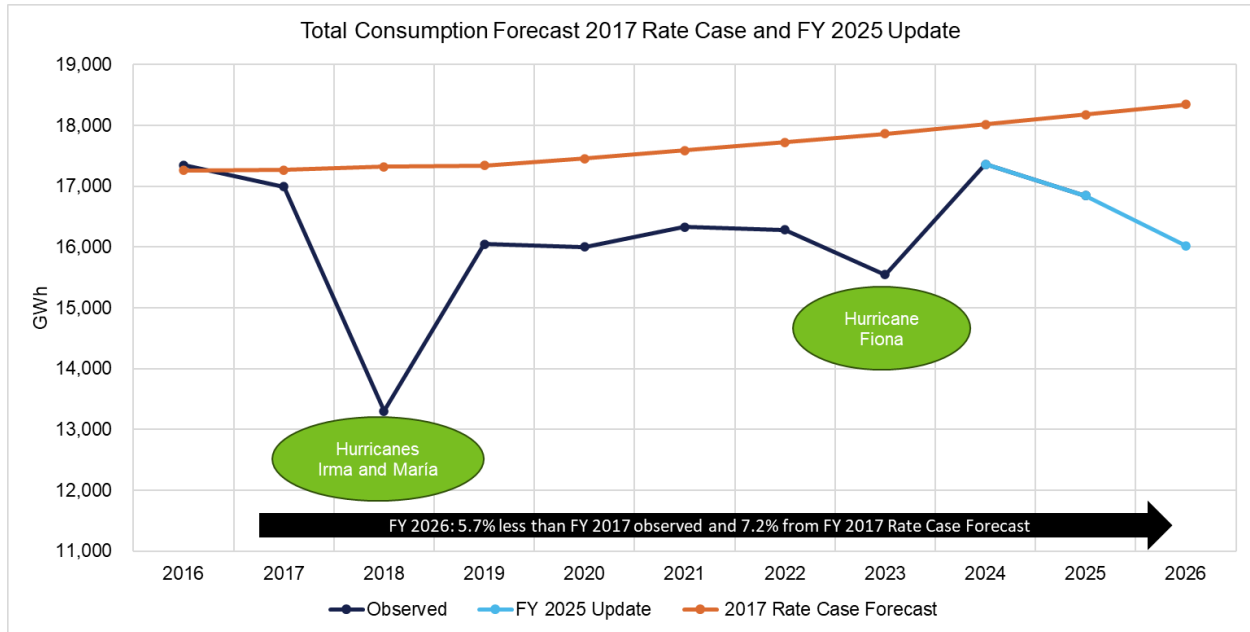
* Forecast Rate Case

Figure 3 shows the comparison of the FY 2025 forecast to historical data and the 2017 Rate Case Forecast. Ms. Estrada identified FY2018 and FY2023 as storm-affected (Irma/Maria; Fiona) and placed the consumption forecast in FY2026 (as part of the FY2025 update) above those levels. She noted the FY2026 consumption forecast is closest to historical levels observed in FY2020, which ran 0.1% higher than the FY2026 projection.

⁴⁰ LUMA Ex. 4.02, "FP approved Load w Modifiers" tab.

⁴¹ LUMA Ex. 4.0 p.21, ll.-405-407.

Figure 3: Total consumption forecast FY2017 and FY2025 update⁴²



B.3. Customer count forecast

LUMA started with historical customer counts by customer class through 2024, then estimated the average customer count for each customer class for 2025 based on year-to-date trends. LUMA used regression models to forecast customer counts for each customer class for 2026 to 2028.⁴³

B.4. Billing determinant forecast

Ms. Estrada converted the energy and customer count forecasts for the customer classes (e.g., residential, commercial, industrial) to a billing determinant forecast for each rate class (e.g., GRS, LRS, GSS) using 2024 historical data.⁴⁴ Table 4 summarizes the rate classes within each customer class. Ms. Estrada calculated energy billing determinants for each rate class by:

- Calculating the ratio of each rate class's energy billing determinant over the total customer class's energy billing determinant in 2024 historical data.
- Applying this ratio to the total customer class load forecast on a monthly basis for FY2026 through FY2028.

Ms. Estrada used the same method for customer counts.

⁴² LUMA Ex. 4.0 p.22, Figure 3.

⁴³ LUMA Ex. 4.04.

⁴⁴ PC-of-LUMA-RATE-DES-12, part a. See Attachment 1 for example calculations.

In contrast, Ms. Estrada based demand billing determinants on “the most recent historic information from the load research sample,” without any relation to LUMA’s load forecast.⁴⁵ In LUMA’s proposed COSS and rate design, demand billing determinants are the exact same for FY2026, FY2027, and FY2028 despite changing load over that same period.

Table 4: Summary of PREPA rate classes.

Customer Class	Rate Class	Rate Class Name
Residential	GRS	General Residential Service
	LRS	Lifeline Residential Service
	RH3	Residential Service for Public Housing
	RFR	Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration
Small Commercial	GSS	General Service at Secondary Distribution Voltage
	USSL	Unmetered Service for Small Loads
	CATV	Cable TV Power Supplies
Medium Commercial & Industrial (C&I)	GSP	General Service at Primary Distribution Voltage
	TOU-P	Time of Use at Primary Distribution Voltage
Large C&I	GST	General Service at Transmission Voltage
	TOU-T	Time of Use at Transmission Voltage
	LIS	Large Industrial Service
	PPBB	Power Producers Connected at PREPA Bus Bar
Public Lighting	PLG	Public Lighting General
	LP-13	Outdoor Sports Field Lighting
Other	GAS	General Agricultural Service and Aqueduct Pumps Operated by Rural Communities

C. Position of the intervenors

In this section, I summarize the position of intervenors on topics related to load and billing determinant forecasts. I evaluated the position of intervenors separately in Section D.

The Institute of Competitiveness and Economic Sustainability (ICSE) submitted the expert witness report of Ramón J. Cao García titled “A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA.” Mr. Cao rejected LUMA’s load forecast. Mr. Cao stated that the load forecasts were “not valid,” given the size of the errors and modeling issues, as he describes in

⁴⁵ PC-of-LUMA-RATE-DES-12.1 and shown in PC-of-LUMA-RATE-DES-12, part a, Attachment 1, “JUL” sheet, columns K through N.

Appendix 1 of his report. He therefore did not use it in ICSE's analysis of the economic effects of LUMA, Genera, and PREPA's proposed revenue requirements.⁴⁶

Mr. Cao referenced Table 4 through Table 7 of Ms. Estrada's testimony, which compared LUMA's forecasts to actuals across several years. Mr. Cao noted that LUMA's forecast errors ranged from -12.2% to 18.7%. He characterizes this magnitude of error as "unacceptable for forecasting," therefore "unsuitable to estimate revenues and expenditures tied to electricity load."⁴⁷

Mr. Cao argued that the regression models for each customer class omitted these key demand drivers:

- Residential class: electricity price and disposable personal income.
- Commercial class: electricity price and net income in the commercial sector.
- Industrial class: electricity price and a measure of US demand for Puerto Rico's manufactured goods.⁴⁸

Mr. Cao stated that all three class models used "a myriad of binary or dummy variables."⁴⁹ He noted that while such variables are common in econometrics, their excessive use can lead to the "dummy variable trap," where multicollinearity violates regression assumptions and causes estimation errors. He warned that Ms. Estrada's testimony did not show tests for independence among regressors.

Mr. Cao noted that the equations did not include intercepts. He also stated that the filing did not provide the estimated coefficients, their standard errors, or standard goodness-of-fit statistics.

Mr. Cao concluded that "[g]iven the inadequate nature of the specification of the load forecast equations, it is not surprising the large load forecasting errors incurred by LUMA."⁵⁰ He did not use LUMA's forecasts in ICSE modelling. Instead, he used the FY2025 historical load. Mr. Cao caveated his use of the FY2025 load, stating that "electricity load shows a downward trend, which results in the use of FY2025 data to somewhat overestimate load, but this expected error is lower than what results from LUMA's load forecasts."⁵¹ LUMA's load forecast and historical loads are shown in this report in Table 2.

⁴⁶ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.2.

⁴⁷ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.18.

⁴⁸ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.20.

⁴⁹ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.20.

⁵⁰ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.21.

⁵¹ Ramón J. Cao García, *A Report on Economic Consequences of July 3, 2025 Filing of LUMA-GENERA-PREPA* p.4.

D.Evaluation of parties' positions

This section presents my evaluation of the applicant and intervenor positions on load and billing determinant forecasts.

D.1. Load forecast methodology

D.1.a. Base consumption forecasts

LUMA's decision to use regression models for the base consumption forecast for each main customer class (residential, commercial, and industrial) is reasonable. Regression models are standard in load forecasting. They capture key drivers of electricity consumption, including weather, season, and economic indicators.

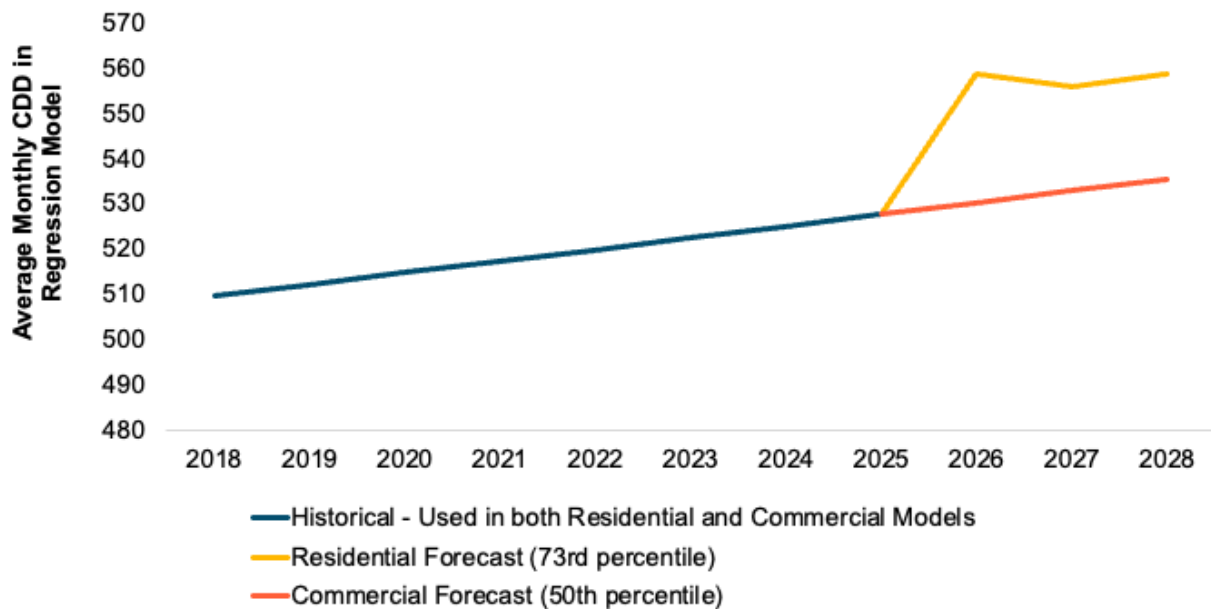
Mr. Cao argued that LUMA used too many binary variables in its regression models. This argument is not persuasive: binary variables are standard for capturing categorical factors without numeric values. LUMA used binary variables in its regression to reflect key impacts such as monthly and seasonal variations and the impact of COVID-19 in certain years.

In the next sections, I evaluate LUMA's regression model for each customer class.

D.1.a.i. Residential regression model

LUMA's decision to use the 73rd percentile of median monthly CDD data for the residential model is inconsistent with the assumption for other customer classes. The commercial model used the 50th percentile for CDD, so LUMA is planning for different weather scenarios for residential and commercial classes. Ms. Estrada noted that residential load is more sensitive to changes in temperature than other sectors, which is why she used the higher percentile for CDD data. Ms. Estrada should account for the higher sensitivity of residential load by using a different coefficient for CDD, not by applying a different weather scenario than the one used in other models.

Figure 4: Average Monthly CDD Used in the Residential Regression Model and the Commercial Regression Model



LUMA failed to adjust the residential regression to account for historical effects of load modifiers, such as DG, EE, and EVs. As a result, the final consumption forecast risks overcounting the effect of load modifiers. LUMA designed its regression model using the historical relationship between consumption and the independent variables. DG, EE, and EV affect historical consumption data that the regression relationship is based on. Therefore, the regression results already implicitly include potential future impacts of these load modifiers.

I expect that EE and EV have relatively small impacts on the regression, given that there is limited EE and EV adoption in Puerto Rico to date. I expect that DG has a larger impact on the regression due to high adoption in the residential sector in recent years. The Energy Bureau should direct LUMA to update its regression model so that it takes into account the historical impact of these load modifiers in future load forecast efforts.

I agree with Mr. Cao's argument that LUMA should include electricity price in the residential regression. Electricity price can impact a customer's consumption, as well as the customer's adoption of DG or EE.

I do not agree with Mr. Cao's argument that disposable personal income should have been included in the regression. LUMA's decision to use GNP as the key economic variable is reasonable for three main reasons:

- Macroeconomic variables such as GNP or Gross Domestic Product (GDP) are commonly used by utilities as the main economic indicator in regression modeling instead of disposable income.
- GNP data is more readily available than disposable income data.
- LUMA's use of GNP in the residential regression model is consistent with its approach in regression models for the other customer classes.

I do not agree with Mr. Cao's argument that errors from LUMA's *prior* load forecasts compared to current loads are indicative of the accuracy of LUMA's *current* load forecast in this proceeding. Mr. Cao has not substantiated that his usage of FY2025 historical loads would result in smaller future errors than LUMA's forecast.

D.1.a.ii. Commercial regression model

As noted in Section D.1.a.i, it is not reasonable for LUMA to use different CDD scenarios in the residential and commercial regression models. The use of two different CDD scenarios means the residential and commercial rate class load forecasts use two different weather scenarios. The two regression models should reflect the same future weather scenario. Therefore, LUMA should use the same percentile scenario for CDD in the commercial model that it uses for residential.

LUMA's decision to not adjust the commercial regression to account for the historical impacts of load modifiers is not be reasonable, as this can result in overcounting when the load modifiers are incorporated. The Energy Bureau should direct LUMA to revisit the regression model to consider the historical impact of these load modifiers in future load forecast filings.

Mr. Cao's argument that the commercial regression model should have used electricity price as an independent variable is reasonable, given that changes in electricity price can influence commercial customers to adopt technologies like DG and EE. Mr. Cao's argument that commercial net income should be used as an independent variable is valid, but the current approach of using GNP as the key economic variable is reasonable, as described in Section D.1.a.i.

D.1.a.iii. Industrial regression model

LUMA reasonably chose to exclude the CHP modifier from the industrial regression model, after first estimating its historical impact. This approach avoids double counting the CHP load modifier when it is later subtracted from the industrial class base consumption forecast.

Similar to the residential and commercial regression models, Mr. Cao's argument that the industrial regression model should have used electricity price as an independent variable is reasonable, particularly given that these customers are more likely to adopt CHP if electricity prices increase. Nevertheless, LUMA's decision to model CHP adoption separately as a load modifier based on CHP evaluation data is reasonable, given that it takes time to conduct a CHP evaluation and this forecast is for only a three-year time horizon.

Mr. Cao's argument that a measure of U.S. demand for Puerto Rico's manufactured goods should have been included as an independent variable is valid; however, LUMA's decision to use GNP as the key economic indicator variable is reasonable, for the reasons stated in Section D.1.a.i.

D.1.a.iv. Smaller classes model

LUMA's decision to project consumption for small customer classes of public lighting, agriculture, and other authorities as equal to the current year's estimate, with leap year adjustments, is reasonable given that the relatively constant historical consumption and the small impact of these classes (approximately 2.1% of total LUMA load).

D.1.b. Load modifiers

LUMA's decision to forecast the effects of load modifiers, then apply these effects to the base consumption forecast for each customer class is reasonable. This approach reflects the impacts of

key load modifiers individually. The following subsections discuss comments on the approach for each load modifier.

D.1.b.i. Distributed Generation (DG) and Net Metering (NM)

LUMA's decision to use a Gompertz Growth Model to project residential and commercial PV capacity (kW) adoption is reasonable. The Gompertz Growth Model is commonly used to project uptake of a new technology throughout a population. LUMA's decision to keep industrial and agricultural PV constant is reasonable due to observed stagnation of PV adoption in these classes.

LUMA converted PV capacity to generation in each rate class using class-specific monthly capacity factors. This decision is also reasonable because capacity factors represent actual energy output relative to maximum potential output. Monthly factors reflect differences in potential generation across months of the year as the solar resource changes.

LUMA did not include any direct assumptions on battery storage in the DG forecast. Ms. Estrada noted that empirical data indicates that customers are using their batteries primarily for backup reliability, not daily load-shifting. If this trend continues, the current approach is reasonable because batteries used for reliability only will not have an effect on the consumption forecast.

D.1.b.ii. Combined Heat and Power Systems (CHP)

LUMA's decision to project CHP capacity in the commercial and industrial customer classes, based on data from customers' CHP system evaluations, is reasonable. LUMA conducts CHP system evaluations with customers that are planning to adopt CHP, so this is the best available data for forecasting CHP impacts for the forecast horizon of 2026 to 2028.

Using historical data from before and after installation, LUMA calculated average capacity factors for future CHP customers. This decision is reasonable because LUMA's historical CHP customer data is the best available data source for the how customers in Puerto Rico are using CHP. LUMA's decision to assume an increase in CHP production for each customer in year two of operation is also reasonable, based on the historical consumption data from CHP customers.

D.1.b.iii. Energy Efficiency (EE)

LUMA calculated load reductions from EE for FY2026 to FY2028 based on the assumption that Puerto Rico would achieve the goal of a 30% reduction of electricity by 2040 relative to FY2019. This approach is reasonable because of the information available to LUMA at the time of the forecast. It is also reasonable to reflect LUMA's need to meet the 2040 goal. As described in the expert report of the Energy Bureau's consultant Dr. Asa Hopkins, an alternative approach is to use the Market Baseline and Potential Study ("Potential Study"). The Potential Study was commissioned by the Energy Bureau to reflect the potential near-term EE program size that is realistic for Puerto Rico to achieve. Dr. Hopkins' expert report provides recommended cumulative sales adjustments for energy efficiency programs in the residential and commercial rate classes.

D.1.b.iv. EV charging load

LUMA's decision to use the PR100 study's EV charging data as the basis for the EV charging load modifier is reasonable because the PR100 study is a readily available data source for Puerto Rico.

D.1.c. Generation and peak demand forecast

LUMA's decision to calculate the total annual generation forecast by dividing total annual consumption (sum of all customer classes) by the average efficiency observed in FY2022 through FY2024 is reasonable. The historical system average efficiency (total annual consumption divided by annual generation) has remained relatively constant over time. The short, three-year timeframe of the forecast also means that the system efficiency is likely to remain similar to recent years.

LUMA forecasted annual peak demand by applying historical load factors to the consumption of each customer class. LUMA's approach inappropriately ignores the load shape of the load modifiers. Load modifiers affect usage at different times of day; therefore, a simple load factor without a more detailed load shape cannot capture their impacts on peak demand. In particular, DG likely produces some energy during peak hours that potentially shifts the system peak later in the day. Therefore, I recommend that LUMA include hourly impacts of load modifiers in future forecasts of peak demand.

D.1.d. Monthly distribution and seasonal adjusters

LUMA converted the forecasted consumption, generation, and peak demand annual values to monthly values based on seasonal trends in each month using the U.S. Census X-12 seasonal adjustments. This approach is reasonable because the U.S. Census X-12 program is commonly used to identify seasonal patterns in time-series data like energy consumption.

D.2. Load forecast results

Ms. Estrada described two competing forces on the final load forecast:

- Higher temperatures in Puerto Rico, which have an upward impact on consumption, particularly in the residential customer class
- Increasing integration of self-generation systems (DG, CHP), which have a downward impact on consumption

LUMA addresses the first trend (higher temperature impacts) through a regression model for the residential and commercial customer classes. The second trend, of increasing integration of self-generation systems, is addressed through the DG and CHP load modifiers. As noted in Sections D.1.a.i and D.1.a.ii, the residential and commercial regression models did not address the historical impacts of DG. The number of registered DG customers has increased by a compound annual growth rate of 45.4% from January 2017 to January 2025.⁵² I expect that the regression implicitly includes the effects of increasing amounts of DG in the base consumption forecast, which leads to overcounting when DG is later added as a load modifier.

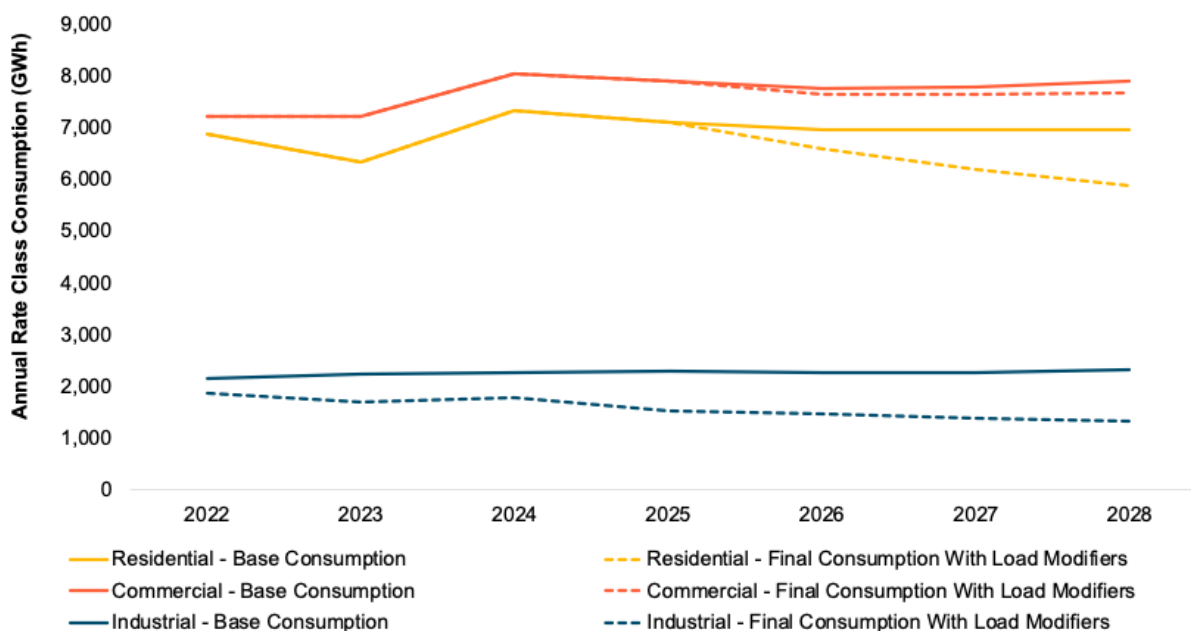
Figure 5 shows a summary of the consumption forecast for each rate class. For the industrial rate class, LUMA considers the effects of CHP separately from base consumption in both the historical consumption data 2022-2025 and the forecast 2026-2028, resulting in distinct trajectories for industrial base consumption and industrial load with modifiers. As noted above, in

⁵² Calculated using the Registered Customers in January 2017 and January 2025 in LUMA Ex. 4.02, "FP approved Load w Modifiers" tab.

the historical data for the residential and commercial regression models, LUMA did not separate out load modifiers like DG.

As shown in Figure 5, LUMA's base consumption forecast results in relatively flat residential, commercial, and industrial consumption from 2026-2028. When load modifiers are included, LUMA's final load forecast results in declining residential, commercial, and industrial consumption from 2026-2028, with the residential and industrial classes experiencing the largest declines. In future load forecast filings, LUMA should consider if the two competing trends make sense in this resulting decrease, given that the base consumption regression may overcount the impacts of load modifiers.

Figure 5: Summary of historical consumption and forecast for each major rate class, including the base consumption and the final consumption with load modifiers



In future load forecast filings, LUMA should also investigate customer price elasticity as an additional variable in the consumption forecast. As noted in Mr. Cao's report, if electricity prices increase as a result of this rate case, customers might adopt self-generation, implement efficiency measures, or decrease usage in response. Future load forecasts should consider effects of potential rate increases from the rate case on the final load forecast.

D.3. Customer count forecast

LUMA reasonably forecasted customer counts with regression models. Regression models are effective statistical techniques for capturing the relationship between independent and dependent variables.

D.4. Billing determinant forecast

LUMA converted energy (kWh) and customer count forecasts for the customer classes (e.g., residential, commercial, industrial) to billing determinant forecasts for each rate class (e.g., GRS,

LRS, GSS) by applying ratios from 2024 historical data, as described in Section B.4. LUMA's approach is reasonable for the three-year forecast horizon, since ratios of the billing determinants of each rate class to billing determinants of each customer class are unlikely to shift significantly.

LUMA's use of static load research data for all demand (kW) billing determinants is problematic. LUMA *forecasts* energy billing determinants, while LUMA leaves demand determinants fixed at *historical* levels, creating misalignment. For residential and industrial customer classes, Ms. Estrada forecasted a decline in energy consumption over the three-year period. Declining energy and static demand billing determinants result in lower load factors of these customer classes by up to 8% in FY2028 compared to FY2026.

E. Recommendations on load forecast and billing determinants

E.1. Load forecast

I recommend that the Energy Bureau adopt LUMA's final load forecast as summarized in Table 2. While there are areas where LUMA can improve its methodology in future forecasts, its current methodology and results are reasonable in totality.

For future load forecast filings, I recommend that the Energy Bureau direct LUMA to correct the deficiencies that I identified in Section D.

First, as described in Sections D.1.a.i and D.1.a.ii, the residential and commercial base consumption regression models use different CDD assumptions. LUMA should align the inputs used in both rate class models to plan for the same future weather scenario.

Second, as described in Sections D.1.a.i, D.1.a.ii, and D.2, the residential and commercial regression models do not account for the historical impact of load modifiers. Because load modifiers are already embedded in the historical data used in the regression models, adding load modifiers again in the final consumption forecast is overcounting their impact. LUMA should revise its residential and commercial regressions to account for the historical impact of load modifiers, especially DG. As described in Section D.1.b.iii, Dr. Hopkins' expert report provides recommended values for energy efficiency program savings.

Third, as described in Section D.1.c, the demand forecast should consider the hourly impacts of load modifiers. Load modifiers impact the hour of peak demand. As DG adoption increases, it shifts peak demand to later in the day.

Fourth, as described in Sections D.1.a.i, D.1.a.ii, D.1.a.iii, and D.2, the consumption forecast should investigate customer price elasticity, by adding electricity price as a regression variable. LUMA should consider how electricity rates affect the final consumption forecast.

E.2. Billing determinants

LUMA's approach to forecasting energy (kWh) and customer count (#) billing determinants is reasonable because LUMA ties them to its load forecast. LUMA's approach to forecasting demand billing determinants is problematic because it relies only on historical data.

Because of this, the Energy Bureau should direct LUMA to periodically (e.g., at least annually) update its demand billing determinants to ensure that they reflect the most recent changes to customer loads. LUMA should then use these updated billing determinant values for any calculations that rely on billing determinants such as electricity rates. In other words, the Energy Bureau should not pre-approve rates that are based on billing determinant forecasts for which LUMA will have improved information in the future.

Cost Allocation and Revenue Allocation

F. Issue background

A utility's "annual revenue requirement" is the total revenue that the utility must recover from customers each year to cover all of its costs. Revenue allocation refers to allocating, among customer classes, the responsibility for producing that revenue. How the utility allocates revenues affects the rates paid by the customers within each class, but it does not affect the total revenue that the utility collects. Customer classes are groups of customers with similar characteristics in why they use electricity (e.g., to live, run a business, or run a manufacturing plant); how much they use; their usage patterns over a day, week, season or year; and level of customer sophistication. Examples of customer classes are residential, commercial, industrial, and streetlighting.

F.1. Cost allocation

There are multiple accepted methods for allocating revenues. The most commonly used methods adhere to the principle of *cost causation* – how each customer class causes costs to the utility. The cost-causation principle aligns with fairness, since it is fair for customers to bear the costs that they cause.

To determine the cost caused by each customer class, utilities perform a Cost-of-Service Study (COSS). A COSS involves three major steps:

Functionalization: This step separates the utility's revenue requirement into the utility's major "functions," such as generation, transmission, distribution, and billing.

Classification: This step identifies the customer actions that cause costs within each functionalized category. The classes of costs are energy, demand, and number of customers. For example, fuel costs are caused when customers consume energy, so the fuel cost portion of generation costs are classified to energy. The cost of meters are caused by the number of customers, so are classified to customer count. Some categories, such as power plant costs, are driven by a combination of how much energy customers consume *and* how much customers consume during the period of peak demand—so those costs get classified in part to energy and in part to demand.

Allocation: Once costs have been functionalized and classified, it is necessary to allocate the costs to each customer class based on each class's billing determinants. Billing determinants are the factors representing cost causation: kWh for energy use, kW for demand, and then number of customers. For example, a customer class that consumes 30% of total system energy would be allocated 30% of all energy-classified costs.

Utilities use various methods to functionalize, classify, and allocate costs. No one method reflects cost causation perfectly. To carry out these steps, the Energy Bureau applies judgment to the data on consumption, demand, and number of customers.

F.2. Revenue allocation

A utility might design rates that cause the total revenues collected from each customer class to differ from the cost allocation calculated through the COSS. Reasons for these differences include a desire to introduce rate changes gradually, to support policy objectives such as economic development, or to offer a deliberate subsidy for certain customer classes. The process that determines the total costs to be collected from each customer class is called *revenue allocation*. To the extent that revenue allocations differ from cost allocations, the utility and the Energy Bureau should have a clear understanding of the cause of any differences.

G. Position of the applicant

In this section, I summarize the position of the applicant on topics related to cost and revenue allocation. I evaluate the position of the applicant separately in Section I.

In its July 3, 2025 application, LUMA proposed cost-of-service studies (COSS) and revenue allocations for fiscal years 2026 through 2028. As explained by Mr. Alejandro J. Figueroa Ramírez, Chief Regulatory Office at LUMA, “[r]ate design occurs at the utility level.”⁵³ LUMA’s proposed COSS, revenue allocation, and rate design included LUMA, Genera PR LLC’s (“Genera”), and PREPA HoldCo, and PREPA HydroCo LLC’s (“PREPA HydroCo”) revenue requirements.⁵⁴ Mr. Sam Shannon, Associate Director at Guidehouse, presented direct testimony in support of LUMA’s cost-of-service study (COSS), revenue allocation, and rate design proposals.

The following sections detail LUMA’s proposed COSS methodology, revenue allocation methodology, and COSS and revenue allocation results.

G.1. Cost-of-Service Study methodology

LUMA’s proposed cost-of-service study (COSS) contained three major calculation steps: functionalization, classification, and allocation. The following subsections detail each step of LUMA’s proposed methodology. Each subsection concludes with a summary table to provide an overview of the detailed information presented throughout the subsection.

G.1.a. Functionalization

First, LUMA functionalized costs to the categories of production, transmission, distribution, customer service, and administrative and general. LUMA also sub-functionalized distribution into primary distribution and secondary distribution. Mr. Shannon explained that the FERC Uniform System of Accounts serves as the standard cost functionalization scheme for utilities in the United States; however, PREPA’s accounting system is noncompliant with the FERC Uniform System of Accounts.⁵⁵ Given the limitations of PREPA’s accounting system, Mr. Shannon functionalized costs based on the roles of the operators:

⁵³ LUMA Ex. 1.0 (7.03.25) Testimony Alejandro Figueroa, p.3, ll.59-60.

⁵⁴ LUMA, Genera, PREPA HoldCo, and PREPA HydroCo are collectively referred to as “the operators.”

⁵⁵ LUMA Ex. 20.0, p.6, ll.80-81, 87.

- Genera and PREPA HydroCo's costs to the production function
- PREPA's HoldCo costs to the administrative and general function
- LUMA's costs to transmission, distribution, customer service, and administrative and general functions,⁵⁶ as detailed below.

LUMA's accounting system allowed Mr. Shannon to identify distinct transmission capital expenses and distribution capital expenses; therefore, LUMA assigned these expenses to distribution and transmission functions.

LUMA functionalized substation capital expenses to the transmission function. Mr. Shannon clarified that the substation expenses "include substations that provide support to the distribution system; however, the costs cannot be separated at this time," so therefore LUMA did not functionalize any substation capital costs to the distribution function⁵⁷

Similarly, LUMA's accounting system did not distinguish between transmission and distribution operating and maintenance (O&M) expenses. Mr. Shannon therefore functionalized LUMA's O&M expenses between transmission and distribution based on the ratio of miles of transmission lines versus miles of distribution lines, with a factor of 3 applied to the miles of transmission lines.⁵⁸ Mr. Shannon clarified that "there are no supporting calculations for the 3x cost adder; it is a reasonable estimate based on Mr. Shannon's judgement."⁵⁹

As Mr. Shannon explained:

The distribution system can be broken into two parts, the primary and secondary systems. Primary distribution lines are energized at higher voltages and are reduced or "stepped down" to secondary voltages for distribution to smaller customers."⁶⁰ LUMA sub-functionalized some distribution expenses (Materials and Supplies and Vegetation Management O&M expenses, and Distribution Line Rebuild and Distribution Pole and Conductor Repair capital expenses) between primary and secondary distribution "in the same proportion as miles of primary and secondary distribution lines."⁶¹

LUMA assigned LUMA's customer service costs to the customer service function. Mr. Shannon noted that "the customer service function includes the plant and expenses associated with providing services to customers, such as meters, billing, and collection and information and services."⁶²

⁵⁶ LUMA Ex. 20.0, p.7, ll.109-114.

⁵⁷ PC-of-LUMA-COST-ALL-14.

⁵⁸ LUMA Ex. 20.0, p.7, ll.114-117 and PC-of-LUMA-COST_ALL-6, part a.

⁵⁹ PC-of-LUMA-COST_ALL-6, part c.

⁶⁰ LUMA Ex. 20.0, p.15, ll.287-290.

⁶¹ LUMA Ex. 20.0, p.14, ll.293-294, LUMA Schedule K-1 Cost Allocation, p.2, ll.41-44, 55-58, p.4, ll. 21-24.

⁶² LUMA Ex. 20.0, p.7, ll.103-107.

Mr. Shannon functionalized LUMA's support services costs to the administrative and general function. The administrative and general function includes "management costs, administrative buildings, etc., that cannot be assigned to other major cost functions."⁶³ Within administrative and general costs, LUMA included costs such as IT Service Agreements, Storm Outage Reserve, LUMA Operator Fee, Utilities and Rents, and Legal Services.⁶⁴

G.1.b. Classification

Mr. Shannon explained that "[c]ost classification attempts to answer the question: "Why did a utility build the infrastructure and incur the costs it did?"⁶⁵

Mr. Shannon classified costs into five categories:⁶⁶

- Demand costs vary with the demand (kW) imposed by the customer.
- Energy costs vary with the energy (kWh) provided to the customer.
- Customer costs vary with the number of customers served.
- Labor costs vary based on the amount of labor costs allocated to each customer class.
- Revenue costs are "a function of the total revenue to the utility."⁶⁷

The nature of the first three categories is distinct from the last two, because customer class billing determinants directly measure demand, energy, and number of customers (e.g., each class's kWh energy use as a share of the total system). The last two categories (labor and revenue) are derived by LUMA from the first three categories. For example, LUMA allocated labor-classified costs based on the amount of labor costs within each function that LUMA allocated to each customer class using demand, energy, and customer. The allocation section of this report describes labor and revenue allocation factors in detail.

G.1.b.i. Production

Production costs include both O&M, capital, and fuel and purchased power costs. LUMA classified these production cost categories partially to energy and partially to demand.

LUMA split production O&M costs between energy and demand classifications using an "average-excess" methodology. Mr. Shannon described the average-excess calculation as follows:

The peak PREPA system load is divided by the sum of the peak load and the average monthly load to calculate the proportion of demand-classified production costs. This formula is designed so that for a utility with a 100 percent load factor, the demand/energy split is 50-50.⁶⁸

⁶³ LUMA Ex. 20.0, p.7, ll.103-107.

⁶⁴ LUMA Schedule K-1 Cost Allocation, p.3, ll.9-30 (#2).

⁶⁵ LUMA Ex. 20.0, p.8, ll.125-126.

⁶⁶ LUMA Ex. 20.0, p.7-8, ll.120-121.

⁶⁷ LUMA Ex. 20.0, p.15, ll.301-302.

⁶⁸ LUMA Ex. 20.0, p.7, ll.151-152.

LUMA calculated the “average monthly load” component by dividing the sum of the monthly system peak loads by 12.⁶⁹

For production capital costs, Mr. Shannon explained that he classified “the peaker plant costs to demand and the remainder to energy” and that the “HydroCo costs are all classified as energy.”⁷⁰ In response to ROIs, LUMA provided a summary of the heat rate, capacity factor, and installation year of all generators, with generators categorized as peaker generators, baseload generators, and renewable generators.⁷¹

LUMA classified fuel and purchased power costs to energy.⁷²

G.1.b.ii. Transmission

LUMA classified all transmission and substation costs to demand. Mr. Shannon explained that “[t]he primary criteria when constructing the bulk power grid is ensuring that the grid can handle the peak load requirements. Therefore, LUMA classified the entire transmission system as peak demand.”⁷³

G.1.b.iii. Distribution

LUMA classified distribution costs partially to customer and partially to demand, with one select cost classified to energy as described below.

LUMA proposed that “[d]istribution poles, conductors, and line transformers are classified according to the customer/demand split to reflect the dual nature of the distribution network.” Mr. Shannon proposed using a minimum system study to determine the customer/demand split for relevant costs. As Mr. Shannon explained:

“[The minimum system study] takes the smallest unit purchased by the utility and applies that unit cost to the total amount of infrastructure. The result is the cost of a distribution network assuming that the utility only installed the minimum infrastructure to connect its customers, hence the customer-classified portion. Costs above this amount are incurred, in theory, to support peak loads and are classified as demand.”⁷⁴

Mr. Shannon considered three types of costs in his minimum system study: conductors, distribution poles, and line transformers. Table 5 summarizes the minimum item within each of these categories, their unit cost, and the total asset count. Mr. Shannon calculated the minimum system cost by multiplying the unit cost by the total asset count.

⁶⁹ LUMA Schedule K-1 Minimum Sys FY2026 (7.03.25), ll. 24-35.

⁷⁰ LUMA Ex. 20.0, p.9, ll.157-160.

⁷¹ PC-of-LUMA-COST_ALL-8, Attachment 1.

⁷² LUMA Schedule K-1 Cost Allocation, p.2, ll.18.

⁷³ LUMA Ex. 20.0, p.10, ll.173-175, LUMA Schedule K-1 Cost Allocation, p.4, ll.11-14.

⁷⁴ LUMA Ex. 20.0, p.10, ll.185-190.

Table 5: Minimum system study assumptions provided by LUMA⁷⁵

Distribution Component	Minimum Item	Unit Cost ⁷⁶ (\$/unit)	Total Asset Count	Minimum Cost (\$)	Plant Balance (estimate) ⁷⁷ (\$)
Conductors	AWG #2 CU Bare	\$1.43/ft	87,040,800 ft	\$124,468,344	\$1,085,255,892
Distribution Poles	Wood, 40 ft, class 2	\$507.53 /pole	665,000 poles	\$337,507,450	\$582,313,259
Line Transformers	15 kVA	\$1,109 /transformer	148,107 transformers	\$164,250,663	\$481,375,098
Total				\$626,226,457	\$2,148,944,249
Minimum Cost as percentage of Plant Balance				29.14%	

Mr. Shannon calculated the customer share as the ratio of total minimum system cost to the total plant balance across all three distribution components. This calculation resulted in a customer share of 29.14% and a demand share of 70.86%.⁷⁸ Mr. Shannon noted that “the results of the minimum system study fell within what I considered to be the range of reasonableness”⁷⁹ and elaborated that “for customer-classified costs, a range between 20 and 70 percent would be within expected values.”⁸⁰

Mr. Shannon classified Control Center & Buildings capital expenses to energy and Enabling capital expenses to demand.⁸¹ Mr. Shannon noted that “based on the description of control station costs, these items could be considered similar to administrative costs that an independent system operator (ISO) would have. Therefore, allocating these costs by production energy is a reasonable approach.”⁸²

Within LUMA’s rate design schedules, LUMA has only used a customer/demand split to split Materials and Supplies and Vegetation Management O&M expenses between customer and demand.⁸³ LUMA classified all distribution capital expenses as demand. In response to ROIs, LUMA

⁷⁵ Derived from LUMA Schedule K-1 Minimum Sys, p.1, ll.1-5.

⁷⁶ Unit costs and total asset counts were provided to Mr. Shannon by LUMA distribution asset management staff, as described in PC-of-LUMA-COST-ALL_11, part b.

⁷⁷ Based on PREPA Depreciation Study of Electric Plant in Service as of June 30, 2019, June 30, 2020, and June 30, 2021, Appendix A, as described in PC-of-LUMA-COST_ALL-11.

⁷⁸ LUMA Schedule K-1 Minimum Sys, p.1, ll.1-5. These values differ slightly (<1%) from the values quoted in LUMA Ex. 20.0, p.11, ll.194-195.

⁷⁹ LUMA Ex. 20.0, p.11, ll.195-196.

⁸⁰ PC-of-LUMA-COST-ALL-11, part c.

⁸¹ LUMA Schedule K-1 Cost Allocation, p.4, ll.30-47.

⁸² PC-of-LUMA-COST-ALL-14.

⁸³ Outside of LUMA’s COSS, they also classified costs to a customer classification within a “functionalized cost analysis” for the purpose of informing its proposed fixed monthly customer

explained that “[g]iven the cash-financed nature of PREPA at this time, Mr. Shannon chose to exclude the capital spend from the customer/demand split to avoid overclassifying customer-related costs.”⁸⁴

G.1.b.iv. Customer service

LUMA classified most O&M and capital costs in the customer service function as customer-related costs.⁸⁵ LUMA explained that these expenses arose from providing service to customers and collecting revenue, and the cost “directly results from the number of customers, and, therefore, all the related costs are customer-classified costs.”⁸⁶ The Allocation section of this report details of how these costs are allocated to customer classes.

LUMA classified “Excess Expenditures” as energy-related and “Bad Debt” expense as revenue-related.⁸⁷ Mr. Shannon explained that bad debt is “also called uncollectible accounts” and “is a cost of running a business and is directly calculated as a function of the total revenue to the utility.”⁸⁸

G.1.b.v. Administrative and General costs

LUMA classified administrative and general costs using a mixed approach based on the cost category.

LUMA noted that some costs “are incurred to support the employees of the utility, and therefore, the costs should be classified as labor-related.”⁸⁹ LUMA classified most O&M costs such as IT service agreements, utilities and rents, legal services, and professional and technical outsourced services as labor-related.

LUMA also noted that “some of the [administrative and general costs] could also be viewed as resulting from the fact that the utility has regulatory and other professional obligations and should be classified as revenue-related.”⁹⁰ LUMA classified PREPA Restructuring & Title III and FOMB advisor costs as revenue-related.

LUMA did not classify Property and Casualty Insurance and LUMA and General Operator Fees to a particular category but instead allocated these costs based on the overall allocation of capital expenses of different functions. The Allocation section of this report describes the allocation factors for these expenses in detail.

LUMA classified Storm Outage Reserve to energy.

charge. The method LUMA used to classify customer-related costs in its COSS differed from the approach they used in its rate design process.

⁸⁴ PC-of-LUMA-COST_ALL-10, part c.

⁸⁵ LUMA Schedule K-1 Cost Allocation, p.3, ll.1-13 and p.5, ll.1-9.

⁸⁶ LUMA Ex. 20.0, p.11, ll.203-204.

⁸⁷ LUMA Schedule K-1 Cost Allocation, p.3, ll.14-16.

⁸⁸ LUMA Ex. 20.0, p.15, ll.301-302.

⁸⁹ LUMA Ex. 20.0, p.11, ll.210-214.

⁹⁰ LUMA Ex. 20.0, p.11, ll.210-214.

LUMA classified most A&G capital expenses to labor, except for Renewables Integration and Generation Studies, which LUMA classified to energy.⁹¹

G.1.b.vi. Summary of classification methodology

Table 6 summarizes LUMA's proposed classification methodology of costs to demand, energy, customer, revenue, or labor classifications.

Table 6: Summary of LUMA's proposed classification methodology to demand, energy, customer, revenue, and labor classifications.

Costs	Classification	Source
Production		
General operating expenses and labor costs	Average-excess demand/energy split	Ex. 20.0, p.9, ll.156
General capital expenses	Peaker plant costs to demand All other costs to energy	Ex. 20.0, p.9, ll.156-158
All HydroCo expenses	Energy	Ex. 20.0, p.9, ll.159-160
Purchased Power	Energy	LUMA Schedule K-1 Cost Allocation, p.2, ll.19
Fuel	Energy	LUMA Schedule K-1 Cost Allocation, p.2, ll.18
Transmission		
Transmission O&M and capital expenses	Demand	Ex. 20.0, p.10, ll.173-175, LUMA Schedule K-1 Cost Allocation, p.4, ll.11-14
Substation capital expenses	Demand	LUMA Schedule K-1 Cost Allocation, p.4, ll.16-19
Distribution		
Materials and Supplies and Vegetation Management O&M expenses	Customer/demand split based on minimum system study	LUMA Schedule K-1 Cost Allocation, p.2, ll.41-44, 55-59
All distribution O&M expenses (except expenses in previous row)	Demand	LUMA Schedule K-1 Cost Allocation, p.2, ll.40-60
Control Center and Buildings capital expenses	Energy	LUMA Schedule K-1 Cost Allocation, p.4, ll.30-34
Enabling capital expenses	Demand	LUMA Schedule K-1 Cost Allocation, p.4, ll.35-47
All other distribution capital expenses	Demand	LUMA Schedule K-1 Cost Allocation, p.4, ll.21-27
Customer and Service		

⁹¹ LUMA Schedule K-1 Cost Allocation, p.5, ll.12-25.

Excess Expenditures O&M expense	Energy	LUMA Schedule K-1 Cost Allocation, p.3, ll.14
Bad Debt O&M expense	Revenue	LUMA Schedule K-1 Cost Allocation, p.3, ll.16
All customer service O&M expenses (except expenses in previous 2 rows)	Customer	LUMA Schedule K-1 Cost Allocation, p.3, ll.1-13
All customer service capital expenses	Customer	LUMA Schedule K-1 Cost Allocation, p.5, ll.1-9
Administrative and General (A&G) Costs		
A&G Property and Casualty Insurance, LUMA and General Operator Fees	Allocated based on capital expense allocation of different functions ⁹²	LUMA Schedule K-1 Cost Allocation, p.3, ll.12 (#2)
Storm Outage Reserve	Energy	LUMA Schedule K-1 Cost Allocation, p.3, ll.22 (#2)
PREPA Restructuring & Title III, FOMB Advisor Costs	Revenue	LUMA Schedule K-1 Cost Allocation, p.3, ll.26-28 (#2)
All A&G O&M expenses (except expenses in previous 3 rows)	Labor	LUMA Schedule K-1 Cost Allocation, p.3, ll.9-21 (#2)
Renewables Integration & Generation Studies capital expense	Energy	LUMA Schedule K-1 Cost Allocation, p.5, ll.12
All A&G capital expenses (except expenses in previous row)	Labor	LUMA Schedule K-1 Cost Allocation, p.5, ll.13-25

G.1.c. Allocation

Mr. Shannon explained that “[t]he final step in performing a COSS is to allocate the costs across the customer classes.”⁹³

LUMA calculated allocation factors by measuring a specific metric for each customer class and then dividing that by the total metric across all customer classes. For example, LUMA calculated an energy allocator as energy consumption by customer class divided by total energy consumption across all customer classes. For brevity, the descriptions in this section do not include the denominator (e.g., total energy consumption across all customer classes). After the description of each allocation factor, this section includes an allocation factor name in brackets (for example (“Energy – Consumption” allocator)) for ease of reference.

⁹² See detailed explanation in Allocation section.

⁹³ LUMA Ex. 20.0, p.12, ll.217-220.

G.1.c.i. Production

LUMA allocated energy-classified production costs using energy consumption by customer class, grossed up for losses (“Energy – Generation” allocator).⁹⁴ LUMA allocated demand-classified production costs using a 12 CP (coincident peak) allocator (“Demand – 12 CP” allocator). Mr. Shannon explained that “[a]ll coincident peak allocators split costs based on each customer class’s contribution to the system peak” and that the 12 CP allocator “take[s] the twelve-monthly system peaks and add[s] them together.”⁹⁵

G.1.c.ii. Transmission

LUMA allocated transmission O&M and capital expenses to customer classes using a 1 CP allocator that considers customer class contribution to the single highest system peak for the year (“Demand – 1 CP” allocator).⁹⁶

LUMA proposed using a modified 1 CP allocator to allocate substation capital expenses (“Demand – 1CP Substation” allocator). The “Demand – 1CP Substation” allocator also considers customer class contribution to the single highest system peak for the year but excludes the large C&I customer classes (GST, TOU-T, LIS, and PPBB) from the total system load and assigns no costs to those classes.⁹⁷

G.1.c.iii. Distribution

LUMA allocated customer-classified distribution costs using a weighted-customer allocator (“Weighted-Customer” allocator) that “uses the number of customers in each customer class as the basis of the allocation” and “assigns different weights to customer counts, with residential customers as the base customer.”⁹⁸ Table 7 summarizes LUMA’s proposed customer class weightings for the customer allocator.

Table 7: Customer class weighting for Customer allocator⁹⁹

Rate Class	Residential	Small C&I	Medium C&I	Large C&I	Lighting and Other
Weight	1	3.5	10	25	50
Notes			Excluded for primary distribution costs	Excluded for primary and secondary distribution costs	

⁹⁴ LUMA Ex. 20.0, p.12-13, ll.236-242.

⁹⁵ LUMA Ex. 20.0, p.13, ll.244-249.

⁹⁶ LUMA Ex. 20.0, p.13, ll.246-247.

⁹⁷ LUMA Schedule K-1 Cost Allocation, p.4, ll.11-19.

⁹⁸ LUMA Ex. 20.0, p.14, ll.269-275.

⁹⁹ LUMA Schedule K-2 Allocators, p.1, ll.3-11.

LUMA allocated demand-classified distribution costs using a 12 NCP (non-coincident peak) demand allocator (“Demand – NCP” allocator), which LUMA further explained is “made up of the individual customer class [monthly] peak demands, regardless of when they occurred in relation to the system peak.”¹⁰⁰

For distribution costs that LUMA functionalized to primary and secondary distribution, LUMA proposed variants of the Weighted-Customer and NCP allocators. LUMA excluded large C&I customers classes (GST, TOU-T, LIS, and PPBB) from the “Primary” variant and excluded medium and large C&I customers classes (GSP, TOU-P, GST, TOU-T, LIS, and PPBB) from the “Secondary” variant.¹⁰¹

LUMA allocated energy-classified distribution costs using the “Energy – Generation” allocator.¹⁰²

G.1.c.iv. Customer service

LUMA allocated customer-classified customer service expenses with the “Weighted-Customer” allocator. LUMA allocated energy-classified customer service costs (Excess Expenditures) using energy consumption by customer class, not grossed up for losses (“Energy – Consumption” allocator). LUMA allocated revenue-classified customer service costs (Bad Debt) using the total revenue from base rates (without riders) generated from each customer class at present rates (“Total Revenue” allocator).¹⁰³

G.1.c.v. Administrative and General costs

LUMA allocated some administrative and general expenses with a labor allocator (“Labor” allocator). LUMA calculated the “Labor” allocator using the Salaries, Wages and Benefits for each functionalized category that were allocated using the classification factors relevant to each function.¹⁰⁴

LUMA allocated Storm Outage Reserve costs with the “Energy – Consumption” allocator, Renewables Integration and Generation studies costs with the “Energy – Generation” allocator and PREPA Restructuring & Title III and FOMB Advisor costs with the “Total Revenue” allocator.

Finally, LUMA allocated some costs based on total allocated expenses within other categories. These costs included:

- LUMA allocated Property and Casualty Insurance costs based on overall capital expense allocated to each customer class;
- LUMA allocated LUMA’s operator fees based on T&D O&M expenses allocated to each customer class;

¹⁰⁰ LUMA Ex. 20.0, p.14, ll.276-278.

¹⁰¹ LUMA Schedule K-2 Allocators, p.1, ll.5-9.

¹⁰² LUMA Schedule K-1 Cost Allocation, p.4, ll.30-47.

¹⁰³ LUMA Schedule K-1 Cost Allocation, p.3, ll.14-16.

¹⁰⁴ LUMA Ex. 20.0, p.16, ll.313-315.

- LUMA allocated Genera’s operator fees based on overall production expense allocated to each customer class.¹⁰⁵

G.1.c.vi. Summary of allocation methodology

Table 8 summarizes LUMA’s proposed allocation factors.¹⁰⁶ Table 9 summarizes the allocation factors that LUMA proposed to use for all functionalized and classified costs.

Table 8: Description of allocation factors

Allocator	Description	Source
Energy - Generation	Energy consumption by customer class, grossed up for losses.	Ex. 20.0, p.12-13, ll.236-242, LUMA Schedule K-2 Allocators, p.1, ll.23
Energy – Consumption (Sales)	Energy consumption by customer class, not grossed up for losses.	LUMA Schedule K-2 Allocators, p.1, ll.17(#2)
Demand – 12 CP	Customer class contribution to twelve monthly system peaks, summed across all months.	Ex. 20.0, p.13, ll.244-249, LUMA Schedule K-2 Allocators, p.1, ll.19
Demand – 1CP	Customer class contribution to the single highest annual system peak	LUMA Schedule K-2 Allocators, p.1, ll.12
Demand – 1 CP, Substation	Customer class contribution to the single highest annual system peak. The large C&I customer classes (GST, TOU-T, LIS, and PPBB) are excluded.	LUMA Schedule K-2 Allocators, p.1, ll.16
Demand – NCP ¹⁰⁷	Individual customer class monthly peak demands, summer across all months, regardless of when they occurred in relation to the system peak	Ex. 20.0, p.14, ll.276-278, LUMA Schedule K-2

¹⁰⁵ LUMA Schedule K-1 Cost Allocation, p.3, ll.9-30 (#2), p.5, ll.12.

¹⁰⁶ Allocation factors are calculated by measuring and calculating a specific metric for each customer class and then dividing that by the total metric across all customer classes. For examples, an energy allocator could be calculated as energy consumption by customer class divided by total energy consumption across all customer classes. For brevity, the descriptions in Table 8 do not include a description of the denominator in each calculation unless it is something other than the total metric across all customer classes.

¹⁰⁷ There are “Primary” and “Secondary” variations of 12 NCP and Weighted-Customer allocators. The “Primary” variant excludes large C&I customers classes (GST, TOU-T, LIS, and PPBB). The “Secondary” variant excludes medium and large C&I customers classes (GSP, TOU-P, GST, TOU-T, LIS, and PPBB).

		Allocators, p.1, ll.3 (#1)
Weighted-Customer ¹⁰⁷	Number of customers in each customer class, with weights assigned to customer counts of each customer class, as shown in Table 7.	Ex. 20.0, p.14, ll.269-275
Total Revenue	Total base revenue (without riders) from each customer class at present rates	LUMA Schedule K-1 Cost Allocation, p.3, ll.16 (#1)
Capital Expense	Each customer class's allocated portion of capital expenses ¹⁰⁸	LUMA Schedule K-1 Cost Allocation, p.5, ll.29
Labor	Each class's allocated portion of Salaries, Wages and Benefits expenses from production, transmission, distribution, and customer service functions ¹⁰⁹	LUMA Schedule K-1 Cost Allocation, p.3, ll.6 (#2)
T&D O&M Expense	Each customer class's allocated portion of T&D O&M expense	LUMA Schedule K-1 Cost Allocation, p.3, ll.24 (#2)
Production O&M Expense	Each customer class's allocated portion of production O&M expense	LUMA Schedule K-1 Cost Allocation, p.3, ll.22 (#2)

Table 9: LUMA's proposed allocation factors for costs by function. Some allocation factors are only applied to select costs (shown in brackets).

Function	Energy	Demand	Customer	Other Allocators
Production	Energy - Generation	12CP		
Transmission		1 CP 1 CP – Substation (Substation only)		
Distribution	Energy – Generation (Control Center & Buildings only)	- NCP – Primary - NCP – Secondary - NCP (Enabling expenses only)	Weighted-Customer – Primary	

¹⁰⁸ Classification and allocation of capital expenses differs by function. See details of capital expense classification and allocation in Table 8 and Table 9.

¹⁰⁹ Classification and allocation of Salaries, Wages and Benefits expenses differ by function. See details of O&M classification and allocation in Table 8 and Table 9.

			Weighted-Customer – Secondary	
Customer Service	Energy – Consumption (Excess Expenditures only)		Weighted-Customer	Total Revenue (Bad debt expense only)
Administrative and General	- Energy - Sales (Storm Outage Reserve only) - Energy – Generation (Renewables Integration & Generation Studies capital expense only)			- Labor - Capital expense (Property and Casualty Insurance only) - Total Revenue (PREPA Restructuring & Title III only) - T&D O&M Expense (LUMA Operator Fee only) - Production O&M Expense (General Operator Fee only)

G.2. Revenue allocation methodology

LUMA proposed the following three goals for the revenue allocation:

- “no customer class shall receive a decrease from present rates.”
- “low-income residential customers’ increase should be capped at a maximum of 30 percent.”
- “no class should receive an increase greater than two times the overall utility percentage increase.”¹¹⁰

Mr. Shannon noted that his goals “reflect rate design principles of gradualism and maintaining an embedded discount for residential customers....Gradualism is an industry-standard policy objective, reflected in Bonbright’s rate design principle number five...The discount for [residential] low-income classes was reiterated in the 2017 rate order from the Energy Bureau as a matter of policy for the Commonwealth.”¹¹¹ Mr. Shannon also explained that he is “using his best

¹¹⁰ LUMA Ex. 20.0, p.17, ll.335-339.

¹¹¹ The ROI response says “non-Residential.” I assume this is in error.

judgement to achieve a revenue allocation that adhered to the goals described above. The goals provided guiderails and limitations in how the revenue requirements would be collected from the customer classes.”¹¹²

Mr. Shannon then explained that his revenue allocation follows the COSS generally but the “COSS is not a prescriptive for setting revenue allocation” and that “revenue allocation is at its core a policy function. There are other considerations that a regulator might rely on to make revenue allocation decisions outside of the COSS results.”¹¹³

Mr. Shannon also noted that while the COSS showed a large increase in rates for the residential class, “assigning the residential customers such a large increase in year one would violate the third principle which aims to moderate customer class increases.” Mr. Shannon explained that he chose to spread the rate increase for residential customers over three years, rather than implement a single large jump in rates, which “required some of the other classes, particularly transmission-service customers, to take higher increases in the initial year.”¹¹⁴

G.3. Cost-of-Service Study (COSS) and revenue allocation results

Table 10, Table 11, and Table 12 below show the results of LUMA’s proposed COSS and revenue allocation. These tables show the total revenue allocation at present rates, the cost allocation based on the COSS, and LUMA’s proposed revenue allocation. These tables show both the dollar amount and the percentage of the total revenue requirement LUMA proposes to allocate to each rate class.

Table 10: FY2026 revenue allocation at present rates, cost allocation from COSS, and revenue allocation at proposed rates.

Customer Class	Revenue Allocation at Present Rates ¹¹⁵		Cost Allocation from COSS ¹¹⁶		Revenue Allocation at Proposed Rates ¹¹⁷	
	\$	%	\$	%	\$	%
Residential (GRS)	\$1,355,950,810	34.45%	\$2,115,700,378	39.41%	\$1,941,034,636	36.15%
Low-Income Residential (LRS, RH3, RFR)	\$181,179,599	4.60%	\$281,219,291	5.24%	\$214,736,264	4.00%
Small Commercial (GSS, USSL, CATV)	\$586,144,779	14.89%	\$767,382,792	14.29%	\$800,406,197	14.91%

¹¹² PC-of-LUMA-REV_ALL-2.

¹¹³ LUMA Ex. 20.0, p.18, ll.345-351.

¹¹⁴ LUMA Ex. 20.0, p.20, ll.369-378.

¹¹⁵ LUMA Ex. 20.0, p.17, ll.335-337.

¹¹⁶ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2026-AUGUST 13 2025 FINAL REV.

¹¹⁷ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2026-AUGUST 13 2025 FINAL REV.

Medium Commercial (GSP, TOU-P)	\$991,260,218	25.18%	\$1,296,097,383	24.14%	\$1,406,718,850	26.20%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$705,668,099	17.93%	\$767,399,665	14.29%	\$848,440,577	15.80%
Lighting (PLG, LP-13)	\$110,253,311	2.80%	\$126,235,609	2.35%	\$149,826,295	2.79%
Other (GAS)	\$5,534,023	0.14%	\$15,028,295	0.28%	\$7,715,346	0.14%
Total Utility	\$3,935,990,840	100%	\$5,369,063,413	100%	\$5,368,878,166	100%

Table 11: FY2027 revenue allocation at present rates, cost allocation from COSS, and revenue allocation at proposed rates.

Customer Class	Revenue Allocation at Present Rates ¹¹⁸		Cost Allocation from COSS ¹¹⁹		Revenue Allocation at Proposed Rates ¹²⁰	
	\$	%	\$	%	\$	%
Residential (GRS)	\$1,310,798,420	33.49%	\$2,187,644,808	39.36%	\$1,961,181,342	35.28%
Low-Income Residential (LRS, RH3, RFR)	\$176,304,786	4.50%	\$290,440,838	5.22%	\$213,580,278	3.84%
Small Commercial (GSS, USSSL, CATV)	\$598,105,293	15.28%	\$815,604,050	14.67%	\$875,038,429	15.74%
Medium Commercial (GSP, TOU-P)	\$1,010,129,469	25.81%	\$1,350,124,685	24.29%	\$1,499,460,245	26.98%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$704,156,170	17.99%	\$761,800,201	13.70%	\$850,248,089	15.30%
Lighting (PLG, LP-13)	\$108,711,113	2.78%	\$136,349,797	2.45%	\$150,818,375	2.71%
Other (GAS)	\$5,661,034	0.14%	\$16,732,121	0.30%	\$8,330,518	0.15%
Total Utility	\$3,913,866,284	100%	\$5,558,696,500	100 %	\$5,558,657,275	100 %

¹¹⁸ LUMA Ex. 20.0, p.17, ll.335-337.

¹¹⁹ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2027-AUGUST 13 2025 FINAL REV.

¹²⁰ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2027-AUGUST 13 2025 FINAL REV.

Table 12: FY2028 revenue allocation at present rates, cost allocation from COSS, and revenue allocation at proposed rates.

Customer Class	Revenue Allocation at Present Rates ¹²¹		Cost Allocation from COSS ¹²²		Revenue Allocation at Proposed Rates ¹²³	
	\$	%	\$	%	\$	%
Residential (GRS)	\$1,264,035,486	32.58%	\$2,175,218,039	39.23%	\$1,999,097,427	36.06%
Low-Income Residential (LRS, RH3, RFR)	\$171,068,154	4.41%	\$288,045,196	5.20%	\$216,048,434	3.90%
Small Commercial (GSS, USSL, CATV)	\$609,169,265	15.70%	\$827,614,260	14.93%	\$876,079,037	15.80%
Medium Commercial (GSP, TOU-P)	\$1,013,155,840	26.11%	\$1,365,353,378	24.63%	\$1,457,014,696	26.28%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$705,601,163	18.19%	\$729,891,706	13.16%	\$839,414,535	15.14%
Lighting (PLG, LP-13)	\$110,920,438	2.86%	\$141,017,961	2.54%	\$148,514,572	2.68%
Other (GAS)	\$5,761,527	0.15%	\$17,434,857	0.31%	\$8,323,641	0.15%
Total Utility	\$3,879,711,874	100 %	\$5,544,575,397	100 %	\$5,544,492,343	100 %

Table 13, Table 14, and Table 15 below show the increase in cost to each customer class from the cost allocation from LUMA's COSS and revenue allocation at LUMA's proposed rates relative to the revenue allocation at present rates. The revenue allocation increase in these tables relates directly to LUMA's proposed revenue allocation principles. For example, LUMA allocates less revenue to residential customers than the COSS implies in order to avoid rate shock and to maintain an ongoing embedded discount for residential customers.

¹²¹ LUMA Ex. 20.0, p.17, ll.335-337.

¹²² PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2028-AUGUST 13 2025
FINAL REV

¹²³ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2028-AUGUST 13 2025
FINAL REV

Table 13: FY2026 cost allocation from COSS and revenue allocation at proposed rates compared to revenue allocation at present rates.

Customer Class	Revenue at Present Rates ¹²⁴	COSS Increase ¹²⁵		Proposed Revenue Increase ¹²⁶	
	\$	\$	%	\$	%
Residential (GRS)	\$1,355,950,810	\$773,497,045	57.04%	\$585,083,826	43.15%
Low-Income Residential (LRS, RH3, RFR)	\$181,179,599	\$100,113,987	55.26%	\$33,556,665	18.52%
Small Commercial (GSS, USSL, CATV)	\$586,144,779	\$169,788,778	28.97%	\$214,261,418	36.55%
Medium Commercial (GSP, TOU-P)	\$991,260,218	\$313,892,057	31.67%	\$415,458,632	41.91%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$705,668,099	\$47,942,031	6.79%	\$142,772,478	20.23%
Lighting (PLG, LP-13)	\$110,253,311	\$18,499,346	16.78%	\$39,572,984	35.89%
Other (GAS)	\$5,534,023	\$9,339,328	168.76%	\$2,181,323	39.42%
Total Utility	\$3,935,990,840	\$1,433,072,573	36.40%	\$1,432,887,326 ¹²⁷	36.40%

Table 14: FY2027 cost allocation from COSS and revenue allocation at proposed rates compared to revenue allocation at present rates.

Customer Class	Revenue at Present Rates ¹²⁸	COSS Increase ¹²⁹		Proposed Revenue Increase ¹³⁰	
	\$	\$	%	\$	%
Residential (GRS)	\$1,310,798,420	\$876,846,388	66.89%	\$650,382,922	49.62%

¹²⁴ LUMA Ex. 20.0, p.18-19, ll.357-359.

¹²⁵ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2026-AUGUST 13 2025 FINAL REV, ll.50 (#1)

¹²⁶ LUMA Ex. 20.0, p.18-19, ll.357-359. Mr. Shannon noted in PC-of-LUMA-REV_ALL-1 that there was a typo in the total utility proposed revenue increase value. This table reflects the updated number that Mr. Shannon provided.

¹²⁷ PC-of-LUMA-REV_ALL-2.

¹²⁸ LUMA Ex. 20.0, p.18-19, ll.357-359.

¹²⁹ PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2027-AUGUST 13 2025 FINAL REV, ll.50 (#1).

¹³⁰ LUMA Ex. 20.0, p.18-19, ll.357-359. Mr. Shannon noted in PC-of-LUMA-REV_ALL-1 that there was a typo in the total utility proposed revenue increase value. This table reflects the updated number that Mr. Shannon provided.

Low-Income Residential (LRS, RH3, RFR)	\$176,304,786	\$114,136,052	64.74%	\$37,275,492	21.14%
Small Commercial (GSS, USSL, CATV)	\$598,105,293	\$217,498,757	36.36%	\$276,933,136	46.3%
Medium Commercial (GSP, TOU-P)	\$1,010,129,469	\$339,995,217	33.66%	\$489,330,776	48.44%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$704,156,170	\$57,644,032	8.19%	\$146,091,919	20.75%
Lighting (PLG, LP-13)	\$108,711,113	\$27,638,683	25.42%	\$42,107,261	38.73%
Other (GAS)	\$5,661,034	\$11,071,087	195.57%	\$2,669,484	47.16%
Total Utility	\$3,913,866,284	\$1,644,830,215	42.03%	\$1,644,790,990	42.02%

Table 15: FY2028 cost allocation from COSS and revenue allocation at proposed rates compared to revenue allocation at present rates.

Customer Class	Revenue at Present Rates ¹³¹	COSS Increase ¹³²		Proposed Revenue Increase ¹³³	
	\$	\$	%	\$	%
Residential (GRS)	\$1,264,035,486	\$911,182,552	72.09%	\$735,061,941	58.15%
Low-Income Residential (LRS, RH3, RFR)	\$171,068,154	\$116,977,042	68.38%	\$44,980,280	26.29%
Small Commercial (GSS, USSL, CATV)	\$609,169,265	\$218,444,995	35.86%	\$266,909,772	43.82%
Medium Commercial (GSP, TOU-P)	\$1,013,155,840	\$352,197,538	34.76%	\$443,858,856	43.81%
Large Commercial & Industrial (GST, TOU-T, LIS, PPBB)	\$705,601,163	\$24,290,543	3.44%	\$133,813,372	18.96%
Lighting (PLG, LP-13)	\$110,920,438	\$30,097,524	27.13%	\$37,594,134	33.89%
Other (GAS)	\$5,761,527	\$11,673,330	202.61%	\$2,562,114	44.47%
Total Utility	\$3,879,711,874	\$1,664,863,523	42.91%	\$1,664,780,469	42.91%

¹³¹ LUMA Ex. 20.0, p.18-19, ll.357-359

¹³² PC-of-LUMA-COST-ALL-9 attachment LUMA Schedule K-1-FY2028-AUGUST 13 2025 FINAL REV, ll.50 (#1)

¹³³ LUMA Ex. 20.0, p.18-19, ll.357-359. Mr. Shannon noted in PC-of-LUMA-REV_ALL-1 that there was a typo in the total utility proposed revenue increase value. This table reflects the updated number that Mr. Shannon provided.

H.Position of intervenors

In this section, I summarize the position of intervenors on topics related to cost and revenue allocation. I evaluate the position of intervenors separately in Section I.

Mr. Steve W. Chriss, Senior Director of Utility Partnerships for Walmart Inc., presented answer testimony and exhibits on behalf of Wal-Mart Puerto Rico, Inc. ("Walmart"). His testimony included comments on LUMA's proposed classification and allocation of production costs and LUMA's proposed revenue allocation.

Mr. E. Kyle Datta, President of New Energy Partners Inc, presented answering testimony and exhibits on behalf of the Solar & Energy Storage Association of Puerto Rico ("SESA").¹³⁴ His testimony included comments on LUMA's proposed revenue allocation to low-income customer classes.

H.1. Production cost classification

Mr. Chriss for Walmart said that "the timing and size of a utility's production plant capacity additions are generally made to meet the maximum demand."¹³⁵ He elaborated:

Basing the allocation of production plant fixed costs on the utility's system peak ensures that the resulting rates reflect cost causation and minimizes cost responsibility shifts between rate classes. Allocation of fixed production plant costs on a variable, or energy, basis can introduce shifts in cost responsibility from lower load factor classes to higher load factor classes.¹³⁶

Mr. Chriss added that the "use of an energy allocator implies that the generation plant to which that allocator is applied has no fixed cost, which is plainly not the case."¹³⁷

Based on his characterization of cost causation above, Mr. Chriss proposed classifying all production plant fixed costs to demand. He expressed concern with LUMA's proposal to classify any production plant fixed costs to energy, given the fixed nature of production plant costs.

H.2. Production cost allocation

Walmart did "not oppose the use of [LUMA]'s proposed 12CP demand allocator for demand-classified costs."¹³⁸ Mr. Chriss referenced the NARUC manual, noting that LUMA could use the 12 CP allocator if LUMA's monthly peaks "lie within a narrow range."¹³⁹ Mr. Chriss then produced an analysis that he says shows that "seven of the 12 monthly peaks are within 10 percent of the system

¹³⁵ Walmart Ex. 1.0, p.17, ll.257-259.

¹³⁶ Walmart Ex. 1.0, p.17, ll.266-277.

¹³⁷ Walmart Ex. 1.0, p.17, ll.266-277.

¹³⁸ Walmart Ex. 1.0, p.20, ll.319-321.

¹³⁹ NARUC Manual, p. 46.

peak and the remainder are within 20 percent of the system peak.” He described the monthly peak loads as “falling within the general definition of a narrow range.”¹⁴⁰

H.3. Revenue allocation

Walmart did “not oppose the Company’s proposed revenue allocation.”¹⁴¹ If the Energy Bureau approves a revenue requirement other than LUMA’s proposal, Mr. Chriss said, LUMA should “use the reduction to make some movement of classes towards cost-based rates while ensuring all classes benefit from the revenue requirement reduction.”¹⁴²

Mr. Datta for SESA expressed concern that “the ~30% cost increase for low-income customers is regressive to low-income ratepayers. It represents a significant rate increase for them, and a high energy burden.”¹⁴³

I. Evaluation of parties positions

This section presents my evaluation of the applicant and intervenor positions on cost and revenue allocation.

I.1. Cost-of-Service Study

LUMA developed billing determinants (discussed Section B of this report) to allocate costs among customer classes in their COSS. Before discussing the specifics of the functionalization, classification, and allocation choices made by LUMA in their COSS, I first consider the billing determinant allocation factors that underpin the entire analysis.

Figure 6 below illustrates the overall trend in the allocation factors (energy, demand, customer count) used in LUMA’s COSS.

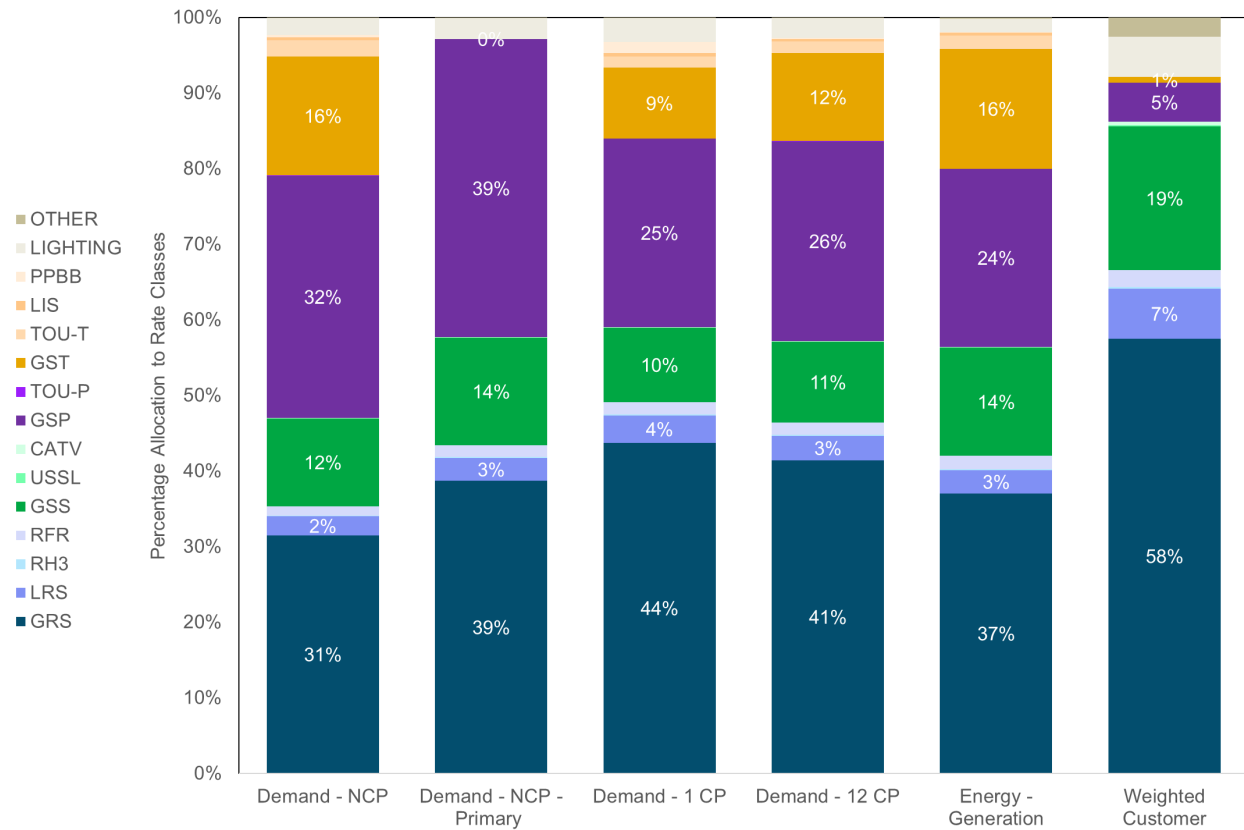
¹⁴⁰ Walmart Ex. 1.0, p.19, ll.305-308.

¹⁴¹ Walmart Ex. 1.0, p.23, ll.369-370.

¹⁴² Walmart Ex. 1.0, p.24, ll.375-377.

¹⁴³ SESA Ex. 1.0, p. 24.

Figure 6: Summary of main allocation factors by rate class.



I provide this chart to illustrate a few key points, each of which I substantiate more throughout this section.

First, the “Demand – 12 CP”, and “Energy Generation” billing determinants are relatively similar to each other (for example, GRS changes by 4%), meaning that costs assigned to each of these categories are allocated similarly. Therefore, arguments about whether LUMA should classify a cost to energy or demand have relatively little effect on the final cost allocation.

Second, for the residential class (GRS), the billing determinant LUMA uses to allocate transmission costs (“Demand – 1 CP”) and the billing determinant LUMA uses to allocate distribution costs (“Demand – NCP - Primary”) are similar (2% different), meaning that costs assigned to each of these categories are allocated similarly. This means that arguments about whether LUMA should functionalize a cost to transmission or distribution have relatively little effect on the final residential cost allocation.

Third, the billing determinant LUMA uses to allocate customer-driven costs (“Weighted Customer”) is significantly different from the other billing determinants (for example, GRS is much larger and GSP is much smaller). This means that arguments about whether LUMA should classify costs to customer or demand does significantly affect the final cost allocation.

As part of my evaluation in the next sections of this report, I tested the effect of LUMA’s functionalization, classification, and allocation assumptions on the final cost allocations to each customer class. I performed this sensitivity analysis by making changes to the FY2026 COSS Excel

model that LUMA submitted with its application.¹⁴⁴ I explain key findings in the appropriate sections below.

I.1.a. Functionalization

LUMA's choice to functionalize costs to five functions (production, transmission, distribution, customer service, and administrative and general) is aligned with accepted industry practice and reasonably segments costs by the different services that the utility provides. It is also reasonable to further sub-functionalize distribution to primary and secondary given that some customers take services from the primary distribution system only and do not utilize secondary distribution assets.

Mr. Shannon's method of splitting LUMA's O&M expenses between the transmission and distribution functions using line-miles is reasonable given the lack of available accounting data to distinguish between these functions. Mr. Shannon's assumption that transmission O&M is more expensive per line-mile and therefore should be weighted with an additional factor is also logical. Mr. Shannon did not provide any justification for the factor of 3 he applied except for his judgement.

Because LUMA did not provide supporting data for the transmission line-miles factor of 3, I tested the sensitivity of this assumption. A factor of 1 (i.e., reduction the functionalization to transmission and increasing to distribution) results in more cost allocated to small and medium C&I customers, with less cost allocated to large C&I and residential customers. This is because 1) LUMA does not allocate large C&I rate classes any distribution O&M costs so increasing distribution O&M costs has no effect and 2) residential customers have a higher coincidence factor (i.e., their peak demand drives system peak demand), which is the basis for how LUMA allocates transmission costs.

The overall effect of the transmission weighting factor on the cost allocation is small however, with a less than 1% change in cost allocation relative to LUMA's proposed COSS for most rate classes using a 1x versus 3x factor. This is because, as I explained above, LUMA's billing determinant allocators for transmission and distribution are relatively similar.

The exception is the Power Producers Connected at PREPA Bus Bar (PPBB) rate class, which sees a 32% reduction in cost allocation relative to LUMA's proposed COSS. This large change in cost allocation occurs because the PPBB rate class has very low energy usage compared to its coincident peak demand. This means that what costs LUMA allocates to coincident peak demand determine most of these customers' cost allocation. Because LUMA allocates transmission costs based on coincident peak demand, reducing transmission functionalization reduces the majority of these customers' cost allocation.

I.1.b. Classification

I.1.b.i. Production

Industry standard practice typically classifies production plant costs split between energy and demand. Standard practice typically classifies fuel costs, purchased power, and variable O&M

¹⁴⁴ I used LUMA's Schedule K-1-FY2026-AUGUST 13 2025 FINAL REV that LUMA provided in response to PC-of-LUMA-COST_ALL-9. That ROI response corrected an error in the COSS that LUMA filed on July 3, 2025.

costs as energy-related. Standard practice typically classifies the fixed costs of production plants split between energy and demand, using the common methods described next.

- **Average-and-Peak:** The utility classifies fixed costs to energy by multiplying all fixed costs by the average hourly demand (total annual energy in MWh divided by 8760 hours) divided by the system peak demand (single highest demand of the year, in MW).¹⁴⁵ The utility classifies the remainder of costs to demand. An average-and-peak classification methodology assumes that, if the utility needed to produce the same amount of energy in every hour of the year, all the utility's cost is being driven by the need to produce energy, and meeting demand does not incur any additional cost.
- **Average-and-Excess:** The utility classifies a portion of costs to demand equal to coincident peak demand divided by the sum of the coincident peak demand plus the average system demand. The utility classifies the remainder of costs to energy. An average-and-excess classification factor methodology assumes that if the utility needed to produce the same amount of energy in every hour of the year, half of the cost is associated with energy production, and the other half is associated with meeting demand.
- **Base-Peak:** In a simple base-peak method, the utility sub-functionalizes generation resources to baseload plants and peaking plants. Utilities typically differentiate between plant types based on the plant's capacity factor. The utility classifies the peaking plants to demand. The utility then splits the cost of the baseload plants between demand and energy based on average-and-peak or another method.
- **Equivalent Peaker:** For each production plant, the utility calculates the cost of a peaker plant (usually a simple-cycle combustion turbine) with the same capacity. The utility allocates the cost of the equivalent capacity peaker plant to demand. The remainder of the cost of the production plant is allocated to energy based on the assumption that all additional costs for the plant were incurred to increase the plant's operating efficiency (i.e., fuel consumed per kWh produced) and thus reduce fuel costs, relative to a peaker plant. The excess cost is therefore attributable to energy, not demand.

There are additional industry-accepted methods that combine classification and allocation into a single step, such as Probability of Dispatch. These methods require significantly more data than, given the data limitations discussed throughout LUMA's COSS, I assume LUMA does not have available. I therefore do not discuss these additional methods here.

Mr. Shannon classified production O&M costs (other than fuel and purchased power) between energy and demand using what he describes as an average-excess methodology. Instead of using average system demand in his calculation however (as described above), Mr. Shannon used the average of the monthly coincident peak demands. Monthly coincident peak demand has no relationship with energy consumption or average demand; therefore it has no relationship to system load factor. I recalculated an average-and-excess classification factor using average demand instead of monthly coincident peak demand, as discussed below.

¹⁴⁵ Average hourly demand divided by system peak demand is also called the system load factor (SLF).

Mr. Shannon classified production capital costs between demand and energy using a variation of a base-peak method. He sub-functionalized production plants to peaker and baseload plants based on the descriptions used in Genera's revenue requirement.¹⁴⁶ He then classified peaker plant costs entirely to demand and baseload plant costs entirely to energy.

Mr. Chriss, expert witness for Walmart, did not think it was appropriate to classify any production fixed costs to energy.

As described above, it is common to classify a portion of baseload plants to demand and a portion to energy because the utility incurred some of the fixed cost of baseload plants to provide energy more economically a peaker plant. Mr. Shannon's approach of classifying baseload plant costs entirely to energy is not a typical approach. The result is that Mr. Shannon classified 90% of production capital costs to energy. This is higher than if Mr. Shannon had classified a portion of baseload plants to demand.

I evaluated the data provided by LUMA on the fuel type, heat rate, and capacity factor of the peaker plants and baseload plants.¹⁴⁷ I found that both the baseload and peaker plants each had an average capacity factor of 36% in 2024. When I removed the peaker plants that did not run at all in 2024, the average capacity factor was 51%. Given the high capacity factor (i.e., energy production) of the peaker plants, I do not think it is reasonable to classify all of their costs to demand.

Using either an average-and-excess or an average-and-peak method to classify both O&M and capital production costs, is a more reasonable approach than the ones proposed by LUMA. Mr. Shannon said that there is not sufficient data available at this time to use an Equivalent Peaker method, so it is reasonable to exclude that option, as well as other options that combine classification and allocation into a single step.

Table 16 compares the average-excess classification factors used by LUMA to the average-excess and average-peak classification factors that I calculated. The table also shows the energy-demand split resulting from LUMA's proposed Base-Peak method. I discuss the effects on the final allocation of costs to rate classes after the table.

¹⁴⁶ PC-of-LUMA-COST_ALL-8.1.

¹⁴⁷ PC-of-LUMA-COST_ALL-8 Attachment 1.

Table 16: Comparison of classification factors for production costs.

	Energy	Demand	Description
LUMA's Average-Excess method for classifying production O&M	48%	52%	Demand classified: System peak demand divided by system peak plus average monthly system peak demand
LUMA's Base-Peak method for classifying production capital	90%	10%	Demand classified: peaker plants Energy classified: baseload plants
Average-Excess	37%	63%	Demand classified: system peak demand divided by system peak plus average hourly demand
Average-Peak	58%	42%	Energy classified: average hourly demand divided by system peak demand

Relative to LUMA's average-excess methodology used to classify production O&M costs, the average-and-excess ratio that I calculated decreases the amount of cost classified to energy. Conversely, the average-and-peak ratio increases the amount of cost classified to energy.

Relative to LUMA's base-peak methodology used to classify production capital costs, both average-and-excess and average-and-peak ratios decrease the amount of cost classified to energy.

To understand the effect of the choice of classification method, I applied the average-excess ratio that I calculated to O&M and capital production costs. This change had the net effect of classifying more costs to demand relative to LUMA's proposed method. The effect of the change was small, however: it resulted in less than a 5% change in cost allocation for all rate classes. This change resulted in more costs allocated to the residential and medium C&I rate class, and less costs allocated to small C&I and large C&I, since the residential and medium C&I rate classes are peakier (i.e., have a lower load factor).

The overall effect of using a different classification method is small because energy and demand allocators are relatively similar. For example, in the General Residential Service ("GRS") rate class, the energy generated to serve that rate class as a portion of total energy generated is 37%. The GRS rate class portion of the gross production coincident peak is 41%, a difference of 4%.

I.1.b.ii. Transmission

LUMA classified all transmission costs to demand. Mr. Shannon explained that "[t]he primary criteria when constructing the bulk power grid is ensuring that the grid can handle the peak load requirements."¹⁴⁸ In addition to meeting peak load, parts of the transmission system are built to deliver energy to customers that are not affected by peak demand. For example, transmission connecting baseload generation, especially when it is far from load centers, is

¹⁴⁸ LUMA Ex. 20.0, p.10, ll.173-175.

providing primarily an energy benefit. Similarly, transmission connecting remote renewables, which often have low capacity value, is providing primarily an energy benefit.

LUMA's approach of allocating all transmission costs to demand represents one bookend. To illustrate the effect of classifying some transmission cost to energy, I applied an average-and-excess methodology (discussed in the previous section) to all transmission costs, so as to split costs between demand and energy. This change resulted in more cost allocated to the C&I rate classes and less cost allocated to the residential rate classes. The residential rate classes are peakier (i.e. have a lower load factor) than the C&I rate classes, so shifting more costs to energy shifts costs away from the residential rate classes.

The overall effect is generally small, with less than 3% change in the cost allocation of each rate class. For the PPBB rate class, the effect is much larger. There is a 69% reduction in cost allocated to the PPBB rate class relative to LUMA's proposed COSS. The PPBB rate class has high demand and low energy use, so classifying costs away from demand towards energy greatly reduces the costs allocated to the PPBB rate class.

I.1.b.iii. Distribution

Utilities typically split distribution costs split between demand and customer classifications. Utilities classify a portion of distribution costs as customer-related because more customers increase a utility's distribution costs even if total energy and demand do not change. There are two common methods to split distribution costs between demand and customer, described below.

- **Minimum System Study:** The minimum system study calculates the cost of the distribution system assuming the smallest size of equipment (poles, conductors, transformers) that would ever be used by the utility. The cost of the minimum system is intended to represent the minimum distribution infrastructure required to connect customers. The more customers a utility serves, the higher the minimum system cost will be. The ratio of the minimum system cost to the cost of the actual distribution system is used as the customer-demand ratio to classify distribution costs.
- **Zero-Intercept Method:** The zero-intercept method requires plotting installed costs of distribution system equipment against the capacity ratings of that of equipment. The analyst then develops a regression between equipment cost and capacity rating; then uses the regression to identify installed cost in a theoretical no-load scenario that would solely be attributable to customers (as opposed to energy or demand). The ratio of the no-load cost to the cost of the actual distribution system is used as the customer-demand ratio to classify distribution costs.

Mr. Shannon noted that there was not sufficient cost information to use the zero-intercept method so instead conducted a minimum system study, as detailed in Section G.1 of this report.

LUMA used the minimum system study methodology to classify Material and Supplies expenses, and Vegetation Management O&M expenses, between customer and demand. LUMA classified distribution capital expenses and all other O&M costs to demand only. When asked in ROIs, Mr. Shannon explained that "[g]iven the cash-financed nature of PREPA at this time" he "chose to exclude the capital spend from the customer/demand split to avoid overclassifying customer-

related costs.”¹⁴⁹ I do not agree, however, that LUMA’s financing structure is relevant to the classification of costs. The COSS should represent cost-causation as accurately as possible and should include a portion of distribution capital costs.

To understand the effect of splitting distribution capital costs between demand and customer, I applied the customer-demand split from Mr. Shannon’s minimum system study to all distribution capital costs (including Enabling and Control Center and Buildings expenses).¹⁵⁰ Classifying more costs as customer-related allocates more cost to the residential rate classes and less cost to the C&I rate classes, because the residential rate classes have more customers.

The effect of splitting distribution capital costs between demand and customer on the cost allocated to most rate classes is less than 4% relative to LUMA’s proposed COSS. The magnitude of change in cost allocation is small because the minimum system study classifies 71% of costs to demand, so applying the minimum system study assigns only 29% of capital costs as customer-related.

For the USSL and GAS rate classes, the effect is larger. Costs allocated to USSL and GAS rate classes increase by 20% and 12% respectively. Classifying more costs as customer-related increases their allocated costs because

- the USSL rate class has very low demand per customer; and
- the GAS rate class has moderate demand per customer, but Mr. Shannon applied a weighting factor of 50 to that rate class in the weighted-customer allocator.

I.1.b.iv. Customer service

Utilities typically classify customer service as customer-related because these costs scale with the number of customers. Therefore, LUMA’s approach is reasonable.

I.1.b.v. Administrative and General (A&G) costs

There are several methods that utilities use to classify A&G expenses because A&G expenses cover a range of purposes. For example, utilities can classify property insurance to energy and demand based on production classification methods, because insurance is related to physical production facilities. Utilities can classify an employee benefit expense as labor-related because it scales with the number of employees. Mr. Shannon classified most capital and O&M A&G expenses as labor-related. In examining the A&G cost categories that Mr. Shannon has classified as labor-related, which included IT service agreements, utilities and rents, legal services, and professional and technical outsourced services, there is some correlation with labor expenses. For example, IT service agreement expenses scale with number of employees.

There are some categories that seem to have a more direct correlation with O&M or capital than labor, such as legal services or professional and technical outsourced services. LUMA does not provide information about why they classified these costs to labor. LUMA should provide more detail in its next COSS on its justifications for its classification decisions for each cost category.

¹⁴⁹ PC-of-LUMA-COST_ALL-10.

¹⁵⁰ This sensitivity aligns with the distribution capital costs that Mr. Shannon split between customer and demand when he calculated customer charges in his proposed rate design, as discussed in Section L.1.a.

I.1.c. Allocation

The allocation of costs for each function follows logically from how LUMA classifies costs. LUMA allocates energy-classified costs are allocated using an energy allocator. LUMA allocates demand-classified costs using a demand allocator. LUMA's choice of allocation factors is reasonable with a few exceptions. In the following sections, I highlight the allocation factors for which the calculation and application is more nuanced.

I.1.c.i. Production

There is a range of methods that utilities use to allocate production costs. Methods such as average-and-peak are simple because they require only basic data on average energy usage and demand during the system peak for each rate class. Other methods such as marginal-cost based methods account for the differences in production costs and reliability risk in each hour of the year.

LUMA's approach of allocating costs based on average energy and 12 CP is consistent with an average-and-excess methodology. This approach is used by many utilities. It is simple and easy to understand.

There are more sophisticated allocation methods for production costs—methods that consider factors such as differences in energy costs and reliability risk during different seasons, times of day, or hours of the year—that reflect cost-causation more accurately. Given the data limitations that LUMA discussed in its COSS, the average-and-excess method that LUMA used is reasonable.¹⁵¹ I recommend that LUMA evaluate alternative and more sophisticated methods in the future as more data becomes available.

With an average-and-excess method, the main choice the analyst makes is the choice of the allocation factor for demand-classified costs. LUMA allocated demand-classified production costs using a 12 CP allocator that considers the load of each rate class during the system peak hour of each month. Other options include a 1 CP allocator (class loads during the single highest annual peak), or other seasonal coincident peak allocators such as 3 CP (class loads during the system peak loads of the three months with highest demand).

Mr. Chriss commented on LUMA's use of a 12 CP allocator for allocating production costs. He provided analysis of the monthly peak loads then concluded that monthly peak loads fall "within the general definition of a narrow range."¹⁵²

Mr. Chriss is correct that it is reasonable to use a 12 CP allocator if the monthly peak loads fall within a narrow range. Another consideration is the maintenance requirements for generators. Scheduled maintenance typically occurs during off-peak months, resulting in constrained capacity during off-peak months despite lower system load.

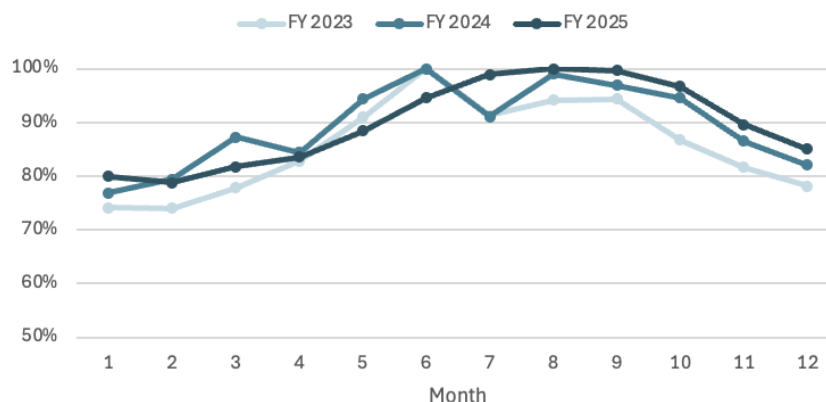
In contrast, a 1 CP or 3 CP allocator is appropriate in systems with a strong seasonal peak.

¹⁵¹ Revised Second Interim 2025 IRP Filing, Submitted in NEPR-AP-2023-0004, March 27, 2025.

¹⁵² Walmart Ex. 1.0, p.19, ll.305-308.

I also analyzed LUMA's monthly peaks from the last 3 years, using historical hourly data provided by LUMA.¹⁵³ I show a summary of peak demand in each month as a percentage of the annual system peak in Figure 7. This figure shows that demand is within 10% of system peak in May through October or November (depending on the year). Based on this analysis, an allocator that considers only 6 months of the year can also be appropriate, but a 12 CP allocator is still reasonable.

Figure 7: Monthly peak load as a percentage of annual system peak.



Mr. Shannon's method of allocating demand-classified production costs using 12 CP is a reasonable method of allocating production costs. To understand the effect of the production demand allocator, however, I tested the other bookend: a 1 CP allocator. Using a 1 CP allocator, there is less than a 0.5% change in the cost allocation of each rate class relative to LUMA's proposed COSS, because there is not a large difference in 12 CP and 1 CP for each rate class. For example, the GRS rate class has a 1 CP allocator of 44% and a 12 CP allocator of 41%. Moreover, the demand portion of production costs is only a portion of total costs that further mitigates the effect of this assumption on total cost allocations. The one exception is the PPBB rate class, where shifting to a 1 CP allocator increases its allocated costs by 8%. Given this analysis, LUMA's method of allocating demand-classified production costs is reasonable.

I.1.c.ii. Transmission

Similar to production, there is a range of methods that utilities use to allocate transmission costs. Mr. Shannon's decision to classify all transmission costs to demand, and then to allocate those costs based on 1 CP, is the simplest method. Other methods take into account the different services that the transmission system provides, and the hours of the year that drive the capacity need for specific transmission assets.

Mr. Shannon did add nuance to his transmission allocation by introducing a different allocation factor for substation costs. For these costs, he excluded large C&I customers. Mr. Shannon stated that data was not available to break out more specific details of substation costs, therefore he could not estimate which substation costs he should allocate only to distribution-connected

¹⁵³ Provided in response to PC-of-LUMA-COST_ALL-13.

customers versus all customers.¹⁵⁴ The information LUMA provided was not sufficient to evaluate whether it is reasonable assume that no substation costs are incurred to serve transmission connected (large C&I) customers.

To test the potential magnitude of the effect of allocating some substation costs to large C&I customers, I allocated substation costs using the general 1 CP allocator, which includes large C&I customers. This test showed a shift in costs towards the large C&I rate class from other rate classes. The overall effect is less than 3% change in cost allocation for most rate classes, except for the PPBB rate class. Because much of the PPBB rate class's allocated costs are transmission-related, shifting some of these costs to large C&I has an outsized percentage effect on the costs allocated to that class.

I.1.c.iii. Distribution

When allocating distribution costs, utilities commonly use non-coincident peak (NCP) for demand-classified costs and a weighted-customer allocator for customer-classified costs. More complex approaches recognize that “the peaks for substations, lines and other distribution equipment do not necessarily align with the class NCPs.”¹⁵⁵ Some allocation approaches use class energy usage in expected high-load periods for specific equipment, or NCP for a subset of the rate class that is sharing specific equipment. Coincident peak demand can also be a reasonable allocator of costs for some equipment. Without more detailed data about hourly loads on transformers, feeders and substations, and a detailed breakdown of equipment costs, these methods are not feasible.

Given the limited data available, Mr. Shannon's method of using the 12 NCP demand allocator is reasonable for this application.

In Mr. Shannon's NCP allocator for the primary system, he has not allocated any costs to large C&I customers. In Mr. Shannon's NCP allocator for the secondary system, he has not allocated any cost to medium or large C&I customers. It is an accepted practice to allocate distribution costs based on voltage level. Given the limited data available, Mr. Shannon's approach is reasonable.

I.1.c.iv. Customer service

For allocating customer-classified costs, it is best practice to use a weighted-customer allocator. Utilities typically develop customer weights based on the relative level of cost to connect customers in different rate classes. Large customers typically have more complicated installations, metering, and billing needs that cost the utility more to serve, per customer, than smaller (e.g., residential) customers.

Mr. Shannon's use of a weighted-customer allocator is reasonable because it reflects the higher cost of serving large customers and conforms with best practice.

Mr. Shannon developed the customer weightings “based on his experience and professional judgement.”¹⁵⁶ As a comparative example, Commonwealth Edison uses weighting factors that range

¹⁵⁴ PC-of-LUMA-COST-ALL-14.

¹⁵⁵ *Electric Cost Allocation for a New Era*, Regulatory Assistance Project (RAP), p. 150

¹⁵⁶ PC-of-LUMA-COST_ALL-12, part a.

from 1 for residential to 55 for large industrial companies, which is comparable to LUMA's proposal.¹⁵⁷ Commonwealth Edison's weighting factors provide one point of reference, but customer service costs could vary between LUMA and Commonwealth Edison's systems and thus cannot be used to inform LUMA's weighting factors.

Given the comparability to other jurisdictions, LUMA's proposed customer weightings are reasonable. In future COSS, LUMA should provide more justification and data to support these weightings.

I.1.c.v. Administrative and General costs

I evaluated LUMA's proposed classification and allocation of A&G costs in Section G.1.b.v of this report.

I.1.d. Overall evaluation of Cost-of-Service Study

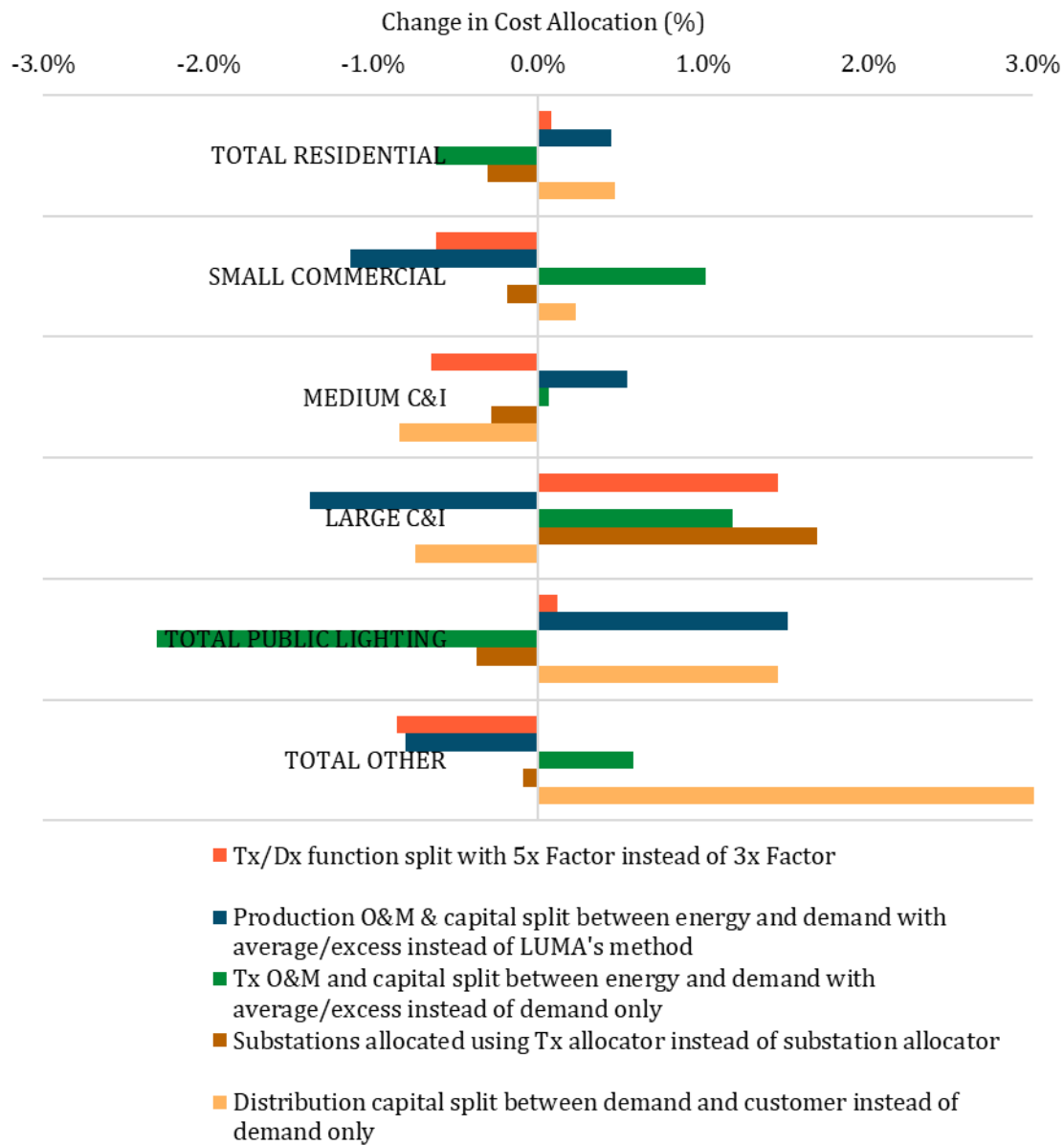
In the previous sections, I evaluated LUMA's proposed COSS methodology. I also tested the sensitivity of the cost allocation to assumptions made by LUMA. I also summarized the average effect of the sensitivity analysis on each customer class in Figure 8 below.¹⁵⁸

Figure 8 highlights that the effect of the assumptions that I tested is less than 2% on average for residential, small commercial, and medium and large C&I customer classes. As described in the previous sections, the smallest rate classes (in terms of total load and number of customers) are most affected by changes to assumptions in the COSS. These rate classes include PPBB, PLG, and GAS. Section J of this report summarizes my recommendations based on these results.

¹⁵⁷ Commonwealth Edison Company – 2024 Customer Based Allocation Factors

¹⁵⁸ The rate classes included in each customer class are shown in Table 10.

Figure 8: Summary of sensitivity of class cost allocation to COSS assumptions for FY2026.



LUMA submitted three versions of its COSS: FY2026, FY2027, and FY2028. There are two differences between these COSS versions:

- The COSS for each fiscal year uses LUMA's proposed revenue requirement for that fiscal year.
- The COSS for each fiscal year uses LUMA's forecasted energy (kWh) by rate class for that fiscal year.

LUMA's COSS did not use forecasted demand (kW) billing determinants but instead used demand billing determinants directly from recent load research data (I discussed this in more detail in Section D.4) Using *forecast* energy with *historical* demand billing determinants results in changes to load factors of each rate class between FY2026 and FY2028. These changes in load factor are an artifact of inconsistent assumptions so do not reflect expected changes of load factors of the rate classes.

Out of the three years of COSS provided, it is most reasonable to rely on the FY2026 COSS because the energy forecast used in that year is most similar to recent historical energy consumption. It is hard to draw conclusions about cost allocation results in FY2027 and FY2028 relative to FY2026, when inconsistent energy and demand billing determinants are driving some of the changes.

I.2. Revenue allocation

I.2.a. Overall revenue allocation methodology

In general, a utility's revenue allocation should be aligned with its calculated cost allocation. When a utility's proposed revenue allocation differs from cost allocation, it should be to accomplish one of two objectives: gradualism or providing an intentional subsidy for a rate class. Mr. Shannon recognized these same two policy objectives in his testimony. The challenge with evaluating LUMA's proposed revenue allocation is that the subsidies that LUMA considered to determine the final revenue allocation are not explicit.

For example, LUMA's proposed revenue allocation to the GRS rate class in FY2028 is 36.06% of the total revenue requirement (see Table 12 of this report). The proposed revenue allocation to the GRS rate class is approximately 3.2 percentage points lower than the cost LUMA allocates to the GRS rate class in FY2028 based on the COSS. The difference between the COSS cost allocation and the proposed revenue allocation implies that LUMA is proposing an enduring discount to the residential rate class.¹⁵⁹ Mr. Shannon did not explicitly identify as an initial objective a percentage or other defined discount to the GRS rate class.

This example highlights a key shortcoming of LUMA's proposed revenue allocation. There are either subsidies or other assumptions LUMA includes in its final proposed revenue allocation.

I.2.b. Revenue allocation for low-income rate classes

LUMA has the ability to propose revenue allocations for low-income rate classes whose discounts are not set by statute (LRS and RH3).¹⁶⁰ For these classes, LUMA's proposed methodology to develop low-income discounts in this proceeding is different than the existing methodology. In existing rates, LUMA provides low-income rate classes with an explicit discount relative to the GRS

¹⁵⁹ The increase in the present revenue allocation to Mr. Shannon's proposed FY2028 revenue allocation is 58.15%. This increase is lower than the upper limit that Mr. Shannon identified in his third principle for the revenue allocation, i.e., that "no class should receive an increase greater than two times the overall utility percentage increase."

¹⁶⁰ RFR rates are set by statute, so I do not consider them in my evaluation.

rate class, with the cost of the discount recovered from all customers through a rider. LUMA's new proposal calculates a separate cost and revenue allocation for each low-income rate class.

Mr. Shannon proposed first calculating the cost allocation for each low-income rate class. I reviewed the COSS and found that the COSS-informed volumetric rate for low-income rate classes and the GRS rate class are similar, so considering these rate classes separately does not have a large effect on the COSS results. Mr. Shannon then proposed calculating a separate revenue allocation for the low-income customer classes, in order to apply a subsidy to the class. LUMA's proposal limited the increase in revenue allocation of low-income rate classes to 30% relative to existing revenue.

Mr. Shannon said that if the proposed methodology for calculating low-income rates is approved, there will no longer be an explicit discount calculated for low-income customers since it would be embedded within the revenue allocation.¹⁶¹ This is challenging on two fronts:

- It disconnects the low-income rates from GRS rates. Under this method, a future proposed revenue allocation could result in rates for low-income customers that are 5% lower than GRS customers or 95% lower than GRS customers. In contrast, the income of customers in the low-income rate classes relative to other residential customers is quantifiable. It is therefore logical to define a low-income discount relative to rates for other residential customers.
- Without an explicit low-income discount, the Energy Bureau cannot specify how the low-income discount should be collected from other customers. For example, LUMA has proposed to collect the CILT and SUBA amounts through a fixed monthly charge. With LUMA's proposed change to low-income revenue allocation, the low-income discount would no longer be collected through the SUBA-HH subsidy as it currently is. LUMA's proposed change removes the ability of the Energy Bureau to make the policy decision that customers should contribute to low-income discount regardless of usage.

In Table 17 below, I have summarized equivalent volumetric rates for LUMA's existing and proposed rates (for FY2026 and FY2028) for all residential rate classes. I calculated equivalent volumetric rates as the total revenue collected from each rate class (in \$) divided by the total consumption of that rate class (in kWh). This calculation allows me to compare costs across rate classes with different rate designs. Table 17 shows that, in LUMA's proposal, LRS and RH3 rate classes receive a 23% to 25% discount, on an average volumetric basis, relative to the GRS rate class.

¹⁶¹ PC-of-LUMA-RATE_DES-7, part c.

Table 17: Summary of equivalent volumetric rates (including riders) for residential customer classes with discount of low-income rates relative to GRS

	EXISTING		PROPOSED, FY2026		PROPOSED, FY2028	
	Equivalent Volumetric Rate (\$/kWh)	Discount Relative to GRS	Equivalent Volumetric Rate (\$/kWh)	Discount Relative to GRS	Equivalent Volumetric Rate (\$/kWh)	Discount Relative to GRS
GRS	\$0.23		\$0.33		\$0.39	
LRS	\$0.21	10%	\$0.26	23%	\$0.30	23%
RH3	\$0.20	15%	\$0.25	24%	\$0.29	25%

J. Recommendations on cost and revenue allocation

J.1. Cost-of-Service Study (COSS)

In my evaluation of LUMA's COSS, I found several places where its methodology was not reasonable, represented one extreme in the range of possible methods, or lacked justification for assumptions.

When I tested the sensitivity of the class cost allocation to these methodological choices, however, there was not a significant effect on the final class cost allocation. Therefore, my assessment is that modifying the COSS methodology would have limited impact. I recommend that the Energy Bureau adopt LUMA's COSS methodology.

LUMA produced COSS studies for FY2026 through FY2028. As discussed in my overall evaluation of LUMA's COSS (Section I.1.d), LUMA used historical demand billing determinants and forecast energy billing determinants to calculate allocation factors. The billing determinants that LUMA used in its COSS for FY2027 or FY2028 are therefore not reasonable, so the Energy Bureau should not rely on these COSS to inform revenue allocation or rate design. I recommend that the Energy Bureau direct LUMA to make a filing to the Energy Bureau in advance of setting rates in FY2027 and FY2028 with its most recent estimate of forecasted energy, demand, and customer count billing determinants. Once the Energy Bureau accepts these billing determinants, LUMA should use these billing determinants and the approved revenue requirements from this proceeding to calculate rates.

J.2. Revenue allocation

LUMA's proposal to gradually implement changes to revenue allocation through FY2028 is reasonable because it is consistent with the rate design principle of stability. In FY2028, the proposed revenue allocation differs considerably from the COSS. These differences reflect subsidies to different rate classes that LUMA does not articulate well.

I recommend that the Energy Bureau direct LUMA to continue the current practice of calculating discounts for low-income rate classes relative to GRS and recovering the corresponding revenues through a rider. This practice ensures that the subsidy level provided to low-income rate classes is determined by the Energy Bureau, as opposed to being determined without justification

by LUMA. The Energy Bureau can choose to direct LUMA to increase the discount level relative to existing rates, which would be necessary to achieve rate levels for the low-income rate classes similar to LUMA's proposal.

I recommend that the Energy Bureau identify any rate classes that, in FY2028 rates, should receive enduring subsidies in their revenue allocation relative to their cost of service, and an appropriate level for the subsidies (i.e., an Energy Bureau-specified percentage reduction relative to the COSS class cost allocation). LUMA should subsequently develop FY2028 revenue allocations that reflect these subsidies relative to the COSS and then should develop a gradual path toward this revenue allocation by 2028.

Rate Design

K. Issue background

Rate design is the process by which regulators determine the prices that customers pay for electricity. Different “customer classes”—groups of customers with similar characteristics (e.g., residential, commercial, industrial)—usually have different rate designs. In determining rate designs, regulators consider these primary objectives:

- Fair recovery of costs from cost-causers.
- Provide price signals that encourage economically efficient consumption.
- Make rates understandable to customers.
- Make rates and bills predictable over time.
- Make implementation by the utility practical and cost-effective.

These objectives can conflict with one another. For example, rates that are more understandable might be less fair or less economically efficient. Regulators use judgment to balance conflicts.

Electricity rates typically include three components: energy charges, demand charges, and customer charges.

Energy charges are billed on a dollar per kilowatt hour (\$/kWh) basis. With these charges, the customer pays based on the quantity of energy consumed. Energy charges can take various forms, including:

- **Flat:** a constant price throughout the year.
- **Seasonal:** prices that vary by season or month, reflecting differences in utility costs throughout the year.
- **Time-of-use (TOU):** prices that vary by time of day, reflecting different costs of generation during the day; these charges encourage customers to shift energy consumption from high-cost to low-cost periods.
- **Inclining block:** prices that increase as the amount of usage increases, promoting conservation.
- **Declining block:** prices that decrease as usage increases, reflecting that a utility’s marginal utility costs may be lower than average utility costs.
- **Real-time or dynamic pricing:** prices that adjust frequently (e.g., hourly), reflecting market conditions (i.e., where the intersection of supply and demand sets prices), or system conditions (i.e., where the system’s cost vary throughout the day). Real-time pricing promotes fairness and efficiency but requires complex measuring equipment and market rules.

Demand charges are billed on a dollar per kilowatt basis (\$/kW). Utilities bill customers based on their instantaneous power usage at a specific point in time. Because a utility needs sufficient capacity (generation, transmission, and distribution capacity) to meet total demand continuously, a demand charge aims to allocate among customers the cost of capacity needed to meet demand. Demand charges most often apply to large industrial and commercial customers;

demand charges rarely apply to residential customers. Demand charges can take various forms. The most common are:

- **Non-coincident peak (NCP):** a demand charge applied to a customer's maximum instantaneous power demand over the billing period, regardless of when the customer's maximum usage occurs.
- **Coincident peak (CP):** a demand charge based on the customer's instantaneous power demand during the utility's system peak, generally during a pre-defined peak window.

Customer charges, are also called fixed charges, because they do not vary with a customer's consumption or demand. Utilities bill these charges to each customer on a dollar per month basis.

Regulators design rates to recover from each customer class the "class revenue requirement."¹⁶²

When rate designs include multiple components (such as energy charges, demand charges, and customer charges), the utility and regulator must decide how much revenue should be recovered by each component. In making this decision, the utility and the regulator balance various considerations. One key economic consideration is cost causation. A regulator might set the monthly fixed charge at \$15 because that is the cost driven by the number of utility customers. But a regulator might view \$15 a month as too high for some segments of the population and therefore seek to lower the charge for some while raising it for other customer classes. Raising costs for some while lowering for others ensures that the total dollars that flow from all rates produces revenue equal to the utility's revenue requirement.

Regulators implement different rate designs for different customer classes, taking into account the characteristics of each customer class. For example, regulators have historically implemented relatively simple rates for residential customers based on the rationale that residential customers have limited understanding or ability to respond to more complex rates. Regulators also consider technological feasibility: Time-of-use energy charges are not possible unless the customers have advanced meters that measure the time of energy consumption. Regulators can also use rate design to encourage economic development—for example, granting discounts to industrial customers.

L. Position of the applicant

In this section, I summarize the position of the applicant on topics related to rate design. I evaluate the position of the applicant separately in Section N.

LUMA proposed updates to rate design for fiscal years (FY) 2026 through 2028. Mr. Sam Shannon, Associate Director at Guidehouse, presented direct testimony in support of LUMA's cost-of-service study (COSS), revenue allocation, and rate design proposals. The following sections detail LUMA's proposed rate design.

¹⁶² Class revenues requirement is the share of total revenues that the regulator has allocated to that customer class in the cost allocation process.

L.1. Rate design methodology

Mr. Shannon explained that LUMA proposed rates to achieve LUMA's proposed revenue allocation. In addition, Mr. Shannon "tried to adhere to the rate design principles described by James Bonbright," including:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in:
 - a. discouraging wasteful use of service while promoting all justified types and amounts of use;
 - b. the control of the total amounts of service supplied by the company; and
9. the control of the relative uses of alternative types of service (e.g., on-peak versus off-peak electricity).¹⁶³

Mr. Shannon stated that LUMA's proposed rate design "attempts to collect a greater share of revenue from fixed and demand charges on the customer's bill. This rate design will provide some revenue stability to the utility and make it easier for the utility to withstand downward trends in consumption."¹⁶⁴

L.1.a. Customer charge

LUMA proposed updating the customer charges for all customer classes, except for the RFR¹⁶⁵ rate class, whose customer charge is defined by Puerto Rico statute.¹⁶⁶ Mr. Shannon

¹⁶³ LUMA Ex. 20.0, p.21-22, ll.405-421.

¹⁶⁴ LUMA Ex. 20.0, p.22, ll.431-432.

¹⁶⁵ RFR refers to the rate class "Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration", which applies to customers residing in a housing unit physically located within a public housing project owned by the Public Housing Administration for all domestic uses. See LUMA Tariff Book Electric Service Rates and Riders.

¹⁶⁶ LUMA Ex. 20.0, p.26, ll.517.

performed a “functionalized cost analysis” for GRS and GSS¹⁶⁷ customer classes to determine customer charges for those classes.¹⁶⁸ He “did not prepare a functionalized cost analysis for the other customer classes”, explaining that “[t]he other rate classes have demand charges which limit the importance of customer charges to these customers and to the utility.”¹⁶⁹

LUMA’s functionalized cost analysis classified several cost categories as customer-related, then allocated those customer-classified costs among customer classes. The costs that LUMA classified as customer-related for the functionalized cost analysis differ from the costs that LUMA classified as customer-related in its COSS.

¹⁶⁷ GRS refers to the rate class “General Residential Service”, which applies to all residential customers for domestic uses. GSS refers to the rate class “General Service at Secondary Distribution Voltage”, which applies to any non-residential service with a load lower than 50 kVA and temporary electric power service for limited use in streets, carnivals, and others. Definition see LUMA Tariff Book Electric Service Rates and Riders

¹⁶⁸ LUMA Ex. 20.0, p.24-25, ll.488-492.

¹⁶⁹ PC-of-LUMA-RATE_DES-9, part g.

Table 18: Summary of costs that LUMA classified as customer-related within its functional cost study.

Costs	Allocator	Amount Classified to Customer
Distribution		
Materials and Supplies and Vegetation Management O&M expenses	Weighted-Customer	Minimum system study split
Control Center and Buildings capital expenses	Energy – Generation	Minimum system study split
Enabling capital expenses	Demand – NCP	Minimum system study split
All other distribution capital expenses	Demand – NCP, Primary and Secondary	Minimum system study split
Customer Service		
Excess Expenditures O&M expense	Energy	All
Bad Debt O&M expense	Total Revenue	% of total Electric O&M classified as customer-related within functional cost study
All customer service O&M expenses (except expenses in previous 2 rows)	Weighted-Customer	All
All customer service capital expenses	Weighted-Customer	All
Administrative and General (A&G) Costs		
All A&G O&M expenses	Allocated as per COSS (see Table 9)	% of total Electric O&M classified as customer-related within functional cost study

Table 19 shows the customer classified costs resulting from LUMA's functionalized cost analysis.¹⁷⁰

¹⁷⁰ Reproduced from LUMA Ex. 20.0, p.25, Table 7.

Table 19: Customer classified costs for GRS and GSS customer classes.

Customer Class	FY2026	FY2027	FY2028
GRS	\$15.54/month	\$21.71/month	\$21.72/month
GSS	\$55.24/month	\$78.96/month	\$77.33/month

LUMA proposed increasing the fixed charge gradually over the next three years, reaching \$20/month for the GRS rate class and \$75/month for the GSS rate class in FY2028 to align roughly with what LUMA identified as customer-classified costs.¹⁷¹

LUMA proposed maintaining “a similar ratio to the status quo of customer charge rates between the GRS customers and the LRS/RH3¹⁷² customers resulting in lower customer charges [than GRS] for these low-income rates.”¹⁷³

L.1.b. Demand and energy charges

LUMA proposed demand and energy charges that result in total revenue collection from each customer class equal to LUMA’s proposed revenue allocation. Within the wide range of possible rate designs that could achieve LUMA’s proposed revenue allocation, Mr. Shannon provided little detail regarding how he determined the proposed rate designs.

Regarding demand charges, Mr. Shannon explained that “[t]he proposed demand charges are not calculated. Demand rates present an additional consideration in ratemaking in that bill impacts will vary with a customer’s load factor. My rate design attempts to balance the potential bill impacts among low and high load factor customers.”¹⁷⁴

Regarding tiered energy rates, Mr. Shannon also clarified that “The tiered rates are not based on any fixed ratio or other calculations. The rates for each tariff must generate sufficient revenue to meet the revenue requirement and still send a price signal to encourage energy conservation. Given the proposed increase to the customer charges, the tier 1 energy charges have less impact on the overall bill increases for customers.”¹⁷⁵

Mr. Shannon suggested that the “interim years after this rate case will be a good time to investigate future TOU rates.” He elaborated that “this will better align new TOU rates with the

¹⁷¹ LUMA Ex. 20.0, p.25, ll.494-495.

¹⁷² LRS refers to the rate class “Lifeline Residential Service”, which applies to residential customers who fulfill the Nutritional Assistance Program Criteria, for all domestic uses. RH3 refers to the rate class “Residential Service for Public Housing Projects”, which applies to residential customers of Public Housing Projects supported or subsidized in whole or in part by loans, grants, contributions or appropriations of the federal, state, and municipal governments. LUMA Tariff Book Electric Service Rates and Riders

¹⁷² LUMA Ex. 20.0, p.24-25, ll.488-492.

¹⁷³ LUMA Ex. 20.0, p.26, l.518-520.

¹⁷⁴ PC-of-LUMA-RATE_DES-9, part h.

¹⁷⁵ PC-of-LUMA-RATE_DES-9, part i.

timing of the upgraded billing system, the AMI meter roll-out, and the activation of the new meter data management system.”¹⁷⁶

L.1.c. Design of rate riders

LUMA also proposed changes in the rate design of the rate riders.

LUMA proposed that “the CILT and SUBA riders recover the total amount for each tariff rate via a fixed monthly charge”¹⁷⁷ and “[t]he total amount of the discounts would be allocated to customer classes via gross energy consumption.” Then, “the rates would be set by dividing each customer class’s share of the costs by the number of customers in the class.”¹⁷⁸ LUMA proposed that these changes take effect for the 2027 fiscal year, starting with the compliance filing due in May 2026.¹⁷⁹ LUMA filed proposed tariff sheets only for FY2026; those sheets do not reflect the proposed change to the CILT and SUBA rate design that would take effect in FY2027.¹⁸⁰

Mr. Shannon also explained that LUMA proposed language changes for the Net Metering Rider “to make its operation clearer to customers.” LUMA’s proposed changes “specifically identify which riders are non-bypassable, which means that the customer cannot escape the charge through other credits.”¹⁸¹ LUMA’s changes updated the specification of credits for energy exported by Net Metering customers from “charge” to “energy charge,” such that the tariff cannot be interpreted to mean that fixed monthly charges shall also be credited to Net Metering customers.¹⁸² Mr. Shannon further clarified that “there are no proposed changes to ... charges in the Net Metering Rider.”¹⁸³

L.1.d. Rate class definitions

Mr. Shannon explained that “a customer class represents groupings of customers that take electric service in similar ways.” He specified that a tariff service offering is “not necessarily” the same as a customer class, but that it is “is easier to perform rate design and revenue allocation if the customer classes closely match the tariff services.”¹⁸⁴ Mr. Shannon noted that the General Service at Primary Distribution Voltage (“GSP”), GSP-TOU, General Service at Transmission Voltage (“GST”), and GST-TOU could potentially be combined because “they have the same service characteristic (voltage level).” Mr. Shannon then further explained that “if the Energy Bureau decides to move to mandatory time-of-use for these larger customers, that will require the base classes to merge with the TOU variants.”¹⁸⁵

¹⁷⁶ LUMA Ex. 20.0, p.23, ll.460-464.

¹⁷⁷ LUMA Ex. 20.0, p.32-33, ll.662-664.

¹⁷⁸ LUMA Ex. 20.0, p.33, ll.666-669.

¹⁷⁹ LUMA Ex. 20.0, p.33, ll.772-773.

¹⁸⁰ PC-of-LUMA-RATE_DES-7, part b.

¹⁸¹ LUMA Ex. 20.0, p.36, ll.743-747.

¹⁸² LUMA Schedule O-2, pdf page 45.

¹⁸³ PC-of-LUMA-RATE_DES-8, part b.

¹⁸⁴ LUMA Ex. 20.0, p.28, ll.573-574.

¹⁸⁵ LUMA Ex. 20.0, p.29, ll.573-576.

Mr. Shannon does not support moving net metering customers to their own rate classes because “from a system perspective, customers with their own generation appear to the utility as just another low-use customer.”¹⁸⁶

Mr. Shannon also noted that electricity exports do not warrant creation of a separate customer class because “the ability of a customer to export power does not change responsibility of costs related to their consumption of power.”¹⁸⁷

L.2. Proposed rates

LUMA’s proposed base rates (without riders) are summarized in Table 20, Table 21, and Table 22 below for fiscal years 2026 through 2028. I created these tables based on LUMA’s filed Schedule M-1. I added and calculated the “% Change” column. For brevity, these tables only show rate classes with revenue allocation of greater than 10% of the total system and also include all residential rate classes. Only “1 Room Housing” rates are shown for the RFR rate class. LUMA provided a complete summary of rates in Schedule M-1 of its July 3, 2025 application.

Table 20 through Table 22 summarize the change in base rates, without riders, and therefore show larger increases than the percentage change in proposed revenue allocation, including riders, shown in Table 13 through Table 15. The increase in total revenue collected from base rates (without riders) ranges from 122% in FY2026 to 148% in FY2028. The increase in total revenue collected (including riders) ranges from 36% in FY2026 to 43% in FY2028.

¹⁸⁶ LUMA Ex. 20.0, p.29, ll.585-586.

¹⁸⁷ LUMA Ex. 20.0, p.30, ll.597-598.

Table 20: Summary of present and FY2026 proposed base rates, not including riders.

Type of Service	Present Rates	Proposed Rates		% Change
GRS - General Residential Service				
Monthly Customer Charge	\$4.00	\$10.00	per month	+150%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.04944	\$0.13200	per kWh	+167%
Additional monthly consumption	\$0.05564	\$0.14750	per kWh	+165%
LRS - Lifeline Residential Service				
Monthly Customer Charge	\$3.00	\$5.00	per month	+67%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.02054	\$0.04500	per kWh	+119%
Additional monthly consumption	\$0.05564	\$0.14750	per kWh	+165%
RH3 - Residential Service for Public Housing				
Monthly Customer Charge	\$2.00	\$4.00	per month	+100%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.00694	\$0.04000	per kWh	+476%
Additional monthly consumption	\$0.05564	\$0.14750	per kWh	+165%
RFR - Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration				
1 Room Housing				
Fixed Charge	\$30.00	\$30.00	per month	0%
Energy - In Excess of 600 kWh	\$0.05564	\$0.14750	per kWh	+165%
GSS - General Service at Secondary Distribution Voltage				
Monthly Customer Charge	\$5.00	\$25.00	per month	+400%
Energy Charge	\$0.08449	\$0.16700	per kWh	+98%
GSP - General Service at Primary Distribution Voltage				
Monthly Customer Charge	\$200.00	\$500.00	per month	+150%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.04694	\$0.12500	per kWh	+166%
Additional monthly consumption	\$0.03894	\$0.10000	per kWh	+157%
Demand Charge	\$8.10	\$13.00	per kVA	+60%
Excess Demand Charge (higher than contracted load)	\$10.00	\$16.00	per kVA	+60%
GST - General Service at Transmission Voltage				
Monthly Customer Charge	\$450.00	\$2,000.00	per month	+344%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.03650	\$0.07050	per kWh	+93%
Additional monthly consumption	\$0.03250	\$0.04500	per kWh	+38%
Demand Charge	\$7.70	\$12.00	per kVA	+56%
Excess Demand Charge (higher than contracted load)	\$9.60	\$15.00	per kVA	+56%

Table 21: Summary of present and FY2027 proposed base rates, not including riders.

Type of Service	Present Rates	Proposed Rates		% Change
GRS - General Residential Service				
Monthly Customer Charge	\$4.00	\$15.00	per month	+275%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.04944	\$0.13750	per kWh	+178%
Additional monthly consumption	\$0.05564	\$0.14900	per kWh	+168%
LRS - Lifeline Residential Service				
Monthly Customer Charge	\$3.00	\$7.00	per month	+133%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.02054	\$0.05000	per kWh	+143%
Additional monthly consumption	\$0.05564	\$0.14900	per kWh	+168%
RH3 - Residential Service for Public Housing				
Monthly Customer Charge	\$2.00	\$5.00	per month	+150%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.00694	\$0.04000	per kWh	+476%
Additional monthly consumption	\$0.05564	\$0.14900	per kWh	+168%
RFR - Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration				
1 Room Housing				
Fixed Charge	\$30.00	\$30.00	per month	0%
Energy - In Excess of 600 kWh	\$0.05564	\$0.14900	per kWh	+168%
GSS - General Service at Secondary Distribution Voltage				
Monthly Customer Charge	\$5.00	\$50.00	per month	+900%
Energy Charge	\$0.08449	\$0.18000	per kWh	+113%
GSP - General Service at Primary Distribution Voltage				
Monthly Customer Charge	\$200.00	\$600.00	per month	+200%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.04694	\$0.14500	per kWh	+209%
Additional monthly consumption	\$0.03894	\$0.05500	per kWh	+41%
Demand Charge	\$8.10	\$12.00	per kVA	+48%
Excess Demand Charge (higher than contracted load)	\$10.00	\$16.00	per kVA	+60%
GST - General Service at Transmission Voltage				
Monthly Customer Charge	\$450.00	\$2,500.00	per month	+456%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.03650	\$0.07400	per kWh	+103%
Additional monthly consumption	\$0.03250	\$0.04550	per kWh	+40%
Demand Charge	\$7.70	\$11.50	per kVA	+49%
Excess Demand Charge (higher than contracted load)	\$9.60	\$15.00	per kVA	+56%

Table 22: Summary of present and FY2028 proposed base rates, not including riders.

Type of Service	Present Rates	Proposed Rates		% Change
GRS - General Residential Service				
Monthly Customer Charge	\$4.00	\$20.00	per month	+400%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.04944	\$0.14000	per kWh	+183%
Additional monthly consumption	\$0.05564	\$0.16500	per kWh	+197%
LRS - Lifeline Residential Service				
Monthly Customer Charge	\$3.00	\$8.50	per month	+183%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.02054	\$0.06000	per kWh	+192%
Additional monthly consumption	\$0.05564	\$0.16500	per kWh	+197%
RH3 - Residential Service for Public Housing				
Monthly Customer Charge	\$2.00	\$7.00	per month	+250%
Monthly Energy Charge				
First 425 kWh of monthly consumption	\$0.00694	\$0.05500	per kWh	+693%
Additional monthly consumption	\$0.05564	\$0.16500	per kWh	+197%
RFR - Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration				
1 Room Housing				
Fixed Charge	\$30.00	\$30.00	per month	0%
Energy - In Excess of 600 kWh	\$0.05564	\$0.16500	per kWh	+197%
GSS - General Service at Secondary Distribution Voltage				
Monthly Customer Charge	\$5.00	\$75.00	per month	+1400%
Energy Charge	\$0.08449	\$0.16000	per kWh	+89%
GSP - General Service at Primary Distribution Voltage				
Monthly Customer Charge	\$200.00	\$1,000.00	per month	+400%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.04694	\$0.12100	per kWh	+158%
Additional monthly consumption	\$0.03894	\$0.09500	per kWh	+144%
Demand Charge	\$8.10	\$12.10	per kVA	+49%
Excess Demand Charge (higher than contracted load)	\$10.00	\$16.00	per kVA	+60%
GST - General Service at Transmission Voltage				
Monthly Customer Charge	\$450.00	\$5,000.00	per month	+1011%
Energy Charge				
First 300 kWh per kW of maximum demand	\$0.03650	\$0.06420	per kWh	+76%
Additional monthly consumption	\$0.03250	\$0.03750	per kWh	+15%
Demand Charge	\$7.70	\$11.25	per kVA	+46%
Excess Demand Charge (higher than contracted load)	\$9.60	\$15.00	per kVA	+56%

L.3. Bill impacts of proposed rates

Table 23 provides the increase in revenue allocation of LUMA's proposed rates by rate class relative to present rates. This is the same as average per customer bill impact.

Table 23. Summary of increase in revenue allocation (with riders) by rate class relative to present rates.¹⁸⁸

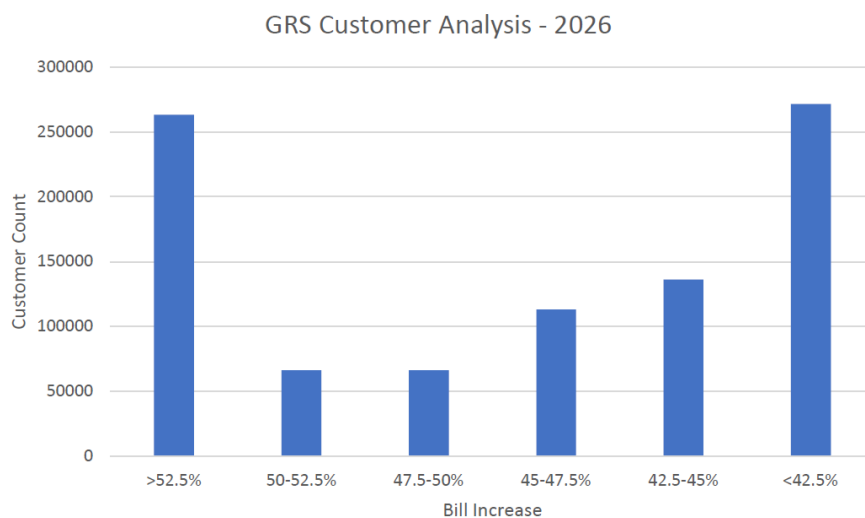
	Rate Class	FY2026	FY2027	FY2028
GRS	General Residential Service	43%	50%	58%
LRS	Lifeline Residential Service	22%	27%	34%
RH3	Residential Service for Public Housing	28%	29%	39%
RFR	Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration	14%	14%	15%
	TOTAL RESIDENTIAL	40%	46%	54%
GSS	General Service at Secondary Distribution Voltage	36%	46%	44%
USSL	Unmetered Service for Small Loads	69%	82%	138%
CATV	Cable TV Power Supplies	48%	39%	37%
	SMALL COMMERCIAL	37%	46%	44%
GSP	General Service at Primary Distribution Voltage	42%	48%	44%
TOU-P	Time of Use at Primary Distribution Voltage	39%	41%	36%
	MEDIUM C&I	42%	48%	44%
GST	General Service at Transmission Voltage	20%	21%	19%
TOU-T	Time of Use at Transmission Voltage	21%	19%	17%
LIS	Large Industrial Service	19%	20%	19%
PPBB	Power Producers Connected at PREPA Bus Bar	51%	48%	35%
	LARGE C&I	20%	21%	19%
PLG	Public Lighting General	36%	39%	34%
LP-13	Outdoor Sports Field Lighting	22%	20%	23%
	TOTAL PUBLIC LIGHTING	36%	39%	34%
GAS	General Agricultural Service and Aqueduct Pumps Operated by Rural Communities	39%	47%	44%
	TOTAL OTHER	39%	47%	44%
	TOTAL ELECTRIC RETAIL REVENUE	36%	42%	43%

¹⁸⁸ Summarized from Schedules L-1 and L-2 of LUMA's July 3, 2025 application. LUMA also provided analysis for FY2027 and FY2028.

In addition to *average* bill impacts, LUMA provided a bill frequency analysis, which showed the portion of customers with changes to bills caused by LUMA’s proposed rates for GRS, LRS, and GSS customer classes. Figure 9, Figure 10, and Figure 11 show samples of the bill frequency analysis for FY2026.¹⁸⁹ LUMA also provided an analysis of the effect of its proposed rates on customers with different usage levels for all customer classes in Schedules M-3 and M-4.

For all bill and bill impact calculations for FY2027 and FY2028, LUMA assumed that the CILT and SUBA amounts are collected through an energy charge. That assumption is inconsistent with LUMA’s proposal for CILT and SUBA to be collected through a fixed monthly charge. The proposed fixed monthly charge will not affect average bill impacts across each rate class because LUMA proposed that CILT and SUBA should continue to be allocated to rate classes based on energy. The collection of CILT and SUBA through a fixed monthly charge will affect the bill frequency analysis. In response to ROIs, Mr. Shannon stated that “LUMA will provide estimated bill impacts for the fixed charge, if approved, in May 2026 for the FY2027 rider filings.”¹⁹⁰

Figure 9: Bill impact frequency analysis (including riders) for GRS customer class for FY2026.



¹⁸⁹ Extracted from updated Schedules M6 through M9, filed August 8, 2025.

¹⁹⁰ PC-of-LUMA-RATE_DES-7, part c.

Figure 10: Bill impact frequency analysis (including riders) for LRS customer class for FY2026.

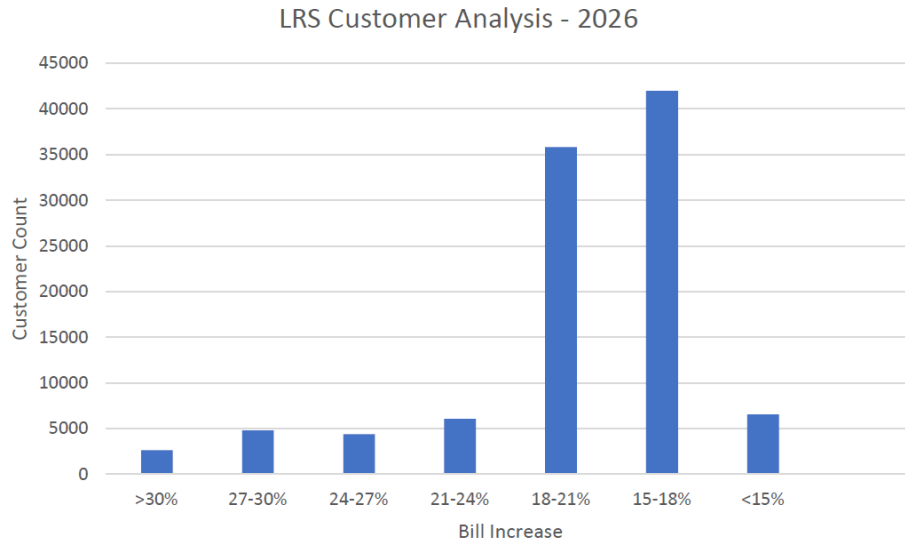
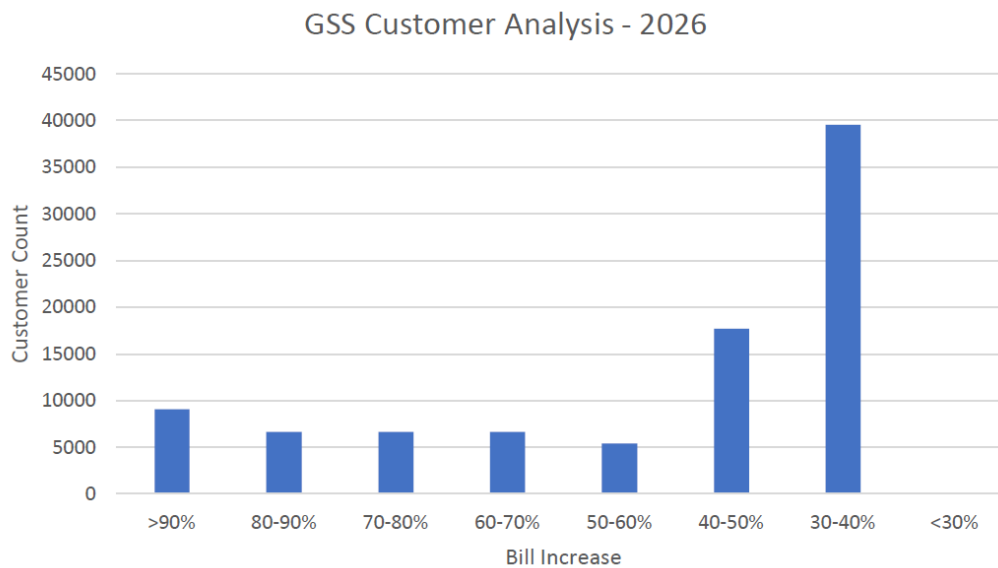


Figure 11: Bill impact frequency analysis (including riders) for GSS customer class for FY2026.



M. Position of intervenors

In this section, I summarize the position of intervenors on topics related to rate design, organized by topic. I evaluated the position of intervenors separately in Section N.

Mr. Chriss for Wal-Mart provided comments on LUMA's GST rate design, the potential to combine GSP and GST rate classes, and electric vehicle rates.

Mr. E. Kyle Datta, President of New Energy Partners Inc, presented answering testimony and exhibits on behalf of the Solar and Energy Storage Association of Puerto Rico ("SESA"), relating to LUMA's rate structure proposals on issues that Mr. Datta says "adversely impact the opportunity for customers...to invest in and benefit from customer-sited generation."¹⁹¹

Mr. Ahmad Faruqui presented answering testimony on behalf of Solar United Neighbors ("SUN") on the effect of rate design on net metering customers in Puerto Rico.¹⁹²

M.1. Rate design methodology

M.1.a. Residential rate design

Mr. Datta and Mr. Faruqui both addressed the design of residential rates, with Mr. Datta focusing only on the design of the customer charge and Mr. Faruqui addressing both the customer charge and energy charge.

M.1.a.i. Customer charge

Mr. Datta stated, "the customer classified costs appear to be significantly overstated."¹⁹³ He added:

[I]t does not seem credible that the entirety of the cost allocated to the category of customer classified costs would exist simply as Shannon states, "even if a customer uses no power, there will be some infrastructure dedicated to connecting the customer to the distribution network."¹⁹⁴

Mr. Data said that LUMA has not provided evidence that the costs classified as customer-related "vary entirely or are almost entirely based on customer count."¹⁹⁵

Mr. Datta also opposed LUMA's proposed increase to fixed charges, on these grounds:

- "LUMA's proposal violates the principle of rate gradualism."
- "High fixed charges that include costs that in reality vary with demand are inefficient and send perverse price signals that encourage inefficient use of electric service."
- "High fixed charges that include costs in reality that vary with the level of demand force low energy users, who are often low-income customers, to subsidize large users within the class."
- "High fixed charges discriminate against customers that invest in energy efficiency, NEM, behavior use reductions and other options in an effort to reduce their electric bills by increasing the share of the bill that is non-bypassable."

¹⁹¹ Faruqui Testimony, p. 2.

¹⁹² SESA Ex. 1.0, p. ii.

¹⁹³ SESA Ex. 1.0, p. 24.

¹⁹⁴ SESA Ex. 1.0, p. 26.

¹⁹⁵ SESA Ex. 1.0, p. 28.

- “High fixed charges that include costs that in reality vary with the level of demand send inefficient price signals to the utility, encouraging unnecessary spending through unjustified enhancement of revenue stability and reduction of marginal revenue effects associated with usage.”¹⁹⁶

On the topic of customer charges, Mr. Datta recommended that the Energy Bureau:

- “deny LUMA’s proposed increase in the residential fixed customer charge and more broadly the proposed rate structure changes for all customer classes;”
- “not increase the fixed charges beyond the \$4/month today for residential.”¹⁹⁷

Mr. Faruqui also did not support raising the fixed customer charge. He stated that:

The fixed charge should only be used to recover the cost of metering, billing and customer care. In some cases, it is also used to recover a portion of the cost of the power line that runs from the house to the transformer. The fixed charge cannot be used to recover all fixed costs of the utility.¹⁹⁸

Mr. Faruqui pointed to data from 171 investor-owned utilities across the U.S., showing a median fixed charge for residential customer of \$10.84/month. From this information, he concluded that “the proposed charge would be way out of line with the median charge.”¹⁹⁹

Mr. Faruqui also discussed that the proposed fixed charge would not reflect the principle of gradualism and would raise bills for low consumers of electricity. Those consumers “tend to be people living by themselves in apartments or couples living in small or energy efficient homes,” as well as “people who have installed solar panels.”²⁰⁰

M.1.a.ii. Energy charge

Mr. Faruqui proposed modifying the design of the inclining block rate for residential customers by

- widening the spread in tiers and possibly introducing a third tier, and
- applying the tiered rate structure to the entire rate (including riders, which are currently not included in the tiered rate structure).

Mr. Faruqui also asserted that “[a] much better rate design than the existing tariff is a time-of-use (TOU) rate which reflects variation in cost across the hours of the day, and across the seasons of the year.”²⁰¹

¹⁹⁶ SESA Ex. 1.0, p. 28.

¹⁹⁷ SESA Ex. 1.0, p.43.

¹⁹⁸ Faruqui Testimony, p. 12.

¹⁹⁹ Faruqui Testimony, p. 12.

²⁰⁰ Faruqui Testimony, p. 13.

²⁰¹ Faruqui Testimony, p. 14.

M.1.b. GST rate design

Mr. Chriss addressed LUMA's proposed changes to the design of the GST rate. He highlighted that for this rate class, LUMA currently applies what he calls an "hours-use" structure for the energy charge. He asserted that the energy charge is:

- a \$/kWh energy charge applied to the first 300 kWh per kW of maximum measured demand for the billing month; and
- a reduced \$/kWh energy charge applied to each additional kWh.²⁰²

He added:

The hours-use structure is not the simplest manner as it requires the analyst to have more than a surface level understanding of the rate structure in order to understand the interplay of the energy rates and load factor, as well as which demand readings to use for the calculation.²⁰³

Mr. Chriss further argued that this rate structure does not incentivize the efficient use of energy:

The structure does incentivize higher monthly load factor... This can be achieved by either decreasing demand while holding energy steady, or increasing energy while holding demand steady; however, the structure is agnostic to when the additional energy is used – a customer could increase their load factor through additional usage during system peak hours.²⁰⁴

He said that Walmart "does not oppose continuation of the current GST rate structure"²⁰⁵ but noted that if advanced meter infrastructure is deployed by LUMA and customers have access to their interval data, the Energy Bureau should require LUMA to file one or more alternative rate designs. Walmart also "does not oppose the Company's proposed charges for GST"²⁰⁶ but if a lower revenue requirement is approved by the Energy Bureau, Walmart recommended "reducing the charges on an equal percentage basis equivalent to the percent reduction in revenue requirement."²⁰⁷

M.1.c. Design of rate riders

Walmart "does not oppose the Company's proposed CILT and SUBA rate design changes for the GSP and GST rate structures."²⁰⁸

²⁰² Walmart Ex. 1.0, p.24, ll.407-412.

²⁰³ Walmart Ex. 1.0, p.27, ll.425-428.

²⁰⁴ Walmart Ex. 1.0, p.27-28, ll.442-447.

²⁰⁵ Walmart Ex. 1.0, p.28, ll.460-461.

²⁰⁶ Walmart Ex. 1.0, p.30, ll.488.

²⁰⁷ Walmart Ex. 1.0, p.30, ll.490-492.

²⁰⁸ Walmart Ex. 1.0, p.31, ll.544-545.

M.1.d. Rate class definitions

Mr. Chriss expressed concern with LUMA's suggestion that it would be reasonable to combine GSP and GST rate classes. He noted that "primary and transmission rate schedules have distinctly different service characteristics and cost allocated to them."²⁰⁹ He concluded that the Energy Bureau should have LUMA clarify that they are not combining customer classes at this time.

M.1.e. Rate for public Direct Current Fast Charging for electric vehicles

Mr. Chriss pointed out that LUMA does not currently offer any rates specifically for public Direct Current Fast Charging (DCFC) EV charging, nor is LUMA proposing to offer such a rate for FY2026 through FY2028. Mr. Chriss explained that building out a public DCFC network requires supportive rate structures and that EV-specific rate options are an important enabler for third-party investment in public EV chargers.

Walmart therefore recommended that the Bureau require LUMA to work with interested stakeholders to develop "a new EV rate specifically for public-facing DCFC EV chargers as part of its EV Implementation Support plan for F2026-2028."²¹⁰

M.2. Net Metering customer impacts

The following sections discuss issues specifically relating to Net Metering (NM) customers. Intervenors also refer to these customers as Net Energy Metering (NEM) customers.

M.2.a. Rate design impacts on Net Metering customers

Mr. Datta expressed concern that LUMA's proposed rate structure will "adversely affect existing NEM customers due to a reduction in revenues, and will slow the adoption rate of new NEM customers due to longer payback periods, ceteris paribus based on the existing revenue requirements."²¹¹

Mr. Datta stated that "LUMA's proposed restructure increases the payback period from 8 to 9 years and lowers the internal rate of return by 1%. This would lower the adoption rate of NEM, particularly when combined with federal policy changes and PV tariffs." Mr. Datta's calculated the 9-year payback period assuming a reduction in volumetric charges of 2 cents/kWh relative to current volumetric rates.²¹² His calculation of the volumetric rate reduction was based on a \$29/month fixed charge with the current revenue requirement.²¹³ Mr. Datta did not use LUMA's proposed volumetric rates.

²⁰⁹ Walmart Ex. 1.0, p.32, ll.509-510.

²¹⁰ Walmart Ex. 1.0, p.39, ll.667-669.

²¹¹ SESA Ex. 1.0, p. 24.

²¹² SESA Ex. 1.0, p. 30.

²¹³ SESA Ex. 1.0, p. 25. \$29/month includes LUMA's proposed FY2028 customer charge plus the current CILT and SUBA riders collected on a fixed monthly basis.

Mr. Faruqui presented his views on “what will happen if NEM ends in Puerto Rico.” He stated that:

- “If it is applied retroactively to existing solar customers, it will represent a violation of an existing contract.”
- If applied to new customers, it will cause a “dramatic reduction in the number of households who install solar.”²¹⁴

Mr. Faruqui also provided his views on the reforms implemented on the NEM rate for the investor-owned utilities (IOUs) in California (called the Net Billing Tariff or NBT).

M.2.b. Value of Net Energy Metering

Mr. Datta highlighted that “NEM customers have installed more than 1,200 MW of new PV capacity, and a staggering 2,486 MWh of Battery Energy Storage Systems (“BESS”)” and that “167,986 NEM customers and their suppliers have invested over \$4.6 billion in the current NEM system.”²¹⁵

Mr. Datta explained his view that NEM customers with BESS provide significant resource adequacy value to the electric system. Mr. Datta elaborated that:

Customer Battery Energy Sharing (“CBES”) initiative enables LUMA to leverage customer sited battery energy storage. Currently, 67,304 NEM customers have opted to participate in the Virtual Power Plant program which now has 402.4 MW/1 GWh of BESS in its VPP fleet. The VPP program is on track to call on its customers over 40-50 times per year, and as of July 2025, average capacity response was 40.5 MW of system peak reduction.²¹⁶

Mr. Datta attempted to estimate the resource adequacy benefit of NEM systems, using analysis from LUMA’s Resource Adequacy Study.²¹⁷ Mr. Datta applies the effective load carrying capability (ELCC) of 4-hour standalone storage to the BESS under CBES, using 90% ELCC for all existing CBES and 80% ELCC for future CBES.²¹⁸ Mr. Datta concluded that “NEM-CBES current peak power contribution is saving ~18 hours of loss of load hours (“LOLH”) and the projected increase in NEM could save an additional 16 hours of LOLH island wide.”

Mr. Datta stated that “[u]sing the PREB VoLL, a territory wide outage for one peak hour costs all ratepayer \$142 MM.”²¹⁹ Based on the VoLL, Mr. Datta estimated that the savings from NEM-CBES is between \$2 billion per year (with existing NEM CBES) to \$4.7 billion per year (with

²¹⁴ Faruqui Testimony, p. 4.

²¹⁵ SESA Ex. 1.0, p. ii.

²¹⁶ SESA Ex. 1.0, p. 14.

²¹⁷ Puerto Rico Electric System Resource Adequacy Analysis Report October 21, 2024. Submitted by LUMA.

²¹⁸ SESA Ex. 1.0, p. 18.

²¹⁹ SESA Ex. 1.0, p. 19.

forecasted NEM adoption) and that “these [savings] grossly exceed any costs NEM imposes on the system.”²²⁰

Mr. Datta also explained that VPP aggregators currently receive \$1.25/kWh, “which is largely passed on to customer.” He added that “[t]here are ~50 VPP events per year or approximately \$11.8MM of payments in any given year.”²²¹ Mr. Datta estimated that customer receiving only VPP incentive payments would have a 30-year payback period for the solar and storage systems.²²²

Mr. Datta also estimated a Renewable Portfolio Standard (RPS) value of NEM exports.²²³

Mr. Datta suggested that “PREB should direct LUMA to develop a comprehensive benefit-cost analysis of customer-sited DG for use in evaluating and setting just compensation and rates for all DG customers, including NEM, after this rate case and before the VoS study commences.”²²⁴

N. Evaluation of parties positions

This section presents my evaluation of the applicant and intervenor positions on rate design. For residential and C&I rate classes, I evaluated both rate design methodology and bill impacts. My evaluation considers these primary objectives:

- Fair recovery of costs from cost-causers.
- Provide price signals that encourage economically efficient consumption.
- Make rates understandable to customers.
- Make rates and bills predictable over time.
- Make implementation by the utility practical and cost-effective.

Regulators use judgment to determine an appropriate balance among these sometimes conflicting objectives. This section of the report evaluates rate design options relative to these objectives.

If rates were designed only on the principle of fair recovery of costs from cost-causers, each component of the rate (customer charge, volumetric charge, demand charge) would recover costs that vary with the billing determinant of the charge component. This type of rate is called a cost-based rate. In a cost-based rate:

- The customer charge recovers customer-classified costs. These are costs that vary directly with the number of customers connected to the utility’s transmission and distribution system.

²²⁰ SESA Ex. 1.0, p. iii, 19, 20.

²²¹ SESA Ex. 1.0, p. 21.

²²² SESA Ex. 1.0, p. 21.

²²³ SESA Ex. 1.0, p. 22.

²²⁴ SESA Ex. 1.0, p. v. Mr. Datta states “As directed by Act 10-2024, by 2030 the PREB will perform a value of solar study.” (p. v) but later “I recognize the Value of Solar (“VoS”) study cannot occur until after 2030.” (p. 15). The statement in the summary that the VoS study will be completed by 2030 appears to be an error.

- The demand charge recovers all demand-classified costs. For rates with an NCP-based demand charge, rate analysts account for the difference between CP and NCP billing determinants, since many demand-classified costs are allocated to customer classes based on CP billing determinants.
- The volumetric charge recovers energy-classified costs.

If rates were designed only on the principle of economic efficiency, rates would align with utility marginal cost.²²⁵

Rates that provide economically efficient price signals can be different than cost-based rates. A rate that recovers long-run marginal cost through energy and demand charges with the remaining revenue requirement through the customer charge can have a customer charge that is higher or lower than a customer charge calculated based on customer-related costs alone.

In addition to considering cost-causation and economic efficiency, rates should be understandable to customers, and practical and cost effective for the utility to implement. Many utilities do not charge demand charges to residential customers, in part because they are difficult for those customers to understand. Practicality also dictates that utilities cannot charge time-of-use (TOU) rates to customers unless they have advanced metering infrastructure (AMI) and cost-effectiveness dictates that AMI roll-out should be done on a large-scale, organized basis and not ad hoc.

Finally, regulators should consider the effect of rates on customers. Regulators should consider the predictability of rates and bills over time and introducing gradual changes instead of large step-changes to customer rates and bills.

In the current Energy Bureau rate case, LUMA has proposed a 36% – 43% increase to the annual revenue requirement.²²⁶ Although the revenue requirement approved by the Energy Bureau will determine the average bill impact across all customers, the revenue allocation and rate design will determine how that increase affects average bills for each rate class and the bills for individual customers. I will analyze and evaluate the impact of LUMA’s proposed rate design on both customers with average usage and customers with a range of different usage levels.

Bill impact analysis helps to evaluate concerns regarding rate and bill stability associated with changes to rate designs. Following the principle of rate and bill stability (also referred to as the principle of gradualism), changes to rate design should avoid causing overly dramatic bill increases or decreases for customers. This objective, however, conflicts with other rate design objectives including the fair apportionment of costs, as any change to rate design, including one that improves fairness, will unavoidably lead to changes in bills for different individual customers relative to the status quo.

Beyond considering bill stability, I caution against prioritizing bill reductions for certain customer groups – for example, prioritizing bill reductions for small users at the expense of large

²²⁵ “Economic efficiency” refers to matching supply and demand at the minimum cost. I am not referring to the separate concept of “energy efficiency”, which means using less energy to perform the same task.

²²⁶ The proposed annual revenue requirement increases from FY2026 through FY2028. See summary in Table 13, Table 14, and Table 15 of this report.

users or vice versa. Absent a clear statutory directive, doing so risks violating the statutory prohibition against undue discrimination.

N.1. Residential rate design

LUMA structures its existing and proposed residential rates with a fixed monthly customer charge and an inclining-block volumetric charge. I show current and proposed rates in Table 20, Table 21, and Table 22 of this report. This section discusses the design of both the customer and volumetric components of LUMA's proposed residential rate design.

N.1.a. Customer charge methodology

LUMA's proposed rate design calculates a customer charge for GRS and GSS customer classes based on a functionalized cost analysis. The costs LUMA included as customer-related in this analysis are summarized in this report in Table 18 and evaluated below.

Mr. Datta argued that the customer-related costs identified by Mr. Shannon "appear to be significantly overstated."²²⁷ Mr. Faruqui, on behalf of SUN, agreed with this stance and proposed that "the fixed charge should only be used to recover the cost of metering, billing and customer care" and potentially "a portion of the cost of the power line that runs from the house to the transformer."²²⁸

Mr. Faruqui's proposal to include only metering, billing, and customer care costs represents only a portion of customer-driven costs. Consider a distribution system that has been built to serve 100 customers. Then consider a distribution system that has been built to serve five customers whose total load and demand is exactly equal to the total load and demand of the 100 customers. If costs were allocated to these two groups of customers based on energy and demand alone, the 100 customers and the five customers would be allocated the same cost. It is easy to see, however, that the distribution system needed to serve 100 customers is much more extensive than the distribution system needed to serve five customers. That is why it makes sense to allocate a portion of costs of the distribution system based on number of customers. A minimum system study, like the one proposed by LUMA, aims to identify the appropriate portion of distribution costs that are customer-driven.

Based on its proposed COSS, LUMA included in its proposed customer charge the customer-classified portion of the following costs:

- Distribution O&M costs of Materials and Supplies and Vegetation Management
- Customer service O&M costs
- Customer service capital costs

LUMA also included in the customer charge a portion of distribution capital costs, Bad Debt, and A&M O&M expenses. LUMA split distribution capital costs between customer and demand using a minimum system study approach, as explained in Section G.1.b.iii. Mr. Shannon did not include these costs as customer-related in LUMA's proposed COSS (see evaluation in Section I.1.b.iii), but as I explained above, it is reasonable to assume that a portion of these costs are

²²⁷ SESA Ex. 1.0, p. 24.

²²⁸ Faruqui Testimony, p. 12.

customer-related. Similarly, a portion of Bad Debt and A&G O&M expenses are incurred by LUMA to serve customers, regardless of energy or demand, therefore including these costs in the customer charge is reasonable.

There are three concerns with LUMA's functional cost study:

- When calculating the customer charge, LUMA double-counted distribution capital expenses.
- LUMA allocated some distribution costs in the functional cost analysis based on energy and demand allocation factors (see Table 18 of this report). It is more appropriate to allocate these costs based on a weighted-customer allocator because they are customer-related.
- LUMA included the total GRS-allocated Excess Expenditures cost in the customer charge. LUMA allocated this expense based on energy in the COSS. Mr. Shannon did not provide compelling evidence on why these costs depend on number of customers. These costs should be excluded from the customer charge.²²⁹

In order to understand the effect of these proposed changes, I recalculated the functional cost analysis with the above three changes. The results are shown in Table 24. With these changes implemented, the result is approximately \$3 lower than LUMA's calculation in FY2028.

Table 24: Customer-related costs for GRS customer class with cumulative effect of suggested changes to functional cost analysis.

GRS	FY2026	FY2028
LUMA's Proposal	\$15.54/month	\$21.72/month
+ Distribution Capital Error Corrected	\$14.38/month	\$19.02/month
+ Costs Allocated with Weighted-Customer Allocator	\$15.02/month	\$19.79/month
+ Excess Expenditures costs removed	\$14.22/month	\$18.79/month

Mr. Faruqui's comparison of LUMA's proposed \$20/month fixed charge to the median fixed charge of \$10.84/month for investor-owned utilities across the U.S. is misplaced. LUMA's total proposed residential electricity rate of \$0.33/kWh (see Table 17) is approximately double the U.S. average residential rate of \$0.17/kWh.²³⁰ It is therefore reasonable that the fixed charge component would also be roughly double.

Mr. Datta provided his view that "[h]igh fixed charges that include costs that in reality vary with demand are inefficient and send perverse price signals that encourage inefficient use of electric service."²³¹ Mr. Datta's statement over-simplifies the challenge of designing efficient rates. Recovering demand-related costs via an energy charge (as Mr. Datta proposes since there is no demand charge for residential customers) is also not economically efficient because it increases the

²²⁹ In PC-of-LUMA-RATE_DEC-5, Mr. Shannon explained that explained that "The Excess Expenditure revenue requirement item does not fit neatly into traditional cost functionalization and classification. Therefore, Mr. Shannon used his judgement to assign those costs to the customer functional cost area."

²³⁰ https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

²³¹ SESA Ex. 1.0, p. 28.

volumetric energy charge above energy marginal cost. Nevertheless, LUMA’s proposed customer charge does not include demand-driven costs as LUMA calculates it using customer-driven costs through a functionalized cost analysis.

In summary, LUMA’s methodology for calculating the GRS customer charge is reasonable, except for the three issues that I identified above. After correcting the issues with LUMA’s functional cost analysis, the customer-related costs in FY2028 are \$18.79/month. Nevertheless, because LUMA did not include demand-related costs in the customer charge, the \$20/month customer charge that LUMA proposed in FY2028 is reasonable.

LUMA proposed maintaining “a similar ratio to the status quo of customer charge rates between the GRS customers and the LRS/RH3²³² customers resulting in lower customer charges [than GRS] for these low-income rates.”²³³ LUMA’s proposed rates have a ratio of LRS customer charge to GRS customer charge of 43% – 50%, depending on the year, compared to 75% in present rates.²³⁴ Similarly, LUMA’s proposed rates have a lower ratio of RH3 customer charge to GRS customer charge compared to current rates. A lower customer charge for the low-income rate classes is reasonable given the intent to provide low-income customers with discounted rates.

I evaluate the bill impacts of LUMA’s proposed residential rate designs, including the increased customer charge, in Section N.1.c, prior to making overall recommendations.

N.1.b. Volumetric charge methodology

LUMA’s existing and proposed volumetric charge for residential customers is a two-tiered inclining block volumetric rate. Like all inclining block rates, it charges a lower rate up to a threshold (in LUMA’s case 425 kWh per month), and a higher rate above the threshold.

Table 25 summarizes LUMA’s existing and proposed volumetric rates. I have included a summary of the ratio of Tier 2 to Tier 1 rates, along with the difference between Tier 2 and Tier 1 rates. As Mr. Shannon explained, “the tiered rates are not based on any fixed ratio or other calculations.”²³⁵

²³² LRS refers to the rate class “Lifeline Residential Service”, which applies to residential customers who fulfill the Nutritional Assistance Program Criteria, for all domestic uses. RH3 refers to the rate class “Residential Service for Public Housing Projects”, which applies to residential customers of Public Housing Projects supported or subsidized in whole or in part by loans, grants, contributions or appropriations of the federal, state, and municipal governments. LUMA Tariff Book Electric Service Rates and Riders

²³³ LUMA Ex. 20.0, p.24-25, ll.488-492.

²³⁴ LUMA Ex. 20.0, p.26, ll.518-520.

²³⁵ Calculated from LUMA Schedule M-1.

²³⁵ PC-of-LUMA-RATE_DES-9, part i.

Table 25: LUMA's existing and proposed volumetric base rates (without riders).

Year	Tier 1 (\$/kWh) (first 425 kWh)	Tier 2 (\$/kWh) (>425 kWh)	Tier 2 / Tier 1 (%)	Tier 2 - Tier 1 (\$/kWh)
Present Rates	\$0.04944	\$0.05564	113%	\$0.006
FY2026	\$0.13200	\$0.14750	112%	\$0.016
FY2027	\$0.1375	\$0.14900	108%	\$0.012
FY2028	\$0.1400	\$0.16500	118%	\$0.025

Mr. Faruqui proposed widening the spread between tiers and possibly introducing a third tier, as well as applying the tiered rate structure to the entire rate.

To increase the efficiency of price signals, LUMA's proposal to maintain an inclining block rate while increasing the fixed charge is counterproductive. An inclining block tiered rate provides a discount (relative to no tiers) for low usage customers. This is precisely the opposite of what an increase fixed charge accomplishes. As detailed in the following paragraphs, LUMA's proposed volumetric charges are higher than long-run marginal cost. Reducing the second tier energy charge by using a flat energy charge will bring the energy charge more in line with long-run marginal cost, thereby increasing the rate's economic efficiency. Mr. Faruqui's proposal to increase the spread between tiers and apply the tiered rate structure to the entire rate (including riders) will have the opposite effect.

To understand the magnitude of long-run utility marginal costs in Puerto Rico, I estimated energy, generation capacity, and T&D capacity marginal costs.

Marginal energy costs are approximately equal to fuel and purchased power costs. Fuel and purchased power costs are collected through the FCA and PPCA riders, with a forecast rider value of \$0.15208/kWh in FY2026.

I estimate generation capacity marginal cost as \$91/kW-yr in 2027.²³⁶ T&D marginal cost estimates for the PREPA system are not available, so I used a conservative estimate of \$100/kW-yr for distribution marginal cost and \$100/kW-yr transmission marginal costs. Because the GRS rate does not have a demand charge, I converted the generation and T&D marginal capacity costs to equivalent volumetric rates. Using the GRS rate class load factor of 48%, the combined \$291/kW-yr capacity value translates to a volumetric rate of \$0.0691/kWh.

Because fuel and purchased power costs are collected through riders, \$0.0691/kWh is a conservative estimate of the marginal cost of the costs collected through LUMA's volumetric base rates. A volumetric charge above this level is higher than marginal cost and economically inefficient.

In addition, regulators have historically used inclining block rates to support affordability for low-income customers based on the premise that they were the smallest users. As I will discuss

²³⁶ Synapse Energy Economics, *Avoided Costs of Energy Efficiency Resources in Puerto Rico, 2023-2045*, issued by the PREB for application to energy efficiency planning and analysis in NEPR-MI-2021-0009, July 17, 2024. Avoided capacity cost is lower in 2026 and 2028 so I used 2027 as a conservative estimate.

in the rate and bill impacts section below, the link between customer usage and income has been shown to be small. It is much more efficient to directly provide discounts to low-income customers as Puerto Rico does.

Based on the above analysis, I recommend that the Energy Bureau consider a flat energy rate instead of an inclining block rate for the GRS customer class. Using LUMA's proposed revenue requirement, residential revenue allocation and customer charge, a flat volumetric charge would be:

- \$0.13767/kWh in FY2026
- \$0.14171/kWh in FY2027
- \$0.14915/kWh in FY2028

This flat energy charge is less than one cent per kWh higher than LUMA's proposed Tier 1 rate in FY2028. A customer who consumes the maximum Tier 1 energy (425kWh/month) and no Tier 2 energy would see the highest bill increase under my recommendation. For this maximally-affected customer, their bill would increase by \$3.89/month. All other customers would see a lower bill increase, or in many cases a bill decrease if they consume a large amount of Tier 2 energy (because the flat rate is lower than the Tier 2 rate).

Mr. Faruqui suggested that, in the longer term, time-of-use (TOU) rates are a "much better rate design than the existing tariff."²³⁷ I agree with Mr. Faruqui's suggestion. Assuming a sound TOU rate design, TOU rates can provide a price signal that is better aligned with marginal costs. Mr. Shannon suggested that future TOU rates should be investigated after this rate case. In the coming months, I recommend that LUMA develop a robust plan to study and implement TOU rates in the coming years, such that TOU rates can be rolled out on a large scale as soon as possible.

N.1.c. Bill impacts of proposed rates

This section provides estimated bill impacts for customers on GRS (General Residential Service) and LRS (Lifeline Residential Service) rates. This section compares the bill impacts of two proposed rates relative to existing rates for each rate class. Both rates recover LUMA's proposed revenue requirement using LUMA's proposed revenue allocation by rate class. This approach ensures an apples-to-apples comparison of the impacts of rate design independent from changes in total revenue requirement or revenue allocation. These rates do not include riders. The two rates are:

- **Existing Fixed Charge, Proposed Revenue** – maintains the existing fixed customer charge (as proposed by Mr. Datta) and increases volumetric charges in order to recover LUMA's proposed class revenue requirement.
- **LUMA Proposed** – LUMA's proposed rates.

For GRS and LRS rate classes, this section provides the following information:

- **Table of rate designs.** This table compares existing base rates with the two proposed rate designs.

²³⁷ Faruqui Testimony, p.14.

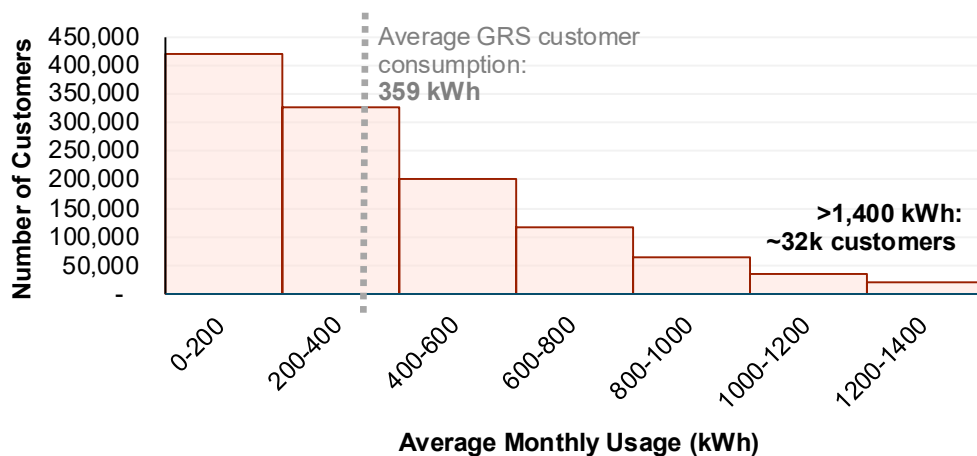
- **Histogram of number of customers by monthly usage level.** Based on data provided by LUMA, this figure shows how many customers use electricity at different monthly usage levels.
- **Existing bills by usage level.** This figure calculates monthly bills under existing rates for the middle of each usage category. For example, for the 200-400 kWh/month category, this figure shows monthly bills for a customer using 300 kWh/month. These bill impacts are calculated assuming the existing 18c/kWh total riders on top of the base rates.
- **Change in bills by usage levels and rate design.** This figure shows the change in monthly bills for each usage level under the two proposed rate designs, compared to bills under existing rates. Because the level and design of future riders are not clear, this figure assumes no change to riders.

Table 26: GRS rate designs modeled

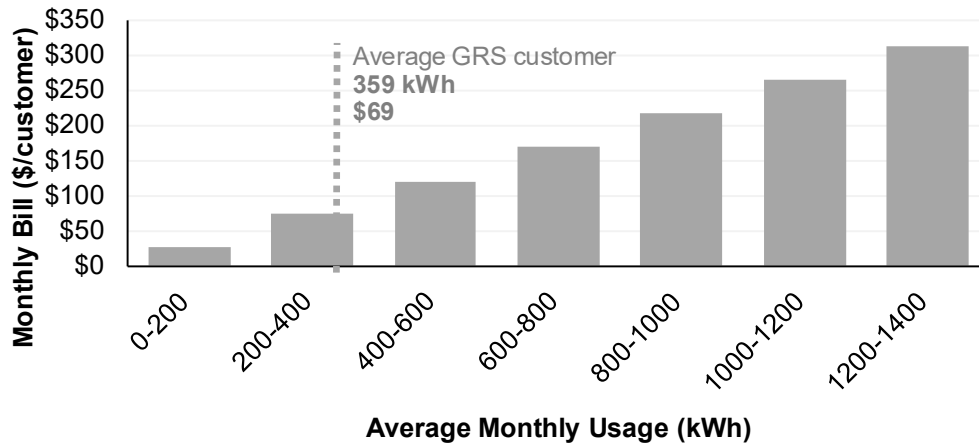
Design	Component	FY2026	FY2028
Existing	Fixed (\$/month)	\$4.00/month	\$4.00/month
	Energy, < 425 kWh (\$/kWh)	\$0.049/kWh	\$0.049/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.056/kWh	\$0.056/kWh
Existing Fixed Charge, Proposed Revenue	Fixed (\$/month)	\$4.00/month	\$4.00/month
	Energy, < 425 kWh (\$/kWh)	\$0.146/kWh	\$0.185/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.164/kWh	\$0.208/kWh
Proposed	Fixed (\$/month)	\$10.00/month	\$20.00/month
	Energy, < 425 kWh (\$/kWh)	\$0.132/kWh	\$0.140/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.148/kWh	\$0.165/kWh

Figure 12: Distribution of GRS customer usage and bill impacts

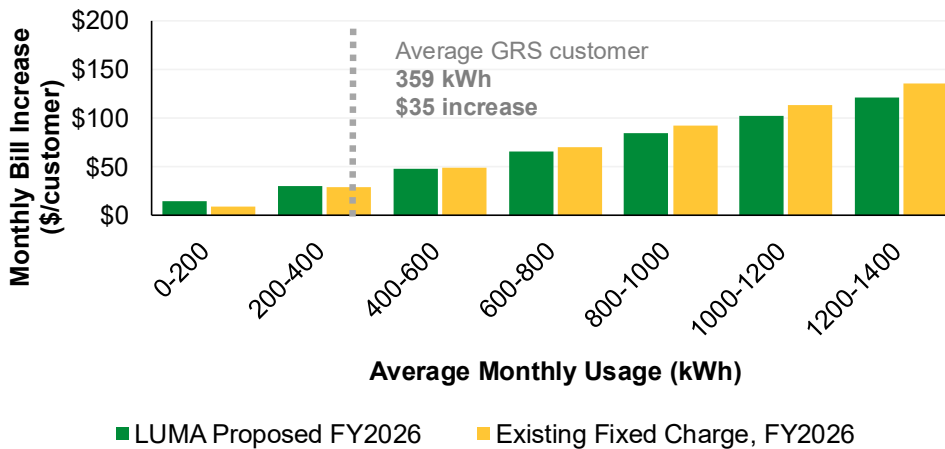
Average Monthly Consumption:



Existing Bills (including riders):



FY2026 Monthly Base Charge Increases (no change to riders):



FY2028 Monthly Base Charge Increases (no change to riders):

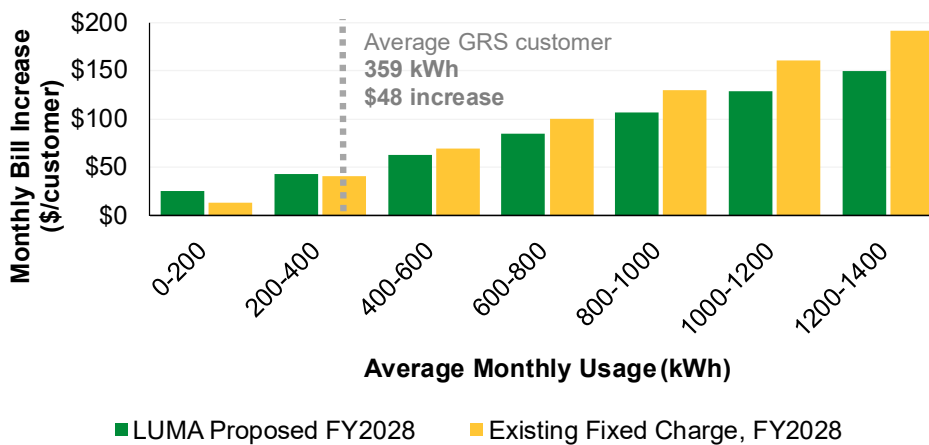
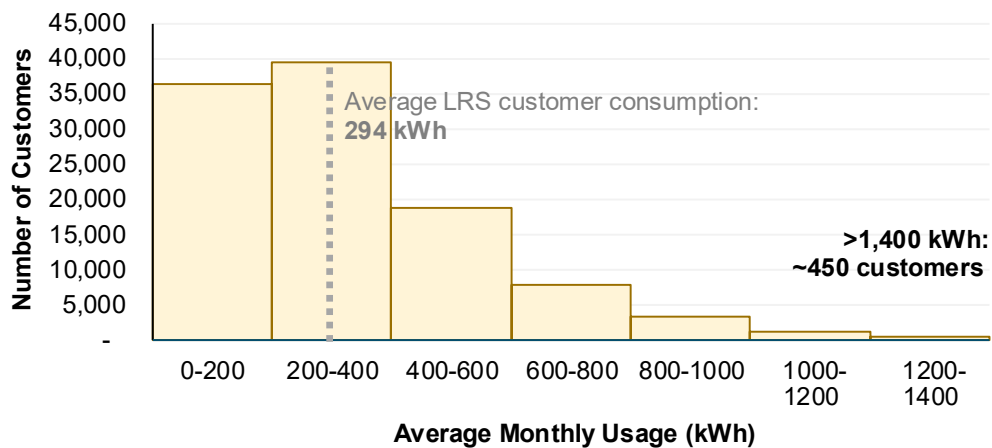


Table 27: LRS rate designs modeled

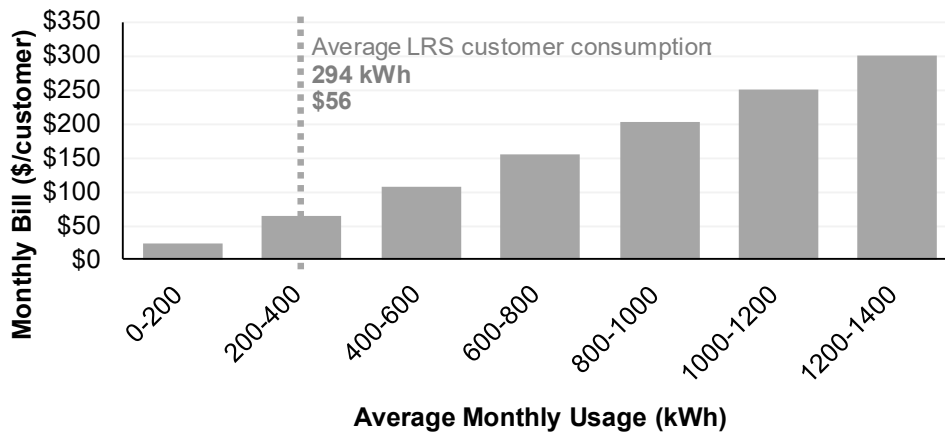
Design	Component	FY2026	FY2028
Existing	Fixed (\$/month)	\$3.00/month	\$3.00/month
	Energy, < 425 kWh (\$/kWh)	\$0.021/kWh	\$0.021/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.056/kWh	\$0.056/kWh
Existing Fixed Charge, Proposed Revenue	Fixed (\$/month)	\$3.00/month	\$3.00/month
	Energy, < 425 kWh (\$/kWh)	\$0.054/kWh	\$0.076/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.146/kWh	\$0.206/kWh
Proposed	Fixed (\$/month)	\$5.00/month	\$8.50/month
	Energy, < 425 kWh (\$/kWh)	\$0.045/kWh	\$0.060/kWh
	Energy, > 425 kWh (\$/kWh)	\$0.148/kWh	\$0.165/kWh

Figure 13: Distribution of LRS Customer Usage and Bill Impacts

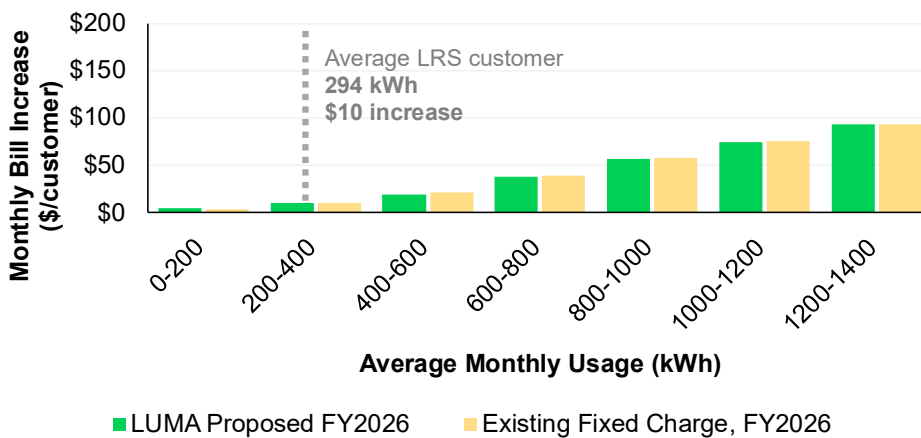
Average Monthly Consumption:



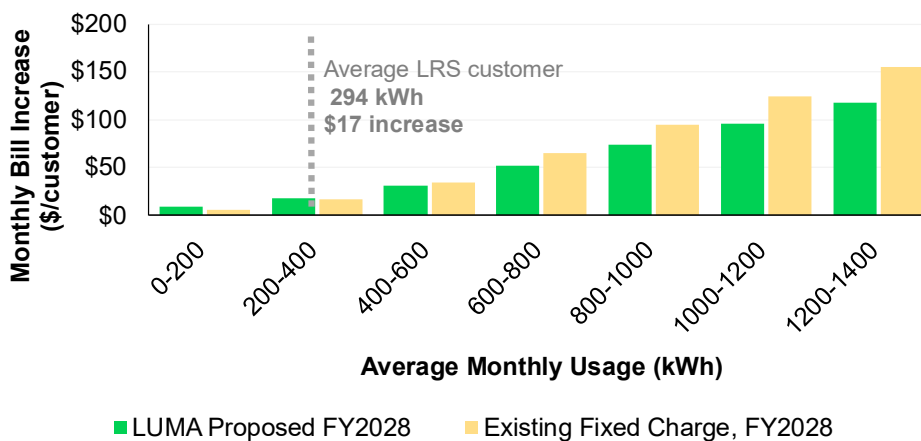
Existing Bills (including riders):



FY2026 Monthly Base Charge Increases (no change to riders):



FY2028 Monthly Base Charge Increases (no change to riders):



Mr. Datta argued that LUMA’s proposed fixed charge increase for residential customers “violates the principle of rate gradualism.” To address this concern, I compared customer bills with

LUMA's proposed rate design to customer bills with the existing fixed charge and LUMA's proposed revenues (see Figure 12 and Figure 13). I considered customers using 0-600 kWh/mo, representing 78% of GRS customers and 87% of LRS customers. I found that, for these residential customers in FY2028, the difference customer bills in between these two rates was less than \$11/month on the GRS rate, and less than \$5/month on the LRS rate. An \$11/month bill impact phased in over 3 years does not violate the principle of gradualism. Customers greater than 600 kWh/mo saw a bill decrease under LUMA's proposed design.

Mr. Datta argued that low energy users are often low-income customers but did not provide evidence to support this assertion. A recent study of residential electricity use in California found that occupancy, climate, and installed distributed generation are all more important factors in determining household electricity usage than income.²³⁸ To the extent the Bureau is considering affordability for low-income customers as a policy objective, I recommend the Bureau focus on the discounts provided through the low-income rates and the accessibility of those rates to low-income households, as opposed to focusing attention on low-usage customers within the GRS rate class, who are not necessarily low-income customers.

N.2. Commercial and industrial rate design

LUMA structures rates for commercial and industrial (C&I) customers using a combination of fixed customer charges, demand charges, and volumetric energy charges. The largest difference between C&I rates and residential rates is the presence of demand charges for C&I customers. Demand charges in C&I rates are common industry practice as C&I customers have more predictable peak demand, more understanding of demand charges, and more ability to modify their peak demand.

N.2.a. Rate design methodology

Within C&I rate design, there is a spectrum of reasonable rate designs that split cost recovery between fixed customer charges, demand charges, and volumetric energy charges.

Mr. Shannon provided few details on how he developed LUMA's proposed C&I rate designs. The main details were on the methodology for developing the customer charge for the GSS (General Service at Secondary Distribution Voltage) rate class. Mr. Shannon used the same methodology that he used to develop the customer charge for the GRS (General Residential Service) rate class. As I described in Section N.1.a, Mr. Shannon's methodology of calculating customer-related costs and recovering those costs through the customer charge is reasonable.

LUMA's GSS customer charge calculation results in an increase in customer charge from the existing rate of \$5/month in FY2025 to a rate of \$75/month in FY2028. I evaluate the bill impacts of LUMA's proposed GSS rate design, including the increased customer charge, in Section N.2.b, prior to making overall recommendations.

For all other C&I rate classes, LUMA retains the existing rate structure, in the sense that the components (customer, energy, and demand) of each rate are unchanged. But LUMA has changed

²³⁸ Borenstein, Severin. "Energy Hogs and Energy Angels: What Does Residential Electricity Usage Really Tell Us About Profligate Consumptions." NBER Working Paper 32023. January 2024. https://www.nber.org/system/files/working_papers/w32023/w32023.pdf

the rate design in the sense that the relative portion of costs that each rate component recovers has changed.

On the one hand, LUMA provided few details on its proposed rate designs for other C&I rate classes (see summary in Section L.1.a and L.1.b.). On the other hand, I find that the new proposed rates fall within a wide range of reasonable options.

Among the rate designs for LUMA's C&I rate classes, declining tiered volumetric energy charges for the GSP and GST rate classes stand out as non-standard compared to industry norms. Customers in these classes currently pay a higher volumetric energy rate (first tier rate) for the first 300 kWh of energy usage per kW of maximum demand and a lower volumetric rate (second tier rate) for additional energy usage. For example, if a customer's maximum demand is 50kW, they pay a higher volumetric rate for the first 15,000 kWh (300 kWh multiplied by 50 kW) and a lower volumetric rate for additional energy usage.

As Mr. Chriss also pointed out that this rate is unnecessarily complicated. I recommend that the Energy Bureau direct LUMA to implement a single energy charge equal to the (lower) second tier volumetric energy charge and an increased demand charge to recover the revenue lost from eliminating the tiered structure. I expect this change will not result in bill impacts for customers, but this change would simplify the rate structure and improve customer understanding.

Except for the GSS rate class, LUMA did not propose material changes to the rate design of C&I rates. Except for GSP and GST rate designs, LUMA's proposed C&I rate designs fall within industry norms. I therefore recommend that, except for GSS, GSP, and GST rate classes, the Energy Bureau adopt LUMA's proposed C&I rate designs.

N.2.b. Bill impacts of proposed rates

This section provides estimated bill impacts for customers on the GSS (General Service at Secondary Distribution Voltage) rate. Like the residential bill impacts section, this section compares the bill impacts of two proposed rates relative to existing rates for each rate class. Both rates recover LUMA's proposed revenue requirement using LUMA's proposed revenue allocation by rate class. This approach ensures an apples-to-apples comparison of the impacts of rate design independent from changes in total revenue requirement or revenue allocation. These rates do not include riders. The two rates are:

- **Existing Fixed Charge, Proposed Revenue** – maintains the existing fixed customer charge (as proposed by Mr. Datta) and increases volumetric charges in order to recover LUMA's proposed class revenue requirement.
- **LUMA Proposed** – LUMA's proposed rates.

For the GSS rate class, this section provides the following information:

- **Table of rate designs.** This table compares existing base rates with the two proposed rate designs.
- **Histogram of number of customers by monthly usage level.** Based on data provided by LUMA, this figure shows how many customers use electricity at different monthly usage levels.
- **Existing bills by usage level.** This figure calculates monthly bills under existing rates for the middle of each usage category. For example, for the 200-400 kWh/month category, this

figure shows monthly bills for a customer using 300 kWh/month. This section calculates bill impacts assuming the existing 18c/kWh total riders on top of the base rates.

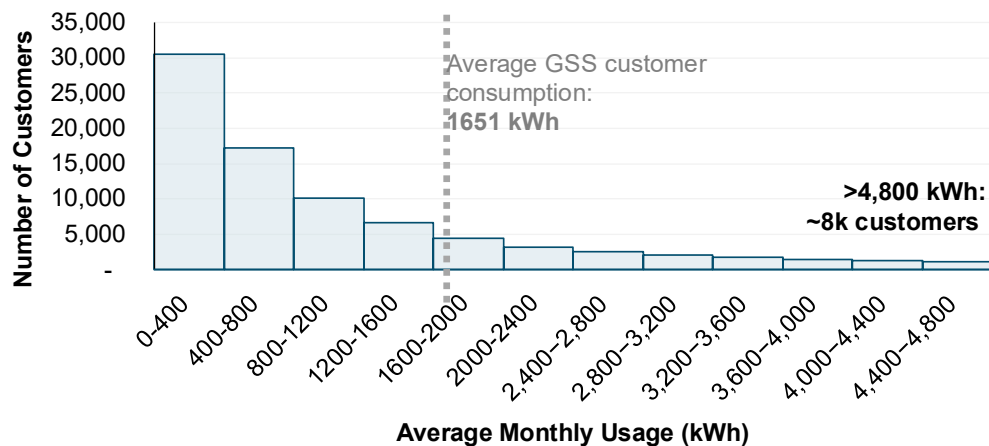
- **Change in bills by usage levels and rate design.** This figure shows the change in monthly bills expected for each usage level under the two proposed rate designs, compared to bills under existing rates. Because the level and design of future riders are not clear, this figure assumes no change to riders.

Table 28: GSS Rate Designs Modeled

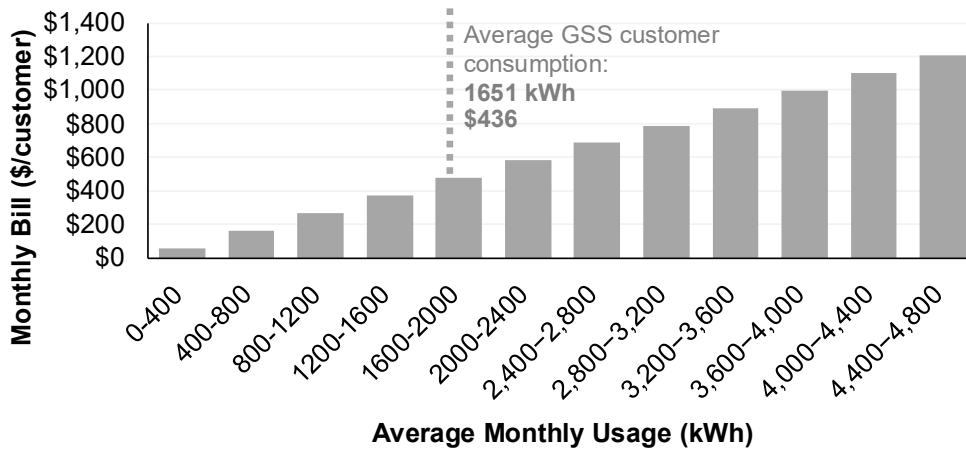
Design	Component	FY2026	FY2028
Existing	Fixed (\$/month)	\$5.00/month	\$5.00/month
	Energy (\$/kWh)	\$0.084/kWh	\$0.084/kWh
Existing Fixed Charge, Proposed Revenue	Fixed (\$/month)	\$5.00/month	\$5.00/month
	Energy (\$/kWh)	\$0.179/kWh	\$0.202/kWh
Proposed	Fixed (\$/month)	\$25.00/month	\$75/month
	Energy (\$/kWh)	\$0.167/kWh	\$0.160/kWh

Figure 14: Distribution of GSS Customer Usage and Bill Impacts

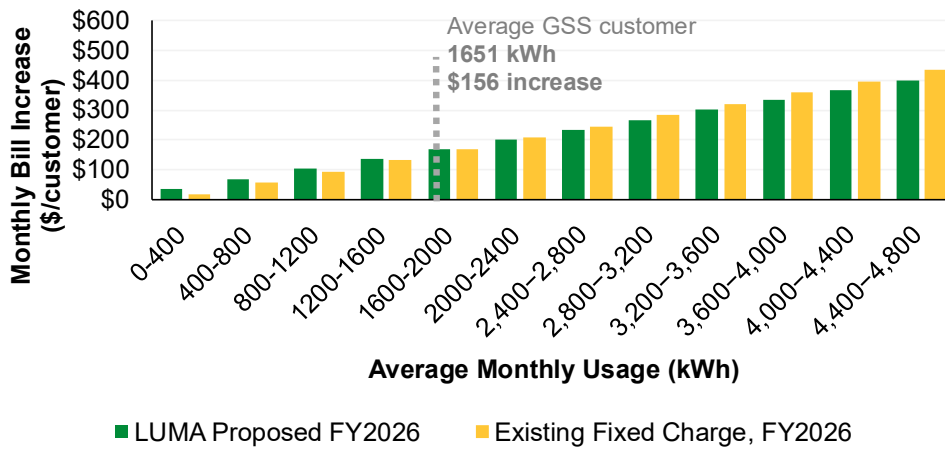
Average Monthly Consumption:



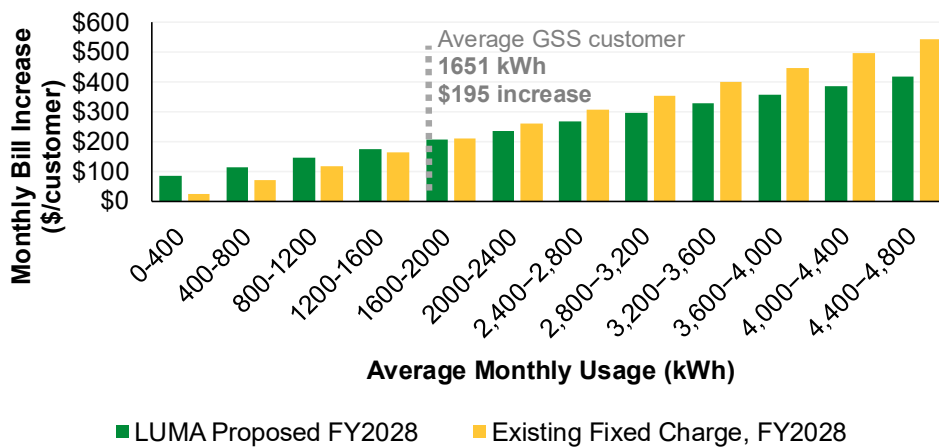
Existing Bills (including riders):



FY2026 Monthly Base Charge Increases (no change to riders):



FY2028 Monthly Base Charge Increases (no change to riders):



I evaluated whether LUMA's proposed GSS customer charge increase violates the principle of rate and bill stability.

I considered the impacts of LUMA's proposed customer charge on low-consumption GSS customers with energy usage between 0 and 400kWh/month, which is the most populous group in the distribution and includes one third of GSS customers. LUMA's proposed customer charge would increase bills for the GSS customers in this category by \$85/month relative to existing rates, which is more than the total existing bills (including riders) of \$58/month for customers in this category. This increase is driven by LUMA's proposed increase in the fixed charge from \$5/month to \$75/month, which has an outsized effect on small customers. LUMA's proposal does not meet the standards of gradualism.

Designing rates for the GSS class is challenging because the rate class includes customers with wide variation in electricity usage. One third of GSS customers use 0-400 kWh/month, the mean consumption for GSS is 1651 kWh/month, and over 10% of GSS customers use more than 8000 kWh/month. It is challenging to develop fair rates for this wide range of customer sizes without including demand charges.

There are two options to design a rate for these customers that fairly apportions costs. LUMA could either introduce a demand charge for the GSS rate class or split GSS into two or more rate classes based on maximum customer demand.

Changes to rate class definitions would require a detailed analysis of customer usage and developing a new COSS and revenue allocation. Thus, for this proceeding, I recommend that the Energy Bureau direct LUMA to reduce the GSS customer charge to \$25/month in FY2028. I also recommend that the Energy Bureau direct LUMA to, in future rate design applications, either separate the GSS rate class into two or more rate classes based on maximum demand or implement a demand charge.

N.3. Design of rate riders

LUMA proposed changing the CILT and SUBA riders from a volumetric rate design to a fixed monthly customer charge. LUMA proposed to continue allocating the revenues collected from these riders to rate classes based on class-level energy consumption.

From a rate design standpoint, it is reasonable for LUMA to collect CILT and SUBA riders through a customer charge. The costs of subsidies are not driven by the energy consumed by each rate class. Therefore, the principle of cost-causation indicates that these costs need not be collected through an energy charge.

Mr. Shannon said that the amount collected from the CILT and SUBA riders is uncertain after FY2026 because:

- "the reconciliation will be heavily impacted by the revenue requirement ultimately approved by the Energy Bureau;"
- "the removal of low-income subsidies from needing to be part of the calculation as they have been embedded in base rates;"

- “the provisional rate true-up.”²³⁹

I acknowledge that the uncertainty in the amount that will be collected in the CILT and SUBA riders. I nonetheless think it helpful to understand the magnitude of the proposed fixed charges of the CILT and SUBA riders, based on the current revenue collected by these riders. I have summarized the CILT and SUBA rider customer charge amounts in Table 29 based on the current volumetric charges for these riders and FY2026 billing determinants.

Table 29: Summary of volumetric and equivalent customer charges for CILT and SUBA riders.

Rider	Current Volumetric Rate (\$/kWh)	Equivalent Customer Charge with FY2026 Billing Determinants (\$/month)		
		GRS	LRS	GSS
CILT	\$0.00442	\$1.78	\$1.29	\$7.27
SUBA-HH	\$0.01256	\$5.07	\$3.68	\$20.67
SUBA-NHH	\$0.00109	\$0.44	\$0.32	\$1.80
Total CILT + SUBA	\$0.01742	\$7.03	\$5.10	\$28.67

LUMA currently collects the CILT and SUBA rider amounts from all customers. I recommend that low-income residential rate classes should be excluded from these riders. This would address several problems with collecting CILT and SUBA riders from low-income residential customer classes through a fixed charge:

- Based on the estimated rider amounts shown in Table 29, the CILT and SUBA customer charge riders would double the proposed fixed charge for the LRS rate class. The potential increase in total fixed charges collected from low-income customers is at odds with LUMA’s proposal to maintain a lower fixed charge for low-income customer classes.
- Mr. Datta also expressed concern that higher fixed charges, including CILT and SUBA riders, can disproportionately harm low-income customers. Exempting low-income customer classes would address this concern.
- The SUBA-HH rider currently collects the cost of the low-income discount. If SUBA-HH continues to collect the low-income discount cost (see discussion in Section I.2.b), it is counterproductive to provide low-income customers with a discount and then expect the same customers to contribute toward the cost of the discount.

Therefore, I recommend that the Energy Bureau accept LUMA’s proposal to collect CILT and SUBA riders through a fixed customer charge but exclude low-income residential rate classes from these riders.

N.4. Rate class definitions

Mr. Shannon noted that the General Service at Primary Distribution Voltage (“GSP”), GSP-TOU, General Service at Transmission Voltage (“GST”), and GST-TOU could be combined because

²³⁹ PC-of-LUMA-RATE_DES-7, part c.

“they have the same service characteristic (voltage level).”²⁴⁰ Mr. Chriss expressed concern with this suggestion, noting that “primary and transmission rate schedules have distinctly different service characteristics and cost allocated to them.”²⁴¹

Based on the limited information that LUMA provided on why combining primary and transmission rate classes might be appropriate, I do not think that it is reasonable for the Energy Bureau to consider combining rate classes. After this rate case, LUMA should evaluate the load characteristics (such as load factor and peak demand) of customers within both primary and transmission rate classes. The Energy Bureau should require a more thorough analysis of costs caused by customers within each class before considering combining classes.

Mr. Chriss also recommended that the Energy Bureau work to develop a rate specifically for public-facing Direct Current Fast Charging (DCFC) for EVs. This is a reasonable proposal given the unique load characteristics of DCFC EV charging. The expert report of Ms. Lane discusses the role of a DCFC rate in more detail.

N.5. Rate design impacts on Net Metering customers

This section presents my evaluation of intervenor positions on issues specifically relating to Net Metering (NM) customers. Some intervenors also refer to these customers as Net Energy Metering (NEM) customers.

Mr. Datta argued that LUMA’s proposed rate design will “adversely affect existing NEM customers due to a reduction in revenues, and will slow the adoption rate of new NEM customers due to longer payback periods, ceteris paribus, based on the existing revenue requirements.”²²² Mr. Datta’s argument is that an increased fixed charge would correspond to a lower volumetric charge, all else equal, leading to a longer payback period for rooftop solar customers and thus discouraging residents from moving to solar.

Mr. Datta disregarded the increase in revenue and rates in LUMA’s application. LUMA did not propose a reduction in the volumetric charge. Rather, LUMA proposed an increase in the volumetric charge that would actually lead to a significant improvement in the economics for rooftop solar relative to current rates.

To illustrate this, I calculated the payback period for DG systems under current and proposed rates. I used illustrative data inputs on solar cost and efficiency that are aligned with Mr. Datta’s estimate of an 8-year payback period.²⁴² I also considered LUMA’s existing rates and FY2028 proposed rates (see Table 20), taking the average of Tier 1 and Tier 2 base rates and adding all riders.²⁴³ I estimated that a 3 kW-DC system would cost \$8700, would provide \$1082/year in bill savings under existing rates, and would provide \$1564/year in bill savings under LUMA’s proposed

²⁴⁰ LUMA Ex. 20.0, p.29, ll.573-574.

²⁴¹ Walmart Ex. 1.0, p.32, ll.509-510.

²⁴² Solar cost of \$2.90/W-DC, DC-AC ratio of 1.2, and AC capacity factor of 22%. In practice, different solar systems will have different costs and efficiencies. These illustrative values were chosen to align with Mr. Datta’s description of an 8-year payback period under today’s GRS rates.

²⁴³ I assumed no change in rider rate design or values given the uncertainty around FY 2028 riders

FY2028 rates. This corresponds to an 8.0-year payback period under existing rates and a 5.6-year payback period under LUMA's proposed rates. This example illustrates that LUMA's proposed rates would lead to a dramatic improvement in the customer economics of NEM solar. Mr. Datta's concern that LUMA's proposal would damage the economics of NEM solar is unfounded.

Furthermore, Mr. Datta argues that the future adoption of NEM systems is a key concern for this proceeding. He argues that, if payback periods for NEM systems become longer, "fewer LUMA customers will be able to access capital, sign a lease or secure an affordable loan to install solar and storage, because the returns on the upfront investment will be lower."²⁴⁴ He argues that discouraging NEM investment would be especially detrimental due to capital constraints that PREPA and LUMA face.

Changes to rate design will affect investment and usage decisions for most or all distributed energy resources, not just NEM solar. These effects will vary for different kinds of resources and customer equipment. For example, given an approved revenue level, a rate design with higher fixed charges would worsen the economics of NEM systems but would improve the economics of electric vehicles and would increase customers' ability to utilize space cooling that could be necessary for comfort and health.

O. Recommendations on rate design

This section summarizes my recommendations to the Energy Bureau, as described in detail in the previous sections. This section is organized into recommendations that should be implemented within the current proceeding and those that must be implemented outside of the current proceeding due to time and resource constraints.

O.1. During the current proceeding

I recommend that the Energy Bureau adopt LUMA's proposed GRS customer charges. As explained in N.1.a., LUMA's methodology for calculating the GRS customer charge is reasonable, except for three issues that I identified. After correcting these issues, the customer-related costs in FY2028 are \$18.79/month. Nevertheless, because LUMA did not include demand-related costs in the customer charge, the \$20/month customer charge that LUMA proposed in FY2028 is reasonable. I also find that LUMA's proposed GRS customer charge has reasonable bill impacts that do not violate the principle of gradualism, as discussed in Section N.1.c.

I also recommend that the Energy Bureau adopt LUMA's proposed LRS and RH3 customer charges. LUMA's proposed customer charges appropriately balance collecting more revenue from customer charges given the higher annual revenue requirement, managing bill stability, and providing a discount to low-income customers, as discussed in Section N.1.a and N.1.c.

I recommend that the Energy Bureau deny LUMA's proposed GSS customer charge and direct LUMA to implement a \$25/month customer charge by FY2028. As discussed in Section N.2.b, the customers in the GSS rate class have a very wide range of monthly usage. Although LUMA's proposed customer charge is reasonable for a customer with the class-average usage, it results in

²⁴⁴ SESA Ex. 1.0, p. 29, ll.22-24.

an unreasonably large bill increase for the third of the rate class that has usage of less than 400kWh/month.

For the GRS customer class, I recommend that the Energy Bureau direct LUMA to implement a flat energy rate instead of an inclining block rate. As discussed in Section N.1.b, this change will better align the GRS rate with marginal costs while having a small impact on customer bills.

For the GSP and GST customer classes, I recommend that the Energy Bureau direct LUMA to implement a flat energy charge equal to the (lower) second tier volumetric energy charge and an increased demand charge to recover any revenue lost from eliminating the tiered structure, as discussed in Section N.2.a.

For C&I rate classes, except GRS, GSP, and GST, I recommend that the Energy Bureau adopt LUMA's proposed rate design methodologies, as discussed in Section N.2.a.

Except for the GRS, LRS, and GSS customer charges, I recommend that the Energy Bureau approve rate design methodologies, not rates values. The Energy Bureau should direct LUMA to recalculate rates for FY2026 based on the final revenue requirement decided within this rate case. To ensure that future rates use the best available data on billing determinants, for FY2027 and FY2028, LUMA should calculate rates each year based on the latest billing determinant forecasts.

0.2. After the current proceeding

It is not feasible for LUMA to implement some changes to rate design within the time and resource constraints of this proceeding. Nevertheless, the Energy Bureau should direct LUMA to implement the following rate design changes such that they can be implemented in future proceedings.

I recommend that the Energy Bureau direct LUMA to develop a robust plan to study and implement TOU rates in the coming years, such that TOU rates can be rolled out on a large scale as soon as possible, as discussed in Section N.1.b.

I recommend that the Energy Bureau direct LUMA to either introduce a demand charge in the GSS rate or separate the GSS rate class into two or more rate classes based on maximum demand, as discussed in Section N.2.a. These changes will improve the fairness of cost recovery from GSS customers.



44 Montgomery Street, Suite 1250, San Francisco, CA 94104
zachary.ming@ethree.com

ENERGY AND ENVIRONMENTAL ECONOMICS, INC.

San Francisco, CA

Partner

Mr. Ming leads E3's market design practice, with an emphasis on electricity systems operating under higher penetrations of renewable energy. He also has extensive expertise in resource planning, reliability and resource adequacy, regulatory and rate design issues, and distributed resource cost effectiveness. Recent projects include advising the Public Utility Commission of Texas on market reforms to improve reliability and studying pathways to net-zero carbon in Nebraska. Mr. Ming has been the lead author on several high-profile resource planning studies including *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*¹ and *Resource Adequacy in the Pacific Northwest*.²

Mr. Ming teaches a graduate level course at Stanford University titled *Electricity Economics* that provides a foundation of economic principles on the topics of regulation, planning, and operation of electric utilities, with a particular emphasis on emerging electricity sector topics such as renewable energy, energy storage, distributed resources, and market design.

Mr. Ming holds an M.S. in management science and engineering (energy and environment track) and a B.S. in civil and environmental engineering (atmosphere and energy) from Stanford University. Select projects at E3 include:

- **Market Design Reform Analysis, Public Utility Commission of Texas, 2022-2023:** Mr. Ming led analysis to evaluate the portfolio, reliability, and cost impacts of various market design reform proposals being contemplated in the ERCOT market. E3 published these findings in a report, and Mr. Ming publicly presented these results before the Commissioners at an open meeting and to state legislators.³
- **Capacity Value, Oregon Public Utility Commission, 2020-2022:** Mr. Ming developed a best practices framework for assessing the capacity value of for use in various Commission proceedings. Mr. Ming publicly testified before Commissioners at an open meeting to present results and answer questions.
- **Santee Cooper, the State of South Carolina, 2019-2020:** Mr. Ming managed an engagement with the State of South Carolina to advise on the potential sale of Santee Cooper, a state-owned utility with significant debt due to the abandonment of the V.C. Summer nuclear units 2 & 3. Mr. Ming testified before the South Carolina legislature to present the pros and cons of a potential sale, management arrangement, or reform of the utility.
- **Reliability Risk Model Assessment, PJM, 2021-2024:** Mr. Ming led a team that provided a detailed technical review of the probabilistic reliability risk model used by PJM to calculate capacity requirements and resource accreditation values (including renewables, storage, and thermal) for use in the PJM capacity market. Elements of the model that were reviewed include data inputs, assumptions, algorithms, methods of use, and results. Through this process, E3 made multiple suggestions for improvement to PJM staff.

¹ https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf

² https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

³ <https://interchange.puc.texas.gov/search/documents/?controlNumber=54335&itemNumber=2>

- **PURPA Expert Witness Testimony, South Carolina Office of Regulatory Staff, 2023:** Mr. Ming reviewed Public Utilities and Regulatory Policy Act (PURPA) filings submitted by South Carolina’s investor-owned utilities on behalf of the Office of Regulatory Staff. Mr. Ming reviewed for adherence to rate design best practices and application of avoided cost principles for both energy, capacity, and renewable integration costs. Mr. Ming testified before the South Carolina Public Service Commission to provide an overall assessment as well as recommendations for improvement.
- **Net Zero New England, Calpine, 2020:** Mr. Ming advised on a comprehensive economy-wide decarbonization analysis with a specific focus on the electricity sector. The analysis focused on the operating challenges at higher penetrations of renewables and the role of firm generation in the New England ISO under a net-zero carbon target.⁴
- **ISONE Capacity Market Design, Confidential Client, 2022:** Mr. Ming, on behalf of a confidential client, presented recommendations to the New England ISO (ISONE) on methods and improvements to better reflect winter reliability risks, particularly due to fuel constraints, in reliability risk modeling used in their capacity market.
- **Capacity Market Design, NYISO, 2022:** Mr. Ming advised the New York ISO (NYISO) on best practices for the adoption of a marginal effective load carrying capability (ELCC) framework within their capacity market construct. In 2022, NYISO became the first ISO to receive FERC approval for the implementation of a marginal ELCC framework. E3 also advised on technical implementation details including best modeling practices to balance both accuracy and simplicity.
- **Capacity Market Design, MISO, 2023:** Mr. Ming was retained by the Midcontinent Independent System Operator (MISO) to provide expert testimony regarding MISO’s filing before FERC to implement a “direct loss of load” methodology for use in their capacity market. Mr. Ming also led a team that provided advice on other topics including best practices for assessing local reliability requirements and determining which hours should be utilized in assessing reliability requirements.
- **Offshore Wind Reliability Analysis, Confidential Client, 2022:** Mr. Ming led a team to evaluate the reliability contribution of offshore wind in the PJM market for a confidential client. The team utilized detailed renewable output profiles to calculate effective load carrying capability (ELCC) values across a number of different future years and scenarios. The analysis determined that while offshore wind could make meaningful contributions to reliability, there remained a strong role for firm resources to ensure reliability across all conditions.
- **Firm Generation in Microgrids, Mainspring Energy, 2021:** Mr. Ming developed a report for Mainspring Energy evaluating the role of firm generation in local microgrids in California. E3 evaluated several different microgrid configurations including solar + storage, solar + fuel cell, and solar + Mainspring to determine that the lifecycle economics of solar + Mainspring were superior to alternative options, while providing equivalent emission and reliability outcomes.⁵
- **Renewable Reliability Value Analysis, Lincoln Electric System, 2022:** Mr. Ming oversaw a team that calculated renewable capacity values for Lincoln Electric System (LES) within the context of the Southwest Power Pool (SPP) market. The team calculated a forecast of ELCC values for wind, solar, and battery storage, which were provided to LES for use in their 2022 integrated resource plan.⁶
- **Renewable Effective Load Carrying Capability Analysis, Salt River Project, 2022:** Mr. Ming advised on a project to calculate the renewable effective load carrying capability (ELCC) values for wind, solar, and battery storage for Salt River Project (SRP). These values were used in SRP’s 2022 integrated resource plan.

⁴ https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

⁵ <https://www.ethree.com/wp-content/uploads/2021/03/The-Role-of-Firming-Generation-in-Microgrids-E3-and-Mainspring-Energy.pdf>

⁶ <https://www.les.com/sites/default/files/resource-items/irp-report.pdf>

- **Boulder Canyon Dam Pumped Storage Value Analysis, Los Angeles Department of Water and Power, 2019:** Mr. Ming led a team to evaluate the economics of converting Boulder Canyon Dam into a pumped storage facility to provide value integrating the increasing penetration of renewables in the Western interconnection.
- **Wholesale Market Tariffs, Nova Scotia Power, 2020-2021:** Mr. Ming developed testimony to support reforms to existing wholesale market tariffs to ensure they were consistent with best practices in competitive markets across North America.
- **Transmission Rate Design Analysis, AltaLink, 2017-2021:** Mr. Ming conducted rate design and regulatory analysis on the existing wholesale transmission tariff in Alberta and proposed alternative designs that were more aligned with cost-of-service principles.
- **Capacity Market Design, PJM, 2020-2021:** Mr. Ming provided advice to PJM on the incorporation of the effective load carrying capability (ELCC) metric into the PJM capacity market as a method to quantify the contribution of renewable energy and storage resources. Mr. Ming presented publicly the findings of the project at a PJM stakeholder workshop
- **Whitepaper Series, Regulatory Assistance Project, 2022-2023:** E3 worked with RAP to publish a series of whitepapers targeted to Chinese policymakers on topics related to energy and electricity. The whitepapers were published in English and Chinese and covered the topics of time-of-use ratemaking, integrating real-time pricing into rates, the value of long-term contracting, efficient capacity market mechanisms, the role of clean firm generation in a decarbonized electricity system, and the role of demand response and energy efficiency participation in capacity markets.
- **ERCOT Market Design, NRG, 2021:** Mr. Ming developed a whitepaper outlining a proposal to implement a load-serving entity reliability obligation (LSERO) product in the ERCOT market to both improve reliability and make the state less susceptible to scarcity pricing.⁷
- **California Hydrogen and CCS, Confidential Client, 2022:** Mr. Ming led analysis to evaluate the potential role and value of both hydrogen and carbon capture and sequestration (CCS) in California under the incentives of the Inflation Reduction Act.
- **Pathways to Net-Zero Carbon, Omaha Public Power District, 2021:** Mr. Ming led a study on behalf of OPPD to analyze pathways to net-zero carbon. The study found that significant quantities of wind, solar, and battery storage would be components of a least-cost/least-regrets resource plan, supplemented by firm resources for reliability such as natural gas or hydrogen. Mr. Ming led a series of six public stakeholder workshops to provide an opportunity for transparency and public input.
- **Long-Run Resource Adequacy under Deep Decarbonization Pathways for California, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of a high-renewable electricity system, consistent with California's long-term decarbonization goals of 80% by 2050. The report demonstrated that despite significant additions of renewable energy and storage, significant quantities of firm capacity were still needed to maintain sufficient reliability.
- **Reliability Value of Demand Response in California, CAISO, 2019-2022:** Mr. Ming led an effort to study the reliability impacts of demand response in the California electricity system using the effective load carrying capability (ELCC) methodology. The study showed that current methods overvalue the reliability value by 25-50%. Mr. Ming presented the findings publicly at multiple stakeholder workshops.
- **Resource Adequacy in the Pacific Northwest, Public Generating Pool, 2018-2019:** Mr. Ming authored a report analyzing the resource adequacy requirements of the Pacific Northwest under various low carbon electricity systems, including 100% carbon-free. This report was presented to multiple stakeholders and utilities in the region and has led to further discussions around resource adequacy coordination and planning.

⁷ https://www.ethree.com/wp-content/uploads/2021/09/LSE-Reliability-Obligation-E3-ERCOT-Whitepaper_2021-09-29.pdf

- **Once-Through Cooling Retirement Analysis, Los Angeles Department of Water and Power, 2017:** Mr. Ming managed a project analyzing the reliability implications of retiring three once-through cooling natural gas power plants in the Los Angeles basin and replacing them with a combination of clean resources including solar, storage, energy efficiency, and transmission. The results of this study were used to support the decision to retire all three plants and replace them with clean resources.
- **Planning Reserve Margin Study, Nova Scotia Power, 2019:** Mr. Ming led analysis to evaluate the required planning reserve margin (PRM) necessary to achieve a 1-day-in-10 year reliability standard in the province of Nova Scotia. The study also evaluated the contribution of several intermittent and energy-limited resources toward the PRM including solar, wind, energy storage, and demand response. This report was published publicly and formed a basis for Nova Scotia Power's 2020 integrated resource plan.
- **Integrated Resource Planning Support, Confidential Mid-Size Utility, 2018:** Mr. Ming managed a project evaluating the potential replacement of coal resources with renewable, energy storage, and natural gas resources in order to achieve decarbonization targets for a confidential mid-size utility.
- **Net Energy Metering Analysis, Various Clients, 2014-2017:** Mr. Ming performed analysis and published reports for various state utility commissions (California, Nevada, New York, South Carolina) evaluating the costs and benefits of net energy metering policies.
- **Heat Pump Analysis, New York State Energy and Research Development Authority, 2017:** Mr. Ming performed analysis on the costs and benefits of electric heat pumps to replace oil and natural gas heating in New York state as well as increase the efficiency of existing air conditioners. This work was published in a public report that led to the development of policies to incentivize heat pump adoption.
- **Resource Adequacy Program Design, Calpine, 2016:** Mr. Ming performed analysis on behalf of Calpine and presented to the California Public Utilities Commission (CPUC) to recommend the use of the effective load carrying capability (ELCC) metric in the Resource Adequacy (RA) program for wind and solar resources. The CPUC ultimately adopted this recommendation along with several market design features proposed by E3.
- **California Avoided Cost Calculator, California Public Utilities Commission, 2016-2018:** Mr. Ming led an update of the avoided cost forecast used to conduct cost and benefit analysis for demand-side programs in California, including energy efficiency, demand response, and distributed generation.
- **Title 24 Building Standard Development, California Energy Commission, 2016-2017:** Mr. Ming developed a forecast of future energy costs for the State of California used to establish building energy efficiency standards under Title 24.
- **Resource Value of Solar, Oregon Public Utilities Commission, 2016:** Mr. Ming contributed to expert testimony on the resource value of solar before the Oregon Public Utilities Commission.
- **Policy and Technology Scenario Analysis, Confidential Large U.S. Utility, 2015:** Mr. Ming modeled policy and technology-change scenarios for a large U.S. utility as part of their strategy planning process.

GENERAL ELECTRIC

Renewable Energy Development Program (REDP) Intern

Schenectady, New York

Summer 2012

CITIGROUP

Commodities Summer Analyst

Houston, Texas

Summer 2011

OGE ENERGY CORP (Enogex)

Capacity Management Intern

Oklahoma City, Oklahoma

Summer 2010

MAP ROYALTY

Oklahoma City, Oklahoma

Engineering Intern

Summer 2009

Education

Stanford University

M.S., Management Science and Engineering (Energy and Environment)

Stanford, California

2013

Stanford University

B.S., Civil and Environmental Engineering (Atmosphere and Energy)

Minor in Economics

Stanford, California

2012

PC Ex. 61.02

ROIs

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-8

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: LUMA Ex 4.04 (7.03.25) Customers Forecast 2025 Update, “Customer Estimated 2025” tab, cell E14

Preamble: In LUMA Ex 4.04 (7.03.25) Customers Forecast 2025 Update, the “Customer Estimated 2025” sheet, cell E14 appears to estimate the customer count in each rate class by applying the average monthly variance to the remaining months in FY2025.

Question: Why does the residential rate class customer forecast use the average monthly variance from only August, September, December, and January, instead of averaging all months?

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

LUMA performs multiple estimations and selects the one that best aligns with the most recent observed customer behavior. Residential customers represent over 90% of the total customer base, significantly influencing revenue. As such, any overestimation in this segment could adversely affect the revenue requirement. Utilizing the average variance of 455 customers each month (consistent with the other customer class) for the remaining months results in an estimated increase for 5,463 customers when comparing June 2025 to June 2024. This growth is significantly higher than the observed increase of 2,792 comparison between June 2024 and June 2023. Therefore, LUMA selected for the estimation an increase of 42 customers to the remaining months from fiscal year 2025 (March through July 2025) based on the average observed incremental monthly variances for July to August 2024, August to September 2024, November to December 2024 and December 2024 to January 2025. This selection resulted in a total increase of 4,224 customers in comparison to June 2024, which is more closely aligned to the previous year's growth.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-7

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: Joseline N. Estrada-Rivera Testimony, page 9-11, Q.27

Preamble: Ms. Estrada-Rivera's testimony states: "LUMA uses data from customers enrolled in the net metering ("NM") program as a proxy, as LUMA does not have visibility into customers who have distributed photovoltaic or "PV" systems but do not participate in the NM program."

In addition, the testimony states: "Key assumptions incorporated into the model include:

- Macroeconomic & Policy Factors: The forecast is based on historical adoption trends and assumes a continuation of existing conditions. While external factors such as economic conditions, regulatory changes, and grid reliability can influence PV adoption, these are not explicitly included in the model and could cause deviations from the forecast growth.
- Technology Saturation: The model recognizes that adoption will not continue indefinitely and includes a natural ceiling to PV growth, avoiding overestimation."

Questions:

- a. Please explain why a customer may have distributed PV but not participate in NM.
- b. Why are economic conditions and regulatory changes not included in the PV adoption forecast?
- c. What assumptions were used for the natural ceiling to PV growth?
- d. Please provide historical data or estimates showing the adoption of battery storage systems that have been installed with distributed PV.
- e. Please explain what assumptions were made about the adoption of battery storage systems in the development of the DG adoption forecast.
- f. Please explain how the impact of battery storage systems has been taken into account in the development of distributed PV load shapes.

Rate Review

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. A customer may have a distributed photovoltaic (PV) system without participating in a Net Metering (NM) program if the customer chooses to operate its PV system entirely independent of the utility grid.
- b. Economic conditions and regulatory changes were not included in the PV adoption forecast because historical data and market analysis show economic conditions and regulatory changes are not the primary drivers of adoption in Puerto Rico. The forecast instead focuses on the most influential factor: the pursuit of energy reliability.

Reliability outweighs economics:

- In Puerto Rico, the decision to install a solar PV system is overwhelmingly driven by a need for reliable power rather than cost savings. Energy is a fundamental necessity, and LUMA's analysis demonstrates that the primary motivation for customers is securing an autonomous and stable source of electricity.
- During the past five fiscal years, the average bill for low-income customers with 300 kWh of consumption fluctuated between \$50 and \$100. Average consumption of a customer under the General Residential Service rate (GRS) was 440 kWh and the average bill fluctuated between \$80 to \$135. The billed amount for both kinds of customers is less than the average monthly payment for a PV system which LUMA estimates to be approximately \$140 to \$180.

Stable regulations and market deceleration:

The forecast's methodology was further shaped by two key observations:

- **Stable regulatory environment:** The law governing net energy metering (NEM), which mandates one-to-one credit for solar customers, is not expected to change before 2030 the date of a study that was mandated. With no anticipated regulatory shifts within the forecast period, this variable becomes constant rather than a factor of change.
- **Slowdown adoption rate:** The primary challenge was to predict the market's saturation point, or "ceiling." We have observed a clear trend of slowing growth in new solar installations. The month-over-month customer increase has decelerated from an average of 4% in FY2022 down to 3% in FY2024 and 2% in FY2025. Monthly observed data over the past two years indicate that following blackout events, customers increased new solar installations above the prior month's trends, subsequently, new solar installation trends have shown decelerations.

Given that the main driver (reliability) is non-economic, the regulatory framework is stable, and recent economic conditions have been uncertain (as of February 2025), the most logical

Rate Review

approach was to forecast the adoption ceiling based on the observable trend of market deceleration.

- c. The natural ceiling for PV growth in the forecast is not a predetermined value but is a calculated output of the Gompertz Growth Model. The model was selected for its documented ability to forecast non-linear, S-shaped adoption curves, which are characteristic of new technology integration.

Forecasting methodology: The Gompertz Growth Model:

- The Gompertz Growth Model is a standard statistical tool used to describe a process of growth that begins slowly, accelerates, and finally slows as it approaches a maximum level, or saturation point.
- The model analyzes the historical PV capacity data (from July 2021 to February 2025) to estimate the parameters of the growth curve. The key parameter in this context is (K), which represents the asymptotic maximum capacity, or the "natural ceiling." It is the upper limit of the model projects the market will reach if it continues to follow the observed growth trend.

Foundational assumptions for the natural ceiling. The calculation of the natural ceiling rests on the following key assumptions:

- **The principle of market saturation:** The forecast is built on the fundamental economic principle that adoption does not continue indefinitely. It assumes the PV market will follow a life cycle that includes a saturation phase, thereby justifying the existence of a "ceiling."
- **The ceiling is statistically derived from historical data:** The specific value for the natural ceiling (K) is not a manually selected input or an external assumption. It is a parameter estimated by the model's non-linear least squares (NLS) function. The model derives this value by fitting the Gompertz function to the actual, historical adoption data, making the ceiling a direct, data-driven extrapolation of the observed trend.
- **Continuation of existing conditions:** The model assumes that the underlying market conditions, customer behavior, and policies that drove PV adoption during the historical period (July 2021 - February 2025) will continue into the forecast period. The model, therefore, explicitly excludes speculation on potential future events, such as legislative changes, major economic shifts, or unforeseen technological advances.

- d. Please refer to file *PC-of-LUMA-LOAD_FOR-7_Attachment 1*.
- e. No direct assumption regarding battery storage was made in the development of the distributed generation (DG) adoption forecast. The model's methodology makes a specific assumption about battery adoption rates unnecessary. The rationale is as follows:
- **Forecast objective:** The primary objective of this forecast is to project future energy consumption from the utility grid, which serves as the basis for revenue forecasting.
 - **Core assumption:** The model operates on the foundational assumption that all energy generated by a customer's DG system is used to offset that customer's grid consumption.
- f. The impact of battery storage systems was not explicitly modeled in the development of the distributed PV load shapes because empirical data from the preliminary load profile study indicates that customers are primarily using their batteries for backup reliability, not for daily economic load-shifting.

Rate Review

Analysis of observed load profile data:

The evidence for this conclusion is found in the figure 7-1 below, which compares the average hourly consumption patterns of customers with and without PV systems.

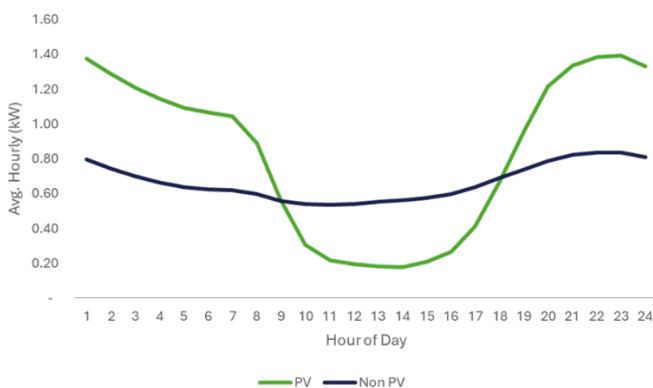
- **Mid-day consumption:** The graph shows that during peak solar production hours (approximately 9:00 to 18:00), the grid consumption of PV customers drops significantly, creating the characteristic "duck curve." This is expected, as their on-site solar generation powers their homes and potentially charges their batteries.
- **Evening peak consumption:** During the evening hours (from 18:00 onward), PV customers' consumption from the grid rises sharply. Their evening peak demand is not only present but is, on average, higher than that of non-PV customers.

This evening consumption pattern is the key indicator of how batteries are being utilized.

- If customers were using their batteries for daily load-shifting or economic optimization, they would discharge them during the evening to power their homes. This would result in a lower evening peak consumption from the grid compared to non-PV customers.
- The fact that their grid consumption is higher demonstrates that they are not using their stored energy. This strongly supports the conclusion that batteries are being kept at or near a full state of charge in the evenings, reserved exclusively for backup power in case of a grid outage.

Since the observed data shows that batteries are not being used in a way that materially alters the daily shape of energy demand from the grid, it was determined that a separate model for their impact was not necessary for this analysis.

Figure 7-1. Average Hourly Load Profiles: PV vs Non-PV Customers



Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada-Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-9

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: Sam Shannon's Expert Testimony Q44, Q58, Q62, Q63 (page 22, 25, 26), "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks

Preamble: As stated in Mr. Shannon's testimony: "The revenue allocations attempted to balance three goals. First, given the size of the overall increase requested in the rate case, no customer class should receive a decrease from present rates. Second, low-income residential customers' increase should be capped at a maximum of 30 percent. Finally, no class should receive an increase greater than two times the overall utility percentage increase." (Q44, page 22)

Further, Mr. Shannon's testimony explains that "The Utility's proposed rate design increases the customer charge for residential customers year-over-year up to \$20.00 per month by the 2028 test year. This will bring the customer charge in line with the total amount of customer-classified costs." (Q58, page 25) Table 7 provides a summary of customer classified costs for GSS and GRS customer classes. In addition, the customer charges for GRS and GSS are calculated on the Functional Costs sheet of the "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks.

In Q62, Mr. Shannon explains that "The RFR monthly charges are established by statute, so they cannot be changed in this rate case. I maintained a similar ratio to the status quo of customer charge rates between the GRS customers and the LRS/RH3 customers resulting in lower customer charges for these low-income rates."

Mr. Shannon explains that "[t]he rate design is shown in Schedule K" for all other rate classes.

Questions:

- a) Please confirm that the only details about the rate design methodology that have been provided are summarized in the preamble to this question.
- b) If not confirmed, please provide all references where additional details of the rate design methodology have been provided.
- c) Please explain why the 34.18% and 39.47% increase in revenue allocation to the LRS and RH3

Rate Review

customer classes respectively (LUMA - Rate Design Schedules FY2028 (7.03.25).xlsx, Revenue Summary w Riders tab, cell J16:J17) is not aligned with the principle that “low-income residential customers’ increase should be capped at a maximum of 30 percent.”

d) Please explain why the 138.11% increase in revenue allocation to the USSL customer class (LUMA - Rate Design Schedules FY2028 (7.03.25).xlsx, Revenue Summary w Riders tab, cell J22) is not aligned with the principle that “no class should receive an increase greater than two times the overall utility percentage increase.”

e) Please explain why the revenue allocation to the GRS customer class in FY2028 does not reach 40.8% as indicated by the COSS (LUMA - Rate Design Schedules FY2028 (7.03.25).xlsx, Cost Allocation tab, cell E78 divided by cell D78) in FY2028 while also not reaching the maximum increase described by the principle that “no class should receive an increase greater than two times the overall utility percentage increase.” Please include a description of any policy objectives that are underlying the limited increase in revenue allocation to the GRS customer class.

f) Please describe any principles or guidelines, other than those included in the pre-amble to this question, that were used to determine the proposed revenue allocation. This includes any relationship between existing revenue allocation and proposed revenue allocation, as well as any relationship between the cost allocation from the COSS and the proposed revenue allocation.

g) Please provide all calculation details showing the derivation of the customer charges for all customer classes other than GRS, GSS, and RFR (which were specifically referred to in Mr. Shannon’s testimony and for which calculation details have already been provided). If no calculation details are available, please provide any additional principles or guidelines that LUMA followed to come up with its proposed customer charges.

h) Please provide all calculation details showing the derivation of the demand charges for all applicable customer classes. If no calculation details are available, please provide any additional principles or guidelines that LUMA followed to come up with its proposed demand charges.

i) Please provide all calculation details showing the derivation of the tier1, tier 2, and tier 3 (where applicable) energy charges for all applicable customer classes. If a consistent ratio or cents/kWh differential between tiers was used, please describe. If the energy charge for the first tier is designed to result in a specific bill or bill impact to certain customers, please describe. Please provide any additional principles or guidelines that LUMA followed to come up with the ratio or differential between tiers of the tiered energy charges.

j) Please explain how LUMA proposes that changes to the cost allocation calculated in the COSS be reflected in the revenue allocation. Please include an explanation of how an increase or decrease of the cost allocation to the GRS customer class in the COSS will impact the revenue allocation to the GRS customer class.

k) Please explain how LUMA proposes that changes to the total revenue requirement be reflected in the revenue allocation and rate design. For example, all rates could be increased by a consistent percentage. Alternatively, fixed and demand charges could be fixed at LUMA’s proposed rates and all changes to revenue could be reflected in volumetric rates. Please provide as much detail as possible.

Rate Review

RESPONDER

Sam Shannon

RESPONSE

- a. No. Please refer to the response provided under question b for further details.
- b. For details of the rate design methodology that have been provided, please refer to my testimony, specifically the response to Question 50, which outlines the principles from Bonbright. Additionally, Sections D, E, and F of my testimony contains discussion on various considerations used in setting the rates to generate the proposed revenues by customer class.

Question 63 in my testimony contains a typo; it should reference Schedule M for the rate design.

- c. The premise of the question is incorrect. When the entire subsidized population is viewed as a whole, including the Residential Fixed Rate for Public Housing Under Ownership of the Public Housing Administration (RFR) customers, the increase is less than 30 percent. Please refer to tables 4, 5, and 6 in my testimony.
- d. The premise of the question is incorrect. There is no inconsistency between the principles and my proposed revenue allocation. Unmetered Service for Small Loads (USSL) makes up part of the broader Small Commercial customer class. As a whole, Small Commercial customers receive a 36.55 percent increase in FY2026. Please refer to tables 4, 5, and 6 in my testimony.
- e. As described in my testimony, the principles referenced serve as guideposts, rather than mandates. The proposed revenue allocation reflects a gradual approach to the increasing rates for residential customers over the three test years, with a focus on mitigating impacts to those customers to the greatest extent possible. As stated in the 2017 rate order¹, cost of service (COSS) provides a guide to revenue allocation, but is not prescriptive.
- f. As described in response to b. above, the principles described in my testimony also include the Bonbright principles and other considerations described in Sections D, E and F. Those are the principles used in the revenue allocation. Attempting to maintain current revenue allocations would be unreasonable as they do not take into account the changes to the Puerto Rico Electric Power Authority (PREPA's) system and energy use in Puerto Rico since 2017. As stated in the 2017 rate order², cost of service provides a guide to revenue allocation, but is not prescriptive.
- g. I did not prepare a functionalized cost analysis for the other customer classes. Lifeline Residential Service (LRS) and Residential Service for Public Housing Projects (RH3) customer charges are set lower than the General Residential Service (GRS) class in line with the Puerto Rico Energy Bureau (PREB's) policy as described in the 2017 rate order³ of setting lower rates for these customer classes as an embedded discount. The other rate classes have demand charges which limit the importance of customer charges to these customers and to the utility.

¹ Final Resolution and Order of January 10, 2017, Docket No. NEPR-AP-2015-0001.

² *Id.*

³ Final Resolution and Order of January 10, 2017, Docket No. NEPR-AP-2015-0001.

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- h. The proposed demand charges are not calculated. Demand rates present an additional consideration in ratemaking in that bill impacts will vary with a customer's load factor. My rate design attempts to balance the potential bill impacts among low and high load factor customers.

Mathematically, if the increase to a demand rate is primarily on the demand charge, that will disproportionately impact low load factor customers. Conversely, if the increase is primarily on the energy charge, the high load factor customers would bear the brunt of the increase. Balancing the impact to the various customers within a demand class requires adjustments to the rates to achieve a smoother distribution of bill impacts as shown in Schedule M-3 and M-4.

- i. I do not know what is meant by tier 3 rates. The tiered rates are not based on any fixed ratio or other calculations. The rates for each tariff must generate sufficient revenue to meet the revenue requirement and still send a price signal to encourage energy conservation. Given the proposed increase to the customer charges, the tier 1 energy charges have less impact on the overall bill increases for customers.
- j. At this time, LUMA does not propose any changes to the revenue allocation based on the cost allocation calculated in the COSS. When other parties propose alternatives for cost allocation, we will evaluate those alternatives using the same principles of gradualism and relation to the COSS.

There are multiple reasonable approaches that LUMA could take under that scenario. For example, if the PREB or another intervenor proposes a cost allocation that increases the GRS share, then on rebuttal, LUMA could increase the GRS revenue allocation by the same amount. Alternatively, LUMA could propose to temper the increase to GRS by sharing across multiple customer classes. If the proposed increase in cost responsibility exceeds the LUMA's maximum increase preference to GRS, LUMA could also propose not to adjust the revenue allocation upward. As the PREB has rightly stated, cost allocation is a guide, not a prescription. This gives the LUMA and PREB wide latitude in translating the deficiencies in the COSS to actual revenue allocation and rates.

- k. The level of customer charges for GRS and General Service at Secondary Distribution Voltage (GSS) are discrete proposals, and while the PREB may adopt a modified revenue allocation to these classes, LUMA would not propose modifying these rates as part of the final rate design.

Beyond that, LUMA believes that both examples provided in the question could possibly represent reasonable alternative rate designs, however, LUMA reserves the right to comment on this on rebuttal in response to an actual proposal. For example, it may be reasonable and easier to implement to use constant percentages to inflate/deflate the other rate components. However, to the extent that the PREB wants to use cost allocation as a guide to aligning the final revenue allocation with the authorized revenue requirement, that may also be a reasonable approach. For example, if the PREB decides to increase distribution spend, those costs may translate to all customers except General Service at Transmission Voltage (GST), who are not allocated any distribution costs. Or the PREB may decide to change the spending amount on customer service functions, which impact smaller customer classes more. Without a concrete alternative proposal to evaluate, it is not possible to determine which issues in the revenue requirement are likely to be contested by the parties and PREB's consultants, thus, it is premature for LUMA to provide a recommendation on impacts to revenue allocation.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE-DES-12

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: LUMA - Rate Design Schedules FY2026 [2027,2028] (07.03.25).xlsx, LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update.xlsx, Joseline N. Estrada-Rivera Testimony

Preamble: The billing determinants used to calculate cost allocation and rates in the LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx workbook are shown in the 2026 Forecast sheet (similarly for 2027 and 2028).

The explanation of the load forecast development is provided in Joseline N. Estrada-Rivera's testimony and the accompanying LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update.xlsx workbook.

Questions:

a) Please explain how the energy billing determinants by rate class used in the cost allocation and rate design (2026 Forecast sheet , F25:H101 in LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx) is derived from the energy load forecast by rate class (FP approved Load w Modifiers sheet of the LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update.xlsx). Please explain and provide calculations that show how the total load be aggregate rate class (e.g. residential) is broken down into individual rate classes (e.g. GRS). Please explain and provide calculations that show how the total load by rate class is divided into first and second tier, where applicable (labelled "Primer Bloque" and "Segundo Bloque").

b) Please provide the source and any supporting calculations for the number of customers billing determinants by rate class used in the cost allocation and rate design (2026 Forecast sheet , E25:E101 in LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx).

c) Please explain and provide supporting calculations to show how the demand billing determinants by rate class used in the cost allocation and rate design (2026 Forecast sheet , L25:O101 in LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx) are derived from the peak demand forecast by rate class (Load w Modifiers Peak demand sheet of the LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update.xlsx). Please provide any additional sources for the demand billing determinants in the 2026 Forecast sheet in LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx workbook.

Rate Review

RESPONDER

Sam Shannon and Joseline Estrada

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. Joseline Estrada: Customer and kWh distribution by rate was based on the observed data for calendar year 2024. The distribution reflects actual customer count and energy consumption by rate class. Refer to Excel file 'PC-of-LUMA-RATE-DES-12' for full traceability—formulas remain intact for July 2025. All monthly and fiscal year values were determined using the same methodology documented within the Excel file.
- b. Joseline Estrada: See the response (a) above.
- c. Joseline Estrada: See response (a) above.

Sam Shannon: The additional source is that for excess demand units, the units are not part of the load forecast. Therefore, the prior year's actuals were used to forecast the billing determinants for the test years.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

I, Joseline Estrada, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline Estrada

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST-ALL-14

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026 [2027,2028] (07.03.25).xlsx

Preamble: Several capital expenses, specifically Substations, Control Center & Buildings, and Enabling Costs, are quantified in cell D292:D323 of the Cost Allocation sheet of “LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx” workbooks but are not discussed in Mr. Shannon’s testimony.

Questions:

- a) Please explain the types of substations included in the Substations capital expense category to justify their allocation with a 1CP allocation factor. Please explain whether these costs include the cost of substations contained wholly within the distribution system.
- b) Please explain why Enabling expenses are allocated based on Demand – NCP.
- c) Please explain why Control Center & Buildings are allocated based on Energy.

RESPONSE

Sam Shannon and Pedro Melendez

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a) **Pedro Melendez:** PBUT7, PBUT8 and PBUT18 include all of LUMA’s substations sites, which include transmission centers, distribution substations and switching centers. LUMA notes that it does not include third party-owned substations.

Sam Shannon: These costs include substations that only provide support to the distribution system; however, the costs cannot be separated at this time. When the Puerto Rico Electric Power Authority (PREPA) moves to Federal Energy Regulatory Commission (FERC) accounting, distribution and transmission substations will be recorded separately. Absent more discrete information, a 1CP allocator for substation costs is reasonable.

Rate Review

- b) **Sam Shannon:** Based on the description of the costs, allocating these items the same way as distribution capital is a reasonable option.
- c) **Sam Shannon:** Based on the description of the control station costs, these items could be considered similar to administrative costs that an independent system operator (ISO) would have. Therefore, allocating these costs by production energy is a reasonable approach.

Attestation

I, Pedro Melendez, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Pedro Melendez

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE-DES-11

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: Sam Shannon's Expert Testimony Q90, Q91 (page 35, 36), "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks, LUMA Schedule O-2 Tariff - PROPOSED_Red Lined (7.03.25)

Preamble: As stated in Mr. Shannon's testimony: "For non-firm energy exported by a customer, I propose that the avoided cost rate be set equal to the FCA". Mr. Shannon further elaborates that for firm QF generation, he proposes to use the FCA plus a capacity adder which would be calculated as "The average-excess demand percentage was applied to the fossil generation power purchase agreement contracts to arrive at the amount PREPA pays these generators for capacity. Using this method, the capacity adder is \$0.0142/kWh." (Q90, page 35)

In Q91, Mr. Shannon's explains that "The current QF rider has different prices based on the voltage level that the customer takes service at. This makes sense because it is best practice to incorporate the effect of losses that the Utility has to incur in delivering power. Oddly, the export rates increase as the customer takes service at lower voltage. This is the opposite of how the loss factors should be incorporated into the export credits. A power exported to the primary distribution network will have lower losses associated with final delivery than power exported at secondary voltage. Therefore, while I continue to incorporate loss factors into the setting of the export rates, I have reversed the relationship so that the base export rates discussed above apply to transmission service customers and decrease with the voltage level." (Q91, page 36)

Questions:

- a) Please explain the methodology and provide all calculation details behind the "Compensation for Firm Generation" and "Compensation for Non-Firm Generation" in the Payments to Qualifying Facilities Rider of the currently adopted tariff book.
- b) Please provide all calculation details showing the derivation of the capacity adder value of \$0.0142/kWh.
- c) Please explain or provide a source with the definition of a Firm QF generator.
- d) Please confirm that, by applying a higher loss factor to QF generators connected at lower voltages, Mr. Shannon is assuming that energy from QF generation will be transmitted over the distribution and

Rate Review

transmission systems instead of being consumed locally.

e) If (g) is confirmed, please provide evidence that energy from QF generation will be transmitted over the distribution and transmission systems instead of being consumed locally.

f) Please provide precedents from other jurisdictions where the rates for QF generators are lower for distribution-connected generators as compared to transmission-connected generators.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. I do not have any calculations or explanations of methodology behind the rates in the current tariff book.
- b. The capacity adder rate is the same as was used in the wheeling docket for capacity-related value. Please see PC-of-LUMA-RATE_DES-1_Attachment 1 for the calculation.
- c. The definition of Firm QF Generator is the same as the definition in the current tariff. I do not have historical information as to how that definition was set.
- d. Confirmed, I assume that generation paid under the QF tariff will be transmitted across PREPA's distribution/transmission system.
- e. We assume that the reference to (g) is a typographical error and should be a reference to (d). Based on that assumption, I explain that any generation that is consumed onsite will not flow through the meter, so it cannot be billed, and therefore does not need to be credited. Only the output flowing through the utility's meter will be billed and credited with the amount in the QF tariff.
- f. As an example, see Madison Gas & Electric's Parallel Generation Buyback rates, schedule MSC-2.¹

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

¹ <https://www.mge.com/MGE/media/MGE-Library/documents/rates-electric/electric-rates-20250701.pdf>

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-13

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: Sam Shannon's Expert Testimony Q31 (page 13, 14), "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks

Preamble: Mr. Shannon's testimony notes that "I used a 1CP allocator to assign transmission costs to the customer classes... The bulk power system must be built to accommodate the maximum load on the system, plus a reserve margin. That single hour of the year determines how the transmission system will be built, and, therefore, the 1CP allocator best reflects the design of the transmission system." (Q31, page 13-14).

Questions:

- a) Please provide historical hourly system load for all available years.
- b) Please explain and provide evidence to support the use of a 1CP allocator for all transmission costs. Please explain why other demand allocators such as 4CP or 12CP are not appropriate for the allocation of transmission costs in Puerto Rico.
- c) Please explain why no transmission costs are classified to energy.
- d) Please provide details of the transmission system topology, including details of infrastructure that has been built to deliver renewable energy or other remote generation that is sited away from load centers.

RESPONDER

Sam Shannon and Pedro Meléndez

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Rate Review

- a. **Sam Shannon:** Please refer to *PC-of-LUMA-COST_ALL-13_Attachment 1* for historical hourly system load from FY2021 – FY2025.
- b. **Sam Shannon:** As described in my testimony, the transmission system is built to support the peak hour's load for the entire system. In my judgement, a 1CP allocator most accurately depicts this purpose.
- c. **Sam Shannon:** The peak load of the system is a function of instantaneous demand, therefore it is classified and allocated entirely to demand, not energy.
- d. **Pedro Meléndez:** Please refer to *PC-of-LUMA-COST_ALL-13_Attachment 2*.

Confidential Information: PC-of-LUMA-COST_ALL-13_Attachment 2 is a map of the Puerto Rico Energy Transmission System. Said information constitutes Critical Energy Infrastructure Information ("CEII"), that is not common knowledge, is not made publicly available, and if disclosed to the public, will expose key assets to security vulnerabilities or attacks by people seeking to cause harm to the systems. Therefore, it is in the public interest to keep the information confidential.

Pursuant to the Energy Bureau's Policy on Management of Confidential Information, CEPR-MI-2016-0009, issued on August 31, 2016, as amended on September 21, 2016 ("Policy on Confidential Information"), confidential designation is a reasonable and necessary measure to protect critical infrastructure from attacks and to enable LUMA to leverage information without external threats. In compliance with the Energy Bureau's Policy on Confidential Information, under separate cover and expediently, within the next ten (10) days, LUMA will submit a memorandum of law in support of its request to file PC-of-LUMA-COST_ALL-13_Attachment 2 confidentially.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

I, Pedro Meléndez, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Pedro Meléndez

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-10

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: Sam Shannon's Expert Testimony

Questions:

- a) Please describe any instructions that Mr. Shannon received regarding the policy goals of the rate design. Please include who provided the instructions and their position and organization name. Please provide a copy of all written communication and summarize all oral communication.
- b) Please confirm that discretion or interpretation was required in order to incorporate the instructions described in (a) into the rate design.
- c) If (b) is confirmed, please explain, in detail, what discretion or interpretation was used when incorporating the instructions describe in (a) into the rate design. Please be as specific as possible.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA hereby provides its response to the Request and includes herewith the information and/or documents responsive to the Request identified after a diligent search and reasonable inquiry. LUMA remains committed to updating or supplementing this response with additional responsive information, if any is located, after completing its diligent search and reasonable inquiry.

- a. To clarify the process that was conducted regarding my recommendations concerning the policy goals of the rate design and the customer charges that I proposed in my testimony, it is important to understand the full sequence of events of developing my rate design proposals. First, as discussed in my testimony, I prepared a cost-of-service study myself and a revenue allocation.

(See my Testimony. LUMA Exhibit 20.00 at Sections B “Electric Cost of Service” and C. “Revenue Allocation”).” In the revenue allocation process, I developed three specific principles to recommend to LUMA relying on my extensive experience designing rates both at the Wisconsin Public Service Commission and as an expert rate consultant. First, given the size of the overall increase requested in the case of the rate, no customer class should receive a decrease from the present rates. Second, low-income residential customers’ increase should be capped at a maximum of 30 percent. Finally, no class should receive an increase greater than two times the overall utility percentage increase.

After those steps, I developed my rate design proposal and proposed customer charges, as described in my testimony at D “Rate Design,” and E “Customer Charge.” For the rate design step, I attempted to adhere to the general principles for rate design described by James Bonbright, as discussed in my testimony at 21. Some of these general principles for rate design include consideration of issues such as the practicality of the rate design in terms of understandability, effectiveness in yielding total revenue requirements, revenue stability from year to year, stability of the rates themselves, with a minimum of unexpected changes, fairness in the apportionment of total costs, avoiding undue discrimination, etc. Based on the results of the costs of service study and revenue allocation, and in consideration of the general principles of Bonbright, I attempted to balance these principles to achieve a comprehensive rate design.

Based on my analysis of the cost of service study impacts on the residential customer classes for GRS and GSS, I determined that the customer charges for residential customers year-over-year need to increase up to \$20.00 per month by the 2028 test period, I developed a proposal for a phased-in approach to increasing the General Residential Service (GRS) and General Service at Secondary Distribution Voltage (GSS) customer charges starting with \$10 and \$25 per month growing to \$20 and \$75 per month, respectively, consistent with the principle of gradualism.

Once I completed all of these steps, I then briefed the LUMA rate case steering committee on the results of the cost-of-service study, my recommended three rate design principles for revenue allocation discussed above, and my proposed customer charges that I had developed. I asked the steering committee to approve my proposed cost allocation principles and the proposed customer charges that developed. The steering Committee accepted my recommendations for the three cost allocation principles and the customer charges for GRS and GSS stated above.

I also asked LUMA management whether they agreed to keep the customer charge for the NEM customers at the same level as the GRS or raise it because the COSS study indicated that they are paying far below what the COSS says they should be paying, but LUMA management indicated that they should pay the same charge.

The steering committee consists of Alejandro Figueroa, Andrew Smith, and Jessica Laird.

- b. Confirmed. The principles that I proposed and that the steering committee accepted provide limits to the revenue allocation and rate design but are broad enough to allow flexibility in how the rates are actually developed.
- c. I relied on my judgement and over 12 years of experience developing rates in rate cases to guide my approach in this matter. Operating with the limiting principles in mind, I developed a rate design that I believe would be just and reasonable, and likely to be adopted by the Puerto Rico Energy Bureau (PREB). In doing so, I considered how the proposed increases would impact

customers, anticipated potential objections from other parties regarding fairness, incorporated prior policy decisions made by the PREB, and aimed to enhance PREPA's revenue stability through the proposed rates.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_All-12.1

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Original Question:

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q32 (page 14).

Preamble: Mr. Shannon's testimony explains that "[f]or customer-classified costs, I used a weighted customer allocator. A straight customer allocator uses the number of customers in each customer class as the basis of the allocation. However, this does not take into account the fact that large commercial and industrial customers often require more resources from the utility because they have more complex bills, often have dedicated account managers, and require larger connections to the distribution network due to their size. To compensate for this, the weighted customer allocator assigns different weights to customer counts, with residential customers as the base customer." (Q32, page 14).

Question(s):

- a) Please explain how the customer weightings for each rate class were determined, including data sources and calculations.
- b) Please provide the following information for each rate class:
 - a. Average interconnection cost per customer
 - b. Average meter cost per customer
 - c. Average administrative costs per customer (i.e. meter reading, billing, etc.)

Rate Review

Follow-up:

Thank you for providing the interconnection and meter cost per customer for part b. Please also provide the same information for either the GRS customer class or all residential customer classes combined.

RESPONDER

Kevin Burgemeister

RESPONSE TO FOLLOW UP REQUEST

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Please refer to Table 12-1 below, which shows the average cost for existing interconnections that do not require structural changes, and the average meter cost for all residential customer classes combined.

Table 12-1 Commercial & Residential Customer Profile

Customer Classification	Rates Class		Voltage	Average Interconnection Cost	Average Meter Cost
Residential	RH3 103 RH3 104 RFR 105 RFR 106 GRS 112	RFR 107 LRS 109 LRS 110 GRS 111	Single-phase or three-phase; 120, 208, or 240 volts	\$950.00	\$150.00

As stated in PC-of-LUMA-COST_ALL-12, LUMA provides average interconnection cost(s) with the understanding that each interconnection is assessed and quoted according to its technical and construction conditions.

Attestation

I, Kevin Burgemeister, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Kevin Burgemeister

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-7.1

SUBJECT

Permanent Rates – Rate Design

REQUEST

Original Question:

Reference: LUMA Schedules O-2 and O-3 and LUMA Ex. 20.0 (7.03.25) Sam Shannon's Expert Testimony Q82 through Q85 (pages 32-33).

Preamble: Mr. Shannon's testimony proposes that "the CILT and SUBA riders recover the total amount for each tariff rate via a fixed monthly charge" (Q82, page 32) but Schedule O-3 shows CILT and SUBA as a \$/kWh rate. In addition, the calculations in the "Rate Inputs" and "Bill Impact" sheets of the "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks show these riders as a \$/kWh rate.

Question(s):

- a) Please confirm if LUMA is proposing to recover the CILT and SUBA riders via a fixed monthly charge.
- b) If (a) is confirmed, please provide versions of all impacted schedules, including O-1 through O-3 and M-4 through M-8, reflecting this proposal.
- c) If (a) is not confirmed, please explain why Sam Shannon's testimony, Q82 through Q85, proposes collecting CILT and SUBA riders via a fixed charge but this is not reflected in any of the schedules.

Followup:

Thank you for your response.

In part b, the answer states "...there would be no difference to how customer classes pay for these riders and therefore there is no need to update these schedules." However, there would be bill impacts to individual customers within each rate class if the CILT and SUBA are charged with a fixed monthly charge instead of an energy charge. In order to evaluate the proposed change, please provide a summary of the CILT and SUBA charge for each rate class and updated schedules M-7 and M-8 for FY2027 and FY2028.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

We acknowledge that the final approved revenue requirement will change, as explained in the response to part c, but the Energy Bureau's consultants are working to evaluate proposed changes to rate design based on the information available at this time.

RESPONSE

Please refer to Attachment to PC-LUMA-RATES-7.1.

The attachment shows how revenue collection within the GRS, LRS, and GSS tariffs would differ between a volumetric energy rate and a fixed monthly rate. The revenue spread by consumption bin could be applied to an illustrative amount to show how customers at varying consumption levels would be affected by converting an energy charge to a fixed charge.

The table below shows, as an illustration, what the current GRS rates for CILT, SUBA-HH, and SUBA-NHH would be for FY2026 if the Energy Bureau had set them as fixed charges using the method described in my testimony.

Rider	Current FY2026 Rate	Fixed Rate Alternative (GRS)
CILT	\$0.004417/kWh	\$1.78/month
SUBA-HH	\$0.012558/kWh	\$5.07/month
SUBA-NHH	\$0.001091/kWh	\$0.44/month

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-8.1

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Please explain how plants were categorized as either peakers or baseload generation. Please include details of how heat rates and capacity factors of plants were considered, if at all, when categorizing plants as peakers or baseload generation.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

For cost allocation purposes, plants were categorized as either peakers or baseload generation based on the descriptions used in Genera's revenue requirement. Questions asking for more detailed information regarding the nomenclature of generation plants should be directed to Genera.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-12.1

SUBJECT

Permanent Rates – Rate Design

REQUEST

In Attachment 1 of the response, the Max Demand and Demand values (columns K through N) of the JUL sheet appear to be taken directly from 2024 historical data. Please confirm that the forecast demand billing determinants for FY2026 through FY2028 use the historical 2024 values. If not confirmed, please explain how the forecast demand billing determinants for FY2026 through FY2028 were calculated.

Please explain how the demand determinants (used in the COSS) are derived for rate classes which are not billed based on any demand determinants? Please provide sources and explanations for the hard coded values in rows 12, 28, and 39 (labelled “Customer Maximum Demand”, “Gross System Peak”, and “Gross Production Coincident Peak”) of the “Allocators” sheet in LUMA - Rate Design Schedules FY2026 (07.03.25).xlsx workbook.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Confirmed, the demand allocators are based on the most recent historic information from the load research sample. The coincident and non-coincident peak demand numbers for customer classes that do not have billed demand units are derived from the LUMA's load research sample.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST-ALL-7

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q20 (page 9).

Preamble: Mr. Shannon's testimony explains that "...I used a modified average-excess calculation to determine the demand/energy split used for some production costs. Under this calculation, the peak PREPA system load is divided by the sum of the peak load and the average monthly load to calculate the proportion of demand-classified production costs. This formula is designed so that for a utility with a 100 percent load factor, the demand/energy split is 50-50. For the test years, the formula results in a 52.3 percent demand share and a 47.7 percent energy share."

The calculations provided in cell E44:E45 of the Minimum Sys sheet of "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks calculate the classification factor as the sum of monthly coincident peak loads divided by the sum of monthly coincident peak loads and the system peak load.

Questions:

- a) Please provide a reference to the page number and table number (if applicable) for the NARUC manual upon which LUMA is basing its classification method.
- b) Please explain what modification is being referred to in the statement "I used a modified average-excess calculation..." (emphasis added).
- c) Please explain why Mr. Shannon chose to calculate average demand as the sum of the monthly coincident peak loads.
- d) Please confirm that the NARUC manual uses the term "average demand" to refer to total energy consumption divided by number of hours. Please also confirm that there are no methods described in the NARUC manual that calculate "average demand" as the sum of monthly coincident peak demands.
- e) Please confirm that when "average demand" (as stated in Mr. Shannon's testimony) is calculated as the sum of monthly coincident peak demands (as shown in the workbooks), that the load factor would not have any impact on determining the classification factors.

Rate Review

f) Please confirm that the utility's load factor would not have any direct impact on the classification factor calculated in the workbooks, which is based on monthly coincident peak demand and annual peak demand only, and that this is inconsistent with the statement that "This formula is designed so that for a utility with a 100 percent load factor, the demand/energy split is 50-50".

RESPONSE

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. See Chapter 4, including the tables.
- b. I did not have data by customer class and thus, I used the system data. See schedule K-1 for the calculation.
- c. The premise of the question is incorrect. I did not use the sum of the monthly coincident peak loads. I used the average system peak. As to why, the theory behind an average/excess calculation is that a utility would build more capital-intensive generation to supply cheap energy to meet the average system loads, but constructs cheaper generators to run less frequently to supply peak loads. As a result, the average demand portion of the average/excess calculation is classified as energy to reflect the lower operating costs of this plant.
- d. The NARUC manual describes different variances of the peak and average demand method that the analyst in his/her discretion may adopt. My testimony explains a modified average demand method which I used in part based on the lack of customer class data.
- e. I do not use the term "average demand" in my testimony. The modified average/excess method is designed to translate the sharpness of the slope of the load curve into an energy-demand split for production plan.
- f. The first question is incorrect. As described above, the sharpness of the slope of the load curve is the characteristic used as the basis for the demand-energy split. While the term load factor in its strictest definition is a function of all hours, it describes in a broad sense the sharpness of the slope of the load curve.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-8

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q20 (page 9).

Preamble: Mr. Shannon's testimony explains that "Genera's capital costs had sufficient breakout to classify the peaker plant costs to demand and the remainder to energy" and further that "The HydroCo costs are classified as all energy." (Q20, page 12)

The allocation of production capital costs is shown in cells C268:T284 of the Cost Allocation sheet of "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks.

The total capital costs that are allocated are taken from Schedule D-1, row 13 – 30, column G.

Questions:

a) For all plants listed in Schedule D-1, rows 13 – 28, please provide the following information in the form of table. Within this table, please breakout individual peaker plants that are included in "Peakers" (row 24) and other plants included in the "Misc Plant Decommissioning" (row 13).

- i. Nameplate capacity
- ii. Fuel type
- iii. Heat rate
- iv. Capacity factor in previous year of operation
- v. Installed cost per MW of nameplate capacity
- vi. Depreciated cost per MW of nameplate capacity
- vii. Installation year
- viii. % of useful life

b) For each of HydroCo's hydro facilities for which capacity costs have been included in Schedule D-1, row 30, please provide the following information in the form of table.

- i. Nameplate capacity
- ii. Storage (reservoir) capacity
- iii. Capacity factor in previous year of operation
- iv. Installed cost per MW of nameplate capacity

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- v. Depreciated cost per MW of nameplate capacity
- vi. Installation year
- vii. % of useful life

RESPONDER

Kevin Burgemeister

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

PC-of-LUMA-Cost-All_8_Attachment 1 includes the following information:

- Name plate capacity
- Fuel type
- Heat rate (as of 10 years ago, with some estimated adjustments we have made since then)
- Capacity Factor
- Installation year

LUMA does not have the other items requested.

Attestation

I, Kevin Burgemeister, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Kevin Burgemeister

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-10

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q22 (page 10).

Preamble: Mr. Shannon's testimony explains that "Distribution poles, conductors, and line transformers are classified according to the customer/demand split to reflect the dual nature of the distribution network." (Q22, page 10).

On the Cost Allocation sheet of "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks, the only distribution O&M costs classified as Customer-related with the customer/demand split are Materials & Supplies (row 41, 42) and Vegetation Management (row 166 – 169). In addition, no distribution capital expenses (rows 267 – 284) as classified to customer with the customer/demand split.

Question(s):

- a) Please confirm that the only distribution expenses classified as Customer-related with the customer/demand split are Materials & Supplies and Vegetation Management O&M costs.
- b) Please confirm that all distribution O&M expenses other than Materials & Supplies and Vegetation Management and all distribution capital expenses have not been classified as Customer-related with the customer/demand split.
- c) Please explain why no distribution O&M expenses other than Materials & Supplies and Vegetation Management and no distribution capital expenses have been classified as Customer-related with the customer/demand split. Please clarify why Mr. Shannon's response to Q22 indicates otherwise.

RESPONDER

Sam Shannon

Rate Review

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. Confirmed.
- b. Confirmed.
- c. I do not agree that my response to question 22 indicates that all distribution O&M expenses other than materials and supplies and vegetation management and no capital expenses have been classified as customer-related with the customer/demand split. The Puerto Rico Electric Power Authority (PREPA) does not have Federal Energy Regulatory Commission (FERC) accounting set up for operation and maintenance (O&M) costs and lacks accurate opening balance information for plant due to the ongoing balance sheet remediation effort, which is an externally managed initiative to which LUMA has no input or influence. The cost accounts used for the customer/demand split represent the best estimate of where the traditional FERC account-based costs would be contained.

Under normal depreciation-based ratemaking, only the depreciation expense would be classified with a customer/demand split. Given the cash-financed nature of PREPA at this time, Mr. Shannon chose to exclude the capital spend from the customer/demand split to avoid over-classifying customer-related costs.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-11

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q32 (page 14).

Preamble: Mr. Shannon's testimony explains that "I conducted a minimum system study. While the plant balances are estimates based off of the information available in Schedule C-7, the results of the minimum system study fell within what I considered to be the range of reasonableness." (Q23, page 11).

The calculations provided in rows 7 – 20 of the Minimum Sys sheet of "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks outline the calculations for the minimum system study.

Questions:

a) Please provide detailed calculations showing how the "Plant Balance (estimate)" values in cells D14:D16 of the Minimum Sys sheet were derived from the information available in Schedule C-7.

a) Please explain how the minimum items for conductors, distribution poles and line transformers were chosen and explain how the unit cost and total asset count values were derived for each of these components.

c) Please define what Mr. Shannon considers to be the "range of reasonableness" of the minimum system study results. Please explain what Mr. Shannon would consider outside of the "range of reasonableness".

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Rate Review

- a. The Plant balance numbers are the sum of company 003 (LUMA post-commencement) and company 001 (PREPA pre-commencement). The details of company 001 balances come from the 2019 audited account balances shown in Appendix A of the attached document. The table below shows the discrete components.

Plant Type	Company 001 Balance (2019)	Company 003 Balance	Total
Conductors	\$1,031,962,291	\$53,293,601	\$1,085,255,892
Dist. Poles	\$507,625,839	\$74,687,420	\$582,313,259
Line Transformers	\$451,457,185	\$29,917,913	\$481,375,098

- b. This information was provided to Mr. Shannon by LUMA distribution asset management staff.
- c. The first-order reasonableness evaluation is that customer-classified costs should be a non-zero value. In Mr. Shannon's experience, the percentage of customer-classified costs in a minimum system study depends on the age of the infrastructure and the installed cost. For customer-classified costs, a range between 20 and 70 percent would be within expected values.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-12

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q32 (page 14).

Preamble: Mr. Shannon's testimony explains that "[f]or customer-classified costs, I used a weighted customer allocator. A straight customer allocator uses the number of customers in each customer class as the basis of the allocation. However, this does not take into account the fact that large commercial and industrial customers often require more resources from the utility because they have more complex bills, often have dedicated account managers, and require larger connections to the distribution network due to their size. To compensate for this, the weighted customer allocator assigns different weights to customer counts, with residential customers as the base customer." (Q32, page 14).

Question(s):

- a) Please explain how the customer weightings for each rate class were determined, including data sources and calculations.
- b) Please provide the following information for each rate class:
 - a. Average interconnection cost per customer
 - b. Average meter cost per customer
 - c. Average administrative costs per customer (i.e., meter reading, billing, etc.)

RESPONDER

Sam Shannon and Kevin Burgemeister

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Rate Review

a) **Sam Shannon:** The customer weightings used by Mr. Shannon are based on his experience and professional judgement.

b) **Kevin Burgemeister:**

a-b. Average interconnection cost per customer and average meter cost per customer

There are multiple predefined variables that affect interconnection costs. One variable is project type because each connection point differs in design level, available load capacity, and technical requirements. Other variables include whether the installation is underground or overhead, the connection voltage, and each customer's specific specifications (especially for loads under 50 kVA or industrial customers). Given this variability, LUMA submits there is no predetermined fixed cost, and a single average interconnection cost across all customer classes would not reflect reality. Instead, LUMA provides average interconnection cost(s) for customer classes other than residential and subsidized rates with the understanding that each interconnection is assessed and quoted according to its technical and construction conditions. To answer part b. of the request, meter costs are also included.

The table below shows the approximate operational cost(s) for an existing interconnection point that does not require structural changes, and the meter cost.

RATE	LOAD	VOLTAGE	AUXILIARY EQUIPMENT	AVERAGE INTERCONNECTION COST	AVERAGE METER COST
GSS	Under 50 KVA	Single-phase or three-phase; 120, 208, 240 or 440 volts	N/A	\$1,500.00	\$ 150.00
GSP	Equal or greater than 50 KVA	Three-phase; 2,300; 4,160; 8,320; 13,200 volts or other primary distribution voltage	CT & PT	\$1,500 Aerial / \$2,350 Underground	\$ 525.00
GST	250 kVA or greater	Three-phase; 38 or 115 kV	CT & PT	\$1,500.00	\$ 525.00
TOU-P	1,000 kVA or greater	Three-phase, 2,300, 4,160, 8,320, 13,200 volts or other primary distribution voltage	CT & PT	\$1,500.00	\$ 525.00
TOU-T	1,000 kVA or greater	Three-phase; 38 or 115 kV	CT & PT	\$1,500.00	\$ 555.00
LIS	Equal to or greater than 12,000 kW, a load factor equal to or greater than 80% and a monthly average power factor of 95% or more.	Three-phase, three or four wires, 115 kV.	CT & PT	\$1,500.00	\$ 555.00

In spite of the foregoing, key elements that could increase or alter the interconnection cost include, but are not limited to:

- Construction work involved
- Easement clearing or access opening
- Pole replacement or modification
- Complexity of the required maneuvers

c. Average administrative costs per customer (i.e. meter reading, billing, etc.)

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

LUMA does not have an estimate of billing costs per customer. However, based on annual meter reading data, LUMA provides the following meter reading cost per customer estimates:

METER READING	COST	NOTES
MANUAL	Annual \$239,389.92 Per customer \$11.70	Manually reading around 20,000 meters
REMOTE	Annual \$1,200,000.00 Per customer \$0.92	Remotely reading around 1.3 million meters.

LUMA notes that meter reading costs are only a portion of the administrative costs tied directly to customers, and that the costs described above are only a partial depiction of the average administrative cost per customer.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

I, Kevin Burgemeister, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Kevin Burgemeister

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-5

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q58 (page 25).

Preamble: Mr. Shannon's testimony explains that "The Utility's proposed rate design increases the customer charge for residential customers year-over-year up to \$20.00 per month by the 2028 test year. This will bring the customer charge in line with the total amount of customer-classified costs."

The customer charges for GRS and GSS are calculated on the Functional Costs sheet of the "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks. The Distribution Capital Expense (cells J26 and S26) calculation multiplies the sum of the Distribution, Control Center & Buildings, and Enabling capital expenses allocated to the rate class by the customer/demand split calculated from the minimum system study.

Questions:

- a) Please explain why the customer charge calculation includes a portion of the Distribution, Control Center & Buildings, and Enabling capital expenses (based on the customer/demand split) while in the COSS, these costs have been classified based on either NCP demand or energy (cells T297:T323 of the Cost Allocation sheet), with no classification to customer.
- b) Please explain why the customer charge calculation includes the Excess Expenditures cost (row 187 of the Cost Allocation sheet) while in the COSS, this cost was classified and allocated based on energy.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- a. Cost classification and cost allocation are two separate (but often related) activities. As discussed in the response to *PC-of-LUMA-COSTALL-10 (c)*, the cash-financed nature of PREPA requires some deviation from normal practice in how a utility's capital costs are allocated to customer classes. Even if the distribution capital costs are not allocated in a traditional manner, it is unreasonable to assume that the capital costs for the distribution system are 100 percent demand-classified.
- b. I disagree with the assertion that cost classification and cost allocation are the same thing. The Excess Expenditure revenue requirement item does not fit neatly into traditional cost functionalization and classification. Therefore, Mr. Shannon used his judgement to assign those costs to the customer functional cost area.

ATTESTATION

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-6

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: LUMA Schedule M-2 and “LUMA Schedules M-2, M-5, N-1, N-2, N-3 (7.03.25).xlsx”

Preamble: Resolution and Order issued May 29, 2025 defined "Proposed Rates with Existing Rate Design" refers to rates based on the proposed budget (Constrained or Optimal) and proposed revenue allocation, but with the existing rate design". Schedule M-2 subsequently requested a “comparison of Proposed Rates with New Rate Design design) to Proposed Rates with Existing Rate Design. For both Proposed Rates with New Rate Design and Proposed Rates with Existing Rate Design, provide these rates for both the Rate Year and Extension Years and for both Optimal and Constrained Budgets. Provide all rate components, including riders that would be included in the customer bill. Summarize all proposed changes and provide rationales for those changes.”

It is unclear how the Proposed Rates with Existing Rate Design have been calculated and if they are suitable to be used as a baseline from which to compare the proposed rate design changes.

Questions:

a) Please provide a detailed explanation of how the Proposed Rates with Existing Rate Design in Schedule M-2 have been calculated.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- a. The proposed rates with existing rate design in schedule M-2 were calculated to maintain the revenue ratio collected under the current rates for each customer class from the various billing components (fixed, demand, energy, etc.).

ATTESTATION

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-7

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: LUMA Schedules O-2 and O-3 and LUMA Ex. 20.0 (7.03.25) Sam Shannon's Expert Testimony Q82 through Q85 (pages 32-33).

Preamble: Mr. Shannon's testimony proposes that "the CILT and SUBA riders recover the total amount for each tariff rate via a fixed monthly charge" (Q82, page 32) but Schedule O-3 shows CILT and SUBA as a \$/kWh rate. In addition, the calculations in the "Rate Inputs" and "Bill Impact" sheets of the "LUMA - Rate Design Schedules FY2026 [2027, 2028] (7.03.25).xlsx" workbooks show these riders an a \$/kWh rate.

Question(s):

- a) Please confirm if LUMA is proposing to recover the CILT and SUBA riders via a fixed monthly charge.
- b) If (a) is confirmed, please provide versions of all impacted schedules, including O-1 through O-3 and M-4 through M-8, reflecting this proposal.
- c) If (a) is not confirmed, please explain why Sam Shannon's testimony, Q82 through Q85, proposes collecting CILT and SUBA riders via a fixed charge but this is not reflected in any of the schedules.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. Confirmed.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- b. The change in recovery of CILT and SUBA, if approved by the Energy Bureau, would not take effect until FY2027. The proposed tariff sheets are for FY2026 only. Contributions in Lieu of Taxes (CILT) and SUBA (Subsidies HH related to Help to Humans and NHH related to Non-Help to Humans Subsidy) are represented by a pro forma revenue requirement amount and energy rate. The proposal to convert CILT/SUBA to fixed charges would maintain the status quo class allocation by energy, so there would be no difference to how customer classes pay for these riders and therefore there is no need to update these schedules,
- c. Both CILT and SUBA use annual reconciliations to recover under/over-collected amounts in the prior fiscal year. For FY2027, the reconciliation will be heavily impacted by the revenue requirement ultimately approved by the Energy Bureau, the removal of low-income subsidies from needing to be part of the calculation as they have been embedded in base rates, and the provisional rate true-up. Therefore, attempting to estimate the bill impacts within a customer class given the uncertainty created by these changes is not recommended at this time. This is the reason for using pro forma numbers. LUMA will provide estimated bill impacts for the fixed charge, if approved, in May 2026 for the FY2027 rider filings.

ATTESTATION

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-RATE_DES-8

SUBJECT

Permanent Rates – Rate Design

REQUEST

Reference: LUMA Schedule O-2 and LUMA Ex. 20.0 (7.03.25) Sam Shannon's Expert Testimony Q.91 (page 36).

Preamble: Schedule O-2 specifies that the CILTA, SUBA-HH, and SUBA-NHH “shall apply to all energy delivered to customers...”(pages 40 – 44), but also that the applicable retail kWh sales are “energy sales to all classes of customers, including the net inflow (i.e. inflow – outflow) to all net metering customers”(page 45) (emphasis added).

In addition, Schedule O-2 specifies that for the Net Metering Credit Rider:

“Each billing period, in which the energy exported by the customer is lower than the energy supplied by PREPA, the credit for the energy exported shall be the sum of: customer’s base rate energy charge, fuel energy charge, purchased power energy charge, SUBA-HH energy charge, SUBA-NHH energy charge, CILT energy charge, and Energy Efficiency Charge.”

Mr. Shannon’s testimony in answer to Q.91 explains that “proposed changes [to the Net Metering Rider] specifically identify which riders are non-bypassable, which means that the customer cannot escape the charge though other credits.”

Question(s):

- a. Please provide a detailed description of what is meant by “energy delivered to customers” in CILTA, SUBA-HH, and SUBA-NHH schedules.
- b. Please explain whether LUMA is proposing to change the definitions of the “applicable retail kWh sales” in each of the CILTA, SUBA-HH, and SUBA-NHH schedules as well as the specification of the charges in the Net Metering Credit Rider. The definitions provided for these charges appear to contradict both the “energy delivered to customers” specified in each rider, as well as the statement in Mr. Shannon’s testimony that “proposed changes [to the Net Metering Rider] specifically identify which riders are non-bypassable.”

RESPONDER

Rate Review

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. Energy delivered is all energy provided to the customer, whether metered or not.
- b. No, there are no proposed changes to “applicable retail kWh sales” or charges in the Net Metering Rider. Proposed changes for clarification on the CILT and SUBA tariffs and Net Metering are independent of each other. For FY2026, the CILT and SUBA tariffs have already been authorized by the Energy Bureau in the permanent rate docket, so the proposed tariffs are reflective of the status quo. LUMA’s proposal to convert CILT and SUBA to fixed charges in FY2027 would remove the fixed charges from the list of credits applied to exported energy. If changes are approved by the PREB, LUMA will file updated CILT and SUBA tariff sheets consistent with the authorized changes in the standard rider updates in May 2026.

ATTESTATION

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-REV_All-1

SUBJECT

Permanent Rates – Revenue

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx, Sam Shannon's Expert Testimony Q43 (page 18),

Preamble: Please see Table 4, 5, and 6 of Mr. Shannon's testimony. See also cell H43 of the Revenue Summary w Rider sheet of LUMA - Rate Design Schedules FY2026.xlsx.

Question(s):

- a) Please explain why the Total Utility COSS Increase does not match the Proposed Revenue Increase in Tables 4, 5, and 6.
- b) Please explain why summing the Proposed Revenue Increase for each rate class does not match the Total Utility value in Table 4.
- c) Please explain why the Total Utility Proposed Revenue Increase in Table 4 does not match the value in cell H43 of the Revenue Summary w Riders sheet of LUMA - Rate Design Schedules FY2026.xlsx.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. I disagree with the assumption that the proposed increase does not match the revenue deficiency. The overall increase to the utility in FY2026 is 36.40 percent, which matches the deficiency from the cost of service study (COSS) of 36.40 percent. The percentage increases for the other two test years also match the COSS deficiency percentages. Deviations beyond a hundredth of a percent are considered de minimis.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- b. The total utility number in that table is a typo. The correct number should be \$1,432,887,326.
- c. See the response to part b.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-REV_ALL-2

SUBJECT

Permanent Rates – Revenue

REQUEST

Reference: Sam Shannon's Expert Testimony Q44 (page 22).

Preamble: As stated in Mr. Shannon's testimony: "The revenue allocations attempted to balance three goals. First, given the size of the overall increase requested in the rate case, no customer class should receive a decrease from present rates. Second, low-income residential customers' increase should be capped at a maximum of 30 percent. Finally, no class should receive an increase greater than two times the overall utility percentage increase." (Q44, page 22)

Question(s):

- a) Please explain how Mr. Shannon decided upon the three goals of the revenue allocation.
- b) Please provide any precedents, with sources, of the three principles used by Mr. Shannon to determine the revenue allocation.
- c) Please explain in detail how these principles were used to determine the final revenue allocation, providing calculations where available.

RESPONDER

Sam Shannon

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. The goals described by Mr. Shannon reflect rate design principles of gradualism and maintaining an embedded discount for low-income residential customers. Gradualism attempts to minimize rate shock by moderating increases to customers, where appropriate. It is currently the policy of the Energy Bureau that the low-income residential classes receive an embedded discount in the form of lower rates than the base General Residential Service (GRS) rates.

Rate Review

- b. Gradualism is an industry-standard policy objective, reflected in Bonbright's rate design principle number five: "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers." The discount for the non-Residential low-income classes was reiterated in the 2017 rate order from the Energy Bureau as a matter of policy for the Commonwealth.
- c. Mr. Shannon set rates using his best judgement to achieve a revenue allocation that adhered to the goals described above. The goals provided guiderails and limitations in how the revenue requirement would be collected from the customer classes.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/Sam Shannon

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-COST_ALL-6

SUBJECT

Permanent Rates – Cost Allocation

REQUEST

Reference: LUMA - Rate Design Schedules FY2026.xlsx; Sam Shannon's Expert Testimony Q15 (page 7)

Preamble: Mr. Shannon's testimony explained "LUMA does not separate out its expenses by transmission or distribution, so I applied the share of miles of lines for each to perform a rudimentary splitting of the GridCo costs into transmission and distribution. Miles of transmission and distribution lines is a rough proxy for the level of investment needed in each functional area." (Q15, page 10).

LUMA's Rate Design Schedules spreadsheet shows that this transmission/distribution split is applied to Operations and Maintenance Expense and that transmission is given a weight of 3, indicating that transmission costs are 3x more expensive than distribution costs.

Question(s):

- a) Please confirm E3's understanding from the Excel spreadsheets that transmission is assumed to cost 3x more per mile than distribution when used to allocate Operations and Maintenance costs.
- b) If (a) is confirmed, please explain which expenses are allocated based on "the share of miles of lines" (without the 3x factor), as stated in Mr. Shannon's testimony.
- c) If (a) is confirmed, please explain how the transmission weighting factor of 3 is derived, including data sources and calculations.
- d) Please provide average historical installation costs/mile for transmission lines and distribution lines.

Rate Review

RESPONDER

Sam Shannon and Pedro Meléndez

RESPONSE

LUMA files this discovery response without in any way implying that it considers the information requested could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a) **Sam Shannon:** Correct.
- b) **Sam Shannon:** The transmission and distribution (T&D) expenses are not allocated to customers based on miles of line. The miles of line estimate is used to split the Operations and Utility Transformation cost categories from LUMA into transmission and distribution functional costs areas.
- c) **Sam Shannon:** There are no supporting calculations for the 3x cost adder; it is a reasonable estimate based on Mr. Shannon's judgement.
- d) **Pedro Meléndez:** LUMA does not have historical actuals to provide an average cost per mile for transmission and distribution line rebuild activity because the first transmission and distribution line rebuild projects for LUMA are anticipated to receive federal funding obligation and commence this Fiscal Year. However, LUMA has planning level estimates in Table 5 of Pedro Melendez's testimony and the bases for those estimates are described in Table 6. Specifically, PBUT33 Transmission Line Rebuild and PBUT6 Distribution Line Rebuild.¹

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

I, Pedro Meléndez, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Pedro Meléndez

¹ See LUMA Ex. 5.0 Direct Testimony of Pedro A. Meléndez Meléndez – Capital Programs and Grid Transformation, ps. 44-46

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-6

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: Joseline N. Estrada-Rivera Testimony, page 8, Q.24

Preamble: Ms. Estrada-Rivera's testimony states: "Historical monthly CDD [Cooling Degree Day] data from NOAA's National Weather Service was used to estimate regression. Guidehouse developed several forecast scenarios based on different percentiles of increase, using the median of the observed monthly CDD. In a previous update used for the 2025 approved PREPA's Fiscal Plan and 2025 operational budget, we applied a 50th percentile increase for both the residential and commercial models. However, due to the recent rise in observed CDDs and their impact on residential load, we selected the 73rd percentile for the residential model through 2028. The commercial model, on the other hand, continues with the typical 50th percentile scenario."

Questions:

- a. Please provide additional clarification for why a different percentile is used for CDDs for the residential sector versus the commercial sector.
- b. Please provide additional clarification for how the 73rd percentile for the residential model was selected.

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

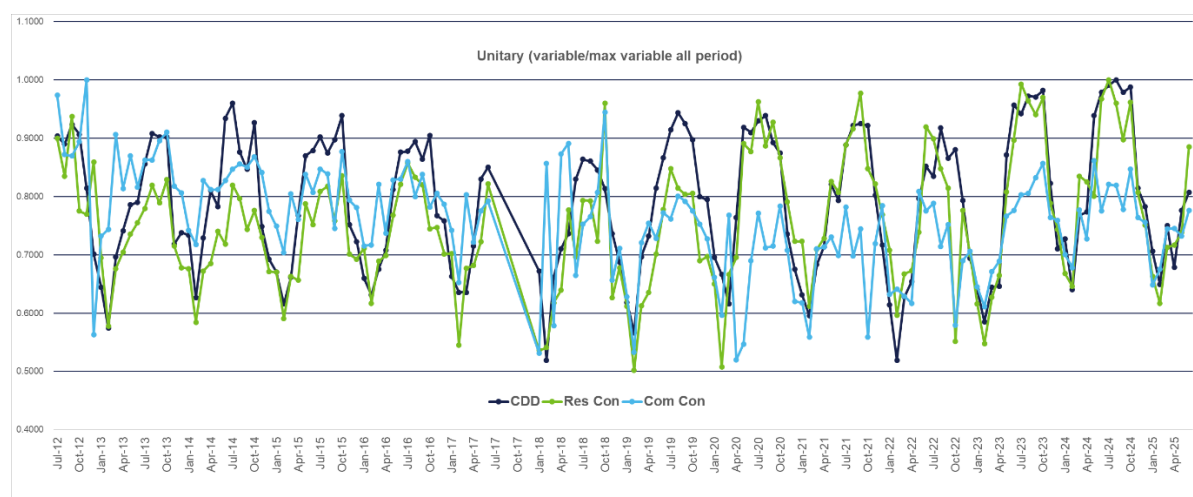
LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. The warmer weather in the past two fiscal years has affected residential consumption more than commercial consumption. Following fiscal year 2021, the integration of photovoltaic systems diminished residential consumption; nevertheless, the increase in temperature is causing net

Rate Review

metering photovoltaic customers to raise their self-consumption, thus, these customers are decreasing exports to the grid and relying more on deliveries from the grid. The commercial class does not demonstrate this behavior. To demonstrate this behavior, refer to the figure 6-1 below. Figure 6-1 shows that Cooling Degree Days (CDD), residential and commercial consumption has been normalized to a uniform unit by dividing the monthly variable by the maximum value of each variable over the period from July 2012 to June 2025. The slope throughout this period is positive for CDD and residential consumption, but negative for the commercial class. Prior to July 2019, the commercial reflects the same patterns as the CDD. Nevertheless, following the historical rise in CDD, which peaked in August 2024, commercial consumption demonstrates an even trend. The residential class experiences comparable tendencies, with the Cooling Degree Days reaching a peak in July 2024. However, the commercial sector peaked in November 2012, when the CDD was 19% below the historical peak recorded in July 2024.

Figure 6-1. Residential and Commercial Monthly CDD and Energy Consumption Patterns



During the study period, the longest historical increase in CDD occurred after May 2023.

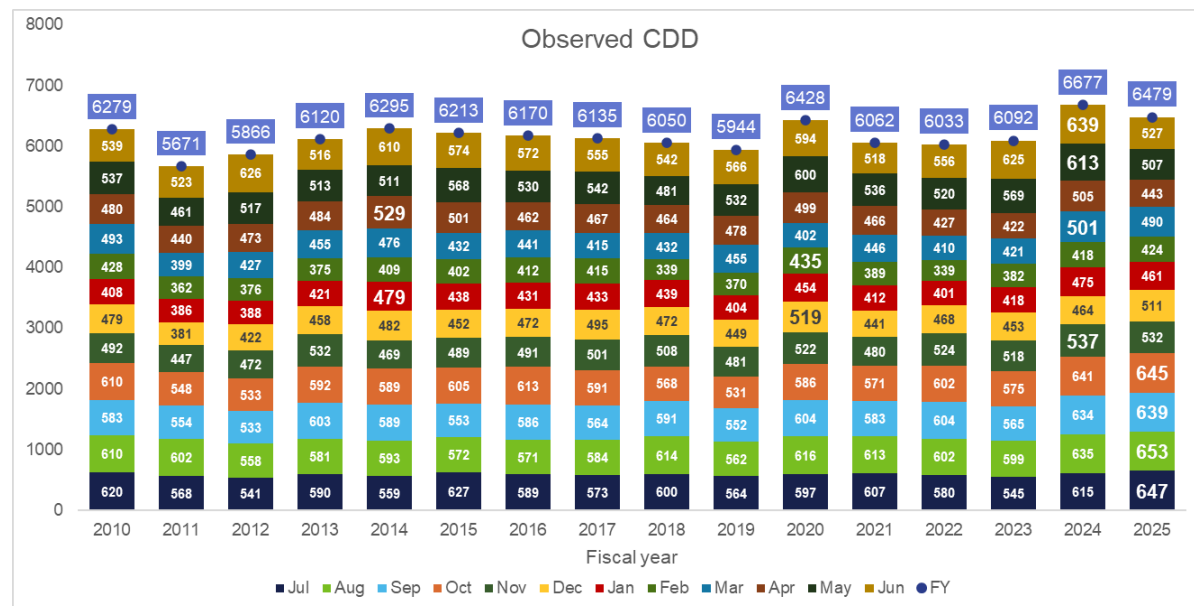
In the eight months of the twelve-month period from FY2010 to FY2025, the peak of CDD occurred between fiscal years 2024 and 2025. Monthly CDD peaks are observed in six consecutive months (May to October 2024). This has never occurred before; in the previous forecast updates, LUMA did not have sufficient data to warrant choosing a higher CDD to forecast any class than the 50 percentiles. However, based on the more recent data, LUMA determined that it was appropriate to use a higher CDD for the residential class and leave the CDD for the commercial model at the 50 percentiles, taking into account the trends after fiscal year 2024, analyzing the figure that illustrates the correlation between the increase in the CDD and the residential class, and, finally, considering the variance between the observed consumption and the forecast in the past two years.

Rate Review

Figure 6-2. FY2024 - FY2025 Residential and Commercial CDD

FY		Residential	Commercial
2024	Forecast	6,166.8	7,072.7
	Actual	7,321.3	8,022.9
	Variance %	18.7	13.4
2025	Forecast	6,371.4	7,762.0
	Actual	7,009.7	7,820.2
	Variance %	10.0	0.7

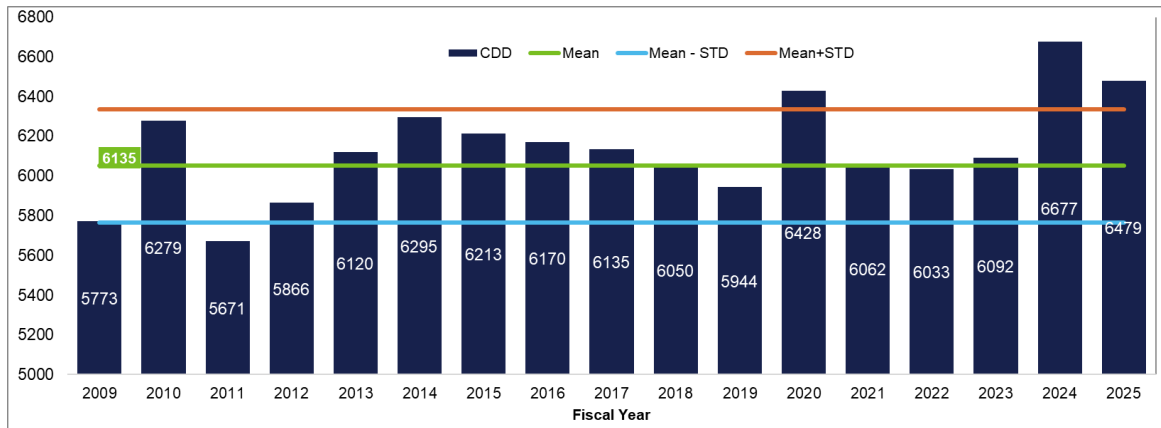
Figure 6-3. FY2010 - FY2025 Observed CDD



- b. When totaled by fiscal year, 2024 and 2025 exhibit higher CDDs, at 6677 °F and 6479 °F, respectively. Figure 6-3 below illustrates the yearly CDD, indicating that the fiscal years 2024 and 2025 exceed the mean of the studied period (6135 °F). Furthermore, the CDD for fiscal years 2024 and 2025 exceed the upper threshold when the standard deviation is added to the mean. The CDD forecast at the 73rd percentile exhibits a variance of 5% relative to the maximum threshold (mean plus standard deviation), a percentage that is identical when comparing the CDD of fiscal year 2024 with this threshold. LUMA examined various CDD percentiles, ultimately selecting the 73rd percentile based on the resulting residential consumption trend.

Rate Review

Figure 6-3. Annual Cooling Degree Days: FY2024–FY2025 Above Historical Mean (6135°F)



Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-9

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update

Preamble: In LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update, the tabs “Residential – 73th percentile”, “Commercial,” and “Industrial” each include historical rate class consumption by month and apply the regression formulas to forecast the base load for each rate class.

On the “Industrial” tab, cell D5 is labeled “Actual Demand (Adj exc CHP displacement)”. This column is set equal to the “Forecast Demand” in column E, which is calculated based on the regression.

On the “Yearly” tab, the values from “Industrial” tab, column D, are summed up for each year to produce the industrial rate class base load forecast.

Questions:

- a. On the “Industrial” tab, why does column D, “Actual Demand (Adj exc CHP displacement),” equal the “Forecast Demand” in column E, if column D is intended to represent actual demand excluding CHP?
- b. Please confirm that historical CHP displacement is not excluded from the base load forecast calculation.
- c. If (b) is confirmed, please confirm that the forecast with load modifiers is therefore double counting the potential impacts of CHP. If the forecast with load modifiers is not double counting the potential impact of CHP, please explain why.
- d. Please confirm that the “Residential – 73th percentile” and “Commercial” tabs do not subtract out DG displacement and DG is therefore not excluded from the base forecast calculation.
- e. If (d) is confirmed, please confirm that the forecast with load modifiers is therefore double counting the potential impacts of DG. If the forecast with load modifiers is not double counting the potential impact of DG, please explain why.

Rate Review

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. The integration of distributed energy, specifically within the industrial class, leads to significant deviations in the typical behavior of this class (see table 9-1 below). Starting in fiscal year 2022, the discrepancy between actual and forecasted consumption is substantial. LUMA modified the forecasting models removing the impact of customers with combined heat and power (CHP) from the endogenous variable (industrial consumption). Accordingly, Guidehouse (GH), a LUMA consultant, developed a consumption backcast modeling to estimate the consumption of the customers identified as having CHP assuming no CHP installation (excluding those who have disconnected from the grid). Column D has the redacted backcast results until February 2025, provided by GH, whereas column E contains the forecasts for the complete period with the formula intact.

Table 9-1. DER Impact on Industrial Load Patterns

FY	Forecast	Actual	Variance %
2020	2,026.94	1,957.85	-3.41
2021	1,959.37	1,876.29	-4.24
2022	2,074.59	1,868.97	-9.91
2023	1,812.90	1,680.20	-7.32
2024	1,864.02	1,641.03	-11.96
2025	1,720.01	1,479.48	-13.98

- b. Not confirmed — historical CHP displacement is *not included* in the base load forecast calculation.
- c. CHP modifier was not double counted, as the base load excludes its impact on the CHP load. The previous industrial forecast model accounted for consumption with the decrease of CHP, so the base industrial load was impacted. Consequently, the incremental amount was added to the base load to avoid duplicate counting. However, as explained in the preceding response, the new industrial model's base load includes consumption prior to the installation of the CHP systems.
- d. The load displacement of net energy metering (NEM) customers is embedded into the observed data used for calculating the coefficients of the exogenous variables that explain each customer class. The base load forecasts include the reductions from customers participating in the NEM program up to the most recent historical month.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

- e. The incremental amount was added to the base load to prevent the displaced load from being double counted, as it is already present in the observed data, as explained in item *d*. The incremental amount is determined by the estimated load displacement from FY2025, as follows:
- Estimated displacement for the fiscal year 2026 minus the estimated displacement for the fiscal year 2025.
 - Estimated displacement for the fiscal year 2027 minus the estimated displacement for the fiscal year 2025.

Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-10

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: LUMA Exhibit 4.03 (7.03.25)- Load Forecast Modifiers FY 2025

Preamble: In LUMA Exhibit 4.03 (7.03.25)- Load Forecast Modifiers FY 2025, the “DG” tab includes historical and forecast data for DG capacity, generation, and number of customers by rate class.

Questions:

- a. How are the DG capacities by customer class (columns H-K) estimated for future years? These are hardcoded values.
- b. Please explain all differences between Bill Customer (MN) in column C and Registered Customer (MN) in column D.

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- a. The capacity values in the forecast are the outputs of a documented and reproducible statistical forecasting process conducted in the R programming language. The values appear static in the Excel file because the spreadsheet is the final reporting artifact, not the calculation environment itself. This modeling approach was chosen over a spreadsheet-based calculation because it provides superior statistical rigor, scalability, and transparency.

Forecasting methodology by customer class:

The forecasting method was tailored to the distinct growth patterns observed in the historical data for each customer class.

Rate Review

- **Residential and commercial classes:** These classes showed clear non-linear growth patterns characteristic. To model this, we used a Gompertz Growth Model. This statistical method analyzes the historical "S-shaped" adoption curve and calculates key parameters to project its future trends. The R code automates this process by fitting the model to the data and then generating the month-by-month capacity forecast based on the statistically derived growth curve.
- **Industrial and agricultural classes:** In contrast, the historical data for these sectors showed that growth had stagnated or plateaued. Applying a dynamic growth model would be inappropriate. Therefore, based on the data, a more direct and defensible assumption was made: their capacity was forecasted to remain constant at the most recently observed maximum.

Transparency and verification:

- The end-to-end process, from data loading, to applying the different models for each customer class, and generating the final table, is encapsulated in the R script.
 - We are committed to full transparency in our methodology. The complete R code and its documentation can be made available for review. This allows anyone to independently examine the logic, verify the process, and replicate the results.
- b. Billed customers under the Net Energy Metering (NEM) program are those who receive a bill that includes their NEM credit, which is the 1:1 credit for the energy they export. In other words, these customers see their net metering credit reflected on their bill. Registered customers, on the other hand, are those who are listed in the net metering portal but have not yet had their NEM rate applied to their bill. This delay can occur for several reasons:
- **Billing cycle:** These customers might be waiting for their current billing cycle to end before the NEM rate is applied to their next bill.
 - **Documentation:** There may be pending documentation required to finalize the application process.
 - **Hardware and inspection:** The customer may be waiting for a meter change or a final inspection of their system.

Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-11

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update

Preamble: In LUMA Exhibit 4.02 (7.03.25)- Load Forecast 2025 Update, the “FP approved Load w Modifiers” tab adjusts the base load forecast by subtracting the DG, CHP, and EE displacement forecasts and adding in the EV consumption forecast. The “Load w Modifiers Peak demand” tab takes the modified base load forecast and calculates the peak demand forecast for each rate class, by applying a load factor to the modified forecast demand in each rate class.

Questions:

a. Please confirm that the calculation of peak demand forecast by rate class does not consider the load shape of any of the load modifiers, and that the load modifiers therefore do not impact the timing of the peak demand forecast relative to the base load forecast.

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Confirmed, the peak demand does not consider the load shape of any of the load modifiers.

Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-LOAD_FOR-12

SUBJECT

Permanent Rates – Load Forecast

REQUEST

Reference: Joseline N. Estrada-Rivera Testimony, page 11, Q.28, Q.34

Preamble: Ms. Estrada-Rivera's testimony states: "This capacity factor was used for the forecast years 2026 to 2028, with a percentage increase applied based on the assumption that these customers may increase their production in their second year of operation."

The testimony also states: "The following chart presents the consumption data for each year up to February 2025, allowing for a comparison with the current year. It illustrates how, over time, industrial load growth has slowed, not only for customers with CHP systems that have been reported to LUMA, but also for regular customers. Analyzing the proportion of both groups within the total, it is notable that customers with CHP represented 35% of total industrial consumption in FY2019. However, by FY2025, this proportion decreased to 29%. This indicates that these customers are having a negative impact on this class."

Questions:

- a. Please provide data and calculations to support the assumption that CHP customers increase their production in the second year of operation.
- b. Please explain why the consumption of non-CHP customers may be decreasing over time. Is the decrease in consumption by non-CHP customers partially or fully due to the installation of CHP by these customers and therefore the exit of customers from the non-CHP customer group?

RESPONDER

Joseline N. Estrada Rivera

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response is relevant or could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

Rate Review

- a. LUMA analyzes the monthly consumption patterns of Combined Heat and Power (CHP) customers to determine the date on which CHP customers begin utilizing their systems after requesting an evaluation for system interconnection. LUMA needs to rely upon this consumption analysis to determine the date when CHP customers began using their system because these customers lack any identifiable information in the billing system, in contrast to net metering customers, who can be identified in the billing system after their tariff is modified to account for exports.

The consumption patterns of these customers are somewhat erratic once they are identified as beginning to use their systems. In some months, their consumption experiences a substantial decrease, while in other months CHP customers exhibit consumption levels similar to their consumption before the CHP system was installed. LUMA prepared a survey distributed to all customers seeking evaluation for interconnection to confirm the size of their systems and their planned operational strategies; however, only two customers responded. Alternative techniques to obtain this data, including meetings, were employed; nonetheless, LUMA also failed to obtain the requested information from these alternative techniques. Given limited information available regarding their operations, we assessed their impact by utilizing monthly billing data concerning consumption.

Table 12-1 below confirms that the customers diminished consumption from the grid in the second year after starting using the CHP systems. Customers that started utilizing the CHP systems for a minimum of 12 months are shown. It has been noted that most customers decreased their consumption more in the second year compared to the first year. It is important to note that the table does not include total usage prior to these customers using their CHPs. Consumption was calculated after identifying the decrease in consumption, leading to the assumption that it resulted from CHP utilization.

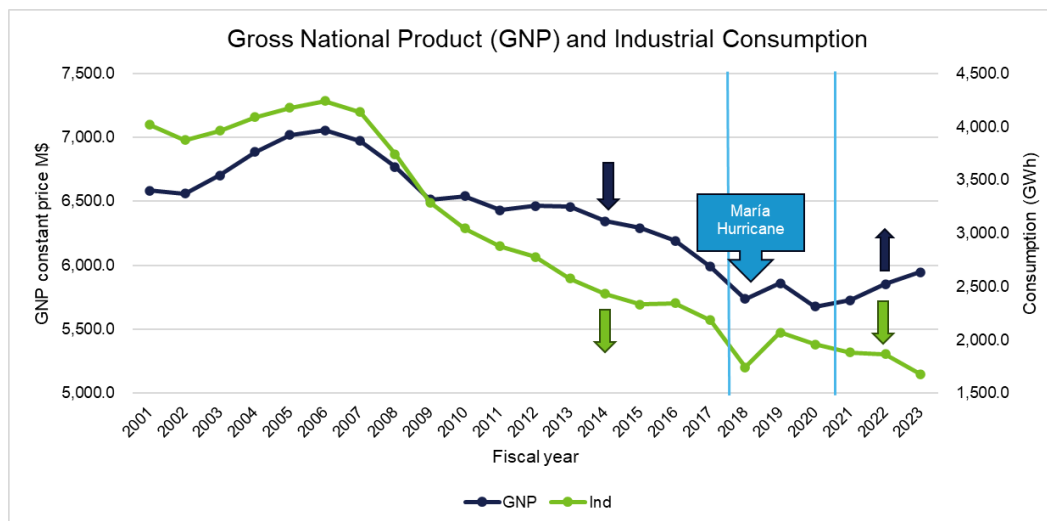
Figure 2-1. Impact of CHP Adoption on Grid Consumption (Year 2)

	1 year	2 year	Variance
Customer 1	7,130,640	991,320	-86%
Customer 2	1,176,677	335,265	-72%
Customer 3	2,326,500	1,366,200	-41%
Customer 4	779,646	759,000	-3%
Customer 5	13,584,120	6,550,236	-52%
Customer 6	125,136	42,570	-66%
Customer 7	1,288,188	957,964	-26%
Customer 8	8,917,920	2,538,360	-72%
Customer 9	6,639,600	6,435,000	-3%
Customer 10	12,173,040	11,099,484	-9%
Customer 11	21,078,684	14,517,360	-31%
Customer 12	2,266,836	1,267,200	-44%
Customer 13	11,144,338	10,926,590	-2%
Customer 14	5,316,960	5,179,200	-3%
Customer 15	106,016,733	77,770,463	-27%

Rate Review

- b. Industrial use had been declining prior to the deployment of the CHP system due to economic factors (refer to the figure 12-2 below). Puerto Rico lost an important industrial incentive at the end of the 1990s, which adversely affected the industrial sector following the fiscal year 2006, marking the onset of the longest recession in Puerto Rico's history. The customer base declined from 2009 to 2017 by approximately 275, reflecting an annual average decrease of -4%, while consumption fell by 1,100 GWh, averaging -5% each year. Distributed generation, an additional driver, is influencing the industrial load after fiscal year 2020. The figure below illustrates the increase in gross national product (GNP) against the continuing decline in industrial consumption.

Figure 2-2. Gross National Product (GNP) and Industrial Consumption



Attestation

I, Joseline N. Estrada Rivera, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Joseline N. Estrada Rivera

**COMMONWEALTH OF PUERTO RICO
PUERTO RICO ENERGY COMMISSION**

IN RE: REVIEW OF RATES OF THE
PUERTO RICO ELECTRIC POWER
AUTHORITY

MATTER NO.: NEPR-AP-2023-0003

SUBJECT: EXPERT REPORT: PREPA
BACKGROUND, REVENUE
REQUIREMENT, FUEL AND PURCHASE
POWER ADJUSTORS, SUBSIDIES AND
CILT ADJUSTORS, UNCOLLECTIBLES,
MAJOR STORM RIDER

EXPERT REPORT

OF

**Ralph C. Smith
&
Mark S. Dady**

**Larkin & Associates PLLC
15428 Farmington Road
Livonia, MI 48154
734-522-3420**

October 6, 2025

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LIST OF EXHIBITS

- PC Ex. 62.01 Qualifications of Ralph C. Smith
- PC Ex. 62.02 Qualifications of Mark S. Dady
- PC Ex. 62.03 Schedule of Applicants' adjusted base rate revenue requirements – Optimal Budgets
- PC Ex. 62.04 Schedule of Applicants' adjusted base rate revenue requirements – Constrained Budgets
- PC Ex. 62.05 Florida Public Service Commission, Order PSC-2024-0503-PCO-EI dated December 17, 2024 Approving Florida Power & Light Company's Interim Storm Cost Recovery Charge, in FPSC Docket No. 20240149-EI
- PC Ex. 62.06 LUMA's response to se: PC-of-LUMA-FIN-2 and related Excel file
- PC Ex. 62.07 Copies of Other Referenced ROIs

I. INTRODUCTION

A. Purpose of Report

Larkin & Associates PLLC was retained by the Puerto Rico Energy Bureau (“Energy Bureau” or “PREB”) to provide advice on matters related to utility regulation. The purpose of our report is to address various issues presented in the rate case filing by LUMA Energy, LLC and LUMA Energy ServCo, LLC (collectively “LUMA”), Genera PR, LLC (“Genera”), Puerto Rico Electric Power Authority (“PREPA”) (collectively “Applicants”). Our report, in particular, focuses on the revenue requirement being requested by Applicants. We also present background material, and discussions on assigned issues. While we discuss the requirements of the uniform accounting system that applies to electric utilities such as PREPA, the focus of the current rate case is primarily on the Applicants’ budgeted information for FY 2026 and the forecast information for FY 2027 and FY 2028 that was filed by and obtained from the Applicants.

Our report is sponsored by Ralph C. Smith and Mark S. Dady.

Mr. Smith and Mr. Dady have previously provided an expert report and testified in PREPA’s original rate case, Case No. CEPR-AP-2015-0001.

B. Background and Qualifications of Ralph Smith, CPA

Ralph C. Smith is a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant in the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination on my first sitting in 1979, received my C.P.A. license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license and my CFP certification. I am a licensed Certified Public Accountant and attorney in the State of Michigan. Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

After graduating from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 44 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where

appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada, as well as the Federal Energy Regulatory Commission and various state and federal courts.

Appended to our expert report is PC Ex. 62.01, which is a summary of my regulatory experience and qualifications.

C. Background and Qualifications of Mark Dady, CPA

Mark S. Dady is a Certified Public Accountant licensed in the State of Michigan and a regulatory consultant in the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

I received a Bachelor of Business Administration degree in Accounting with high honors from Davenport University in Dearborn, Michigan in 2001. In addition, I received a Master of Science degree in Accounting from Walsh College in Troy, Michigan in 2006. I received my C.P.A. license in 2007 and I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I have also been a member of the Michigan Association of Certified Public Accountants since 2007.

Prior to my employment with Larkin & Associates PLLC, I worked for an apparel retailer where my duties included shipping and receiving, inventory management, accounts receivable and accounts payable. I have been employed by Larkin & Associates PLLC since November 2001. As a certified public accountant and regulatory consultant with Larkin & Associates, PLLC, I have assisted with the review and analysis of regulatory filings, prepared computer spreadsheets and models, prepared discovery requests, performed accounting and regulatory research, drafted and edited testimony and written reports, and verified data. I have submitted testimony and/or expert reports on utility ratemaking matters in the following jurisdictions: California, Connecticut, Delaware, Mississippi, Ohio and Puerto Rico. I have also performed analytical work on revenue requirement issues in the jurisdictions identified above as well as in Alaska, Arizona, Hawaii, New Jersey, Pennsylvania, Virginia, and West Virginia.

Appended to our expert report is PC Ex. 62.02, which is a summary of my regulatory experience and qualifications.

D. Larkin Firm Background

Larkin & Associates, PLLC, (“Larkin”) is a Certified Public Accounting and Regulatory Consulting Firm. In April 1970, the certified public accounting firm of Larkin, Chapski & Co., was formed by former employees of Peat, Marwick, Mitchell & Co., then a “big eight”

accounting and auditing concern. In addition to the auditing, accounting and tax work typical of CPA firms, Larkin, Chapski & Co, specialized in the area of utility regulation. In September 1982, the firm was reorganized into Larkin & Associates, a certified public accounting and utility regulatory consulting firm with Hugh Larkin, Jr., as senior partner. As such, Mr. Larkin has ultimate responsibility for all regulatory consulting work performed by the firm. Larkin performs a variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. The firm has performed regulatory consulting services for numerous clients, including the PREB and its predecessor, the Puerto Rico Energy Commission.

The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates, PLLC has extensive experience in the utility regulatory field, providing expert witness testimony in over 800 regulatory proceedings, including numerous electric, gas, water, wastewater, and telephone utility cases.

E. Information Reviewed

In evaluating the Applicants' revenue requirement we reviewed LUMA, Genera and PREPA's filed testimony and exhibits, other background information, Applicants' responses to information requests, as well as the testimony and comments filed by Intervenors.

F. Other Commission Advisors

Several other Commission Advisors are addressing other parts of the Applicants' proposed revenue requirement and the Applicants' proposed rate design. As a result of the focused responsibility for analyzing various issues affecting the revenue requirement, we are not recommending a specific base rate revenue requirement for PREPA at this time, but will remain available to assist the PREB in evaluating issues and determining a final permanent base rate revenue requirement at a later stage of this PREPA base rate case.

II. BASIS OF REGULATORY ACCOUNTING - THE UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED BY THE FEDERAL ENERGY REGULATORY COMMISSION

PREPA, and LUMA as PREPA's agent, are supposed to be using the regulatory accounting system consisting of the Uniform System of Accounts ("USOA") prescribed by the Federal Energy Regulatory Commission ("FERC"), as the basis for their regulatory accounting. Although PREPA is not subject to all Federal Energy Regulatory Commission (FERC) regulations, PREPA has adopted the USOA prescribed by FERC. Moreover, using the FERC USOA for Electric Utilities is required by and is consistent with the Energy Bureau's Rate Case Filing Requirements and Definitions, which define "Accounting System as follows:

"Accounting System" means accrual accounting that conforms to U.S. generally accepted principles and is consistent to the extent feasible with the Uniform

System of Accounts for Electric Utilities as established by the Federal Energy Regulatory Commission.”¹

The Uniform System of Accounts for Electric Utilities, as prescribed by the FERC can be found in the Code of Federal Regulations at Title 18, Chapter I, Subchapter C, Part 101.²

The FERC Uniform System of Accounts provides for a standardized accounting for electric utilities using a consistent account numbering system. The account numbering plan used the FERC System consists of a system of three-digit whole numbers as follows:

100-199 Assets and other debits.

200-299 Liabilities and other credits.

300-399 Plant accounts.

400-432, 434-435 Income accounts.

433, 436-439 Retained earnings accounts.

440-459 Revenue accounts.

500-599 Production, transmission and distribution expenses.

900-949 Customer accounts, customer service and informational, sales, and administrative and general expenses.

The Uniform System of Accounts provides the following general guidance for maintaining the utility’s accounting records:

A. Each utility shall keep its books of account, and all other books, records, and memoranda which support the entries in such books of account so as to be able to furnish readily full information as to any item included in any account. Each entry shall be supported by such detailed information as will permit ready identification, analysis, and verification of all facts relevant thereto.

B. The books and records referred to herein include not only accounting records in a limited technical sense, but all other records, such as minute books, stock books, reports, correspondence, memoranda, etc., which may be useful in developing the history of or facts regarding any transaction.

C. No utility shall destroy any such books or records unless the destruction thereof is permitted by rules and regulations of the Commission.

¹ See, e.g., the PREB’s Resolution and Order dated February 12, 2025, page 21 of 34, *Rate Case Filing Requirements, Schedules B through H, Definitions*.

² See, e.g., <http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18>.

D. In addition to prescribed accounts, clearing accounts, temporary or experimental accounts, and subdivisions of any accounts, may be kept, provided the integrity of the prescribed accounts is not impaired.

E. All amounts included in the accounts prescribed herein for electric plant and operating expenses shall be just and reasonable and any payments or accruals by the utility in excess of just and reasonable charges shall be included in account 426.5, Other Deductions.

Note that paragraph E, quoted above, provides that only “just and reasonable” expenses shall be recorded for electric plant and operating expenses; any payments or accruals by the utility in excess of just and reasonable charges are to be included in a separate account, 426.5, Other Deductions.³ Strict adherence to the Uniform System of Accounts combined with regulatory and financial audits designed to examine the utility’s accounting are thus a primary way that regulators have of assuring that the utility’s recorded plant and operating expense balances are just and reasonable.

Keeping the accounting records in a manner that is consistent with the guidance on the USOA for Electric Utilities is important for a number of reasons.

First, having accurate USOA based accounting information provides a source for determining amounts that are used in the ratemaking process. While Applicants’ proposed revenue requirement is largely being driven by their proposed optimal and constrained budgets, having accurate accounting information could be used for ratemaking purposes, such as determining an uncollectibles rate. Under the USOA, Uncollectible Accounts expense is recorded in Account 904. Using recorded information, if accurately maintained, could be used for determining an uncollectibles rate by dividing the expense recorded in Account 904 by revenues for electric utility service. Information from the accounting records for a recent year, or, if available, reliable USOA-based accounting information for a number of years, could be analyzed in this manner to determine a normal and representative rate for uncollectibles that has a basis in experience and which relies upon recorded accounting information. Also, see section V of our report for a discussion of Applicants’ proposed uncollectibles expense and related concerns.

Second, having accurate information on utility plant in service and how that has been funded, can also be important for regulatory purposes. The USOA provides detailed guidance concerning accounting for utility plant. New investments in utility plant should be accurately accounted for and the accounting records being maintained by Applicants for the electric utility should also appropriately record applicable funding sources, i.e., should identify how the utility plant has been financed. Federal government infusions of funds into PREPA for hurricane and earthquake related damage restoration and for system maintenance costs have been an important source of cash flowing into the system since 2017 and continuing through the present. Appropriate accounting records on how the electric utility plant has been financed (e.g., with investor funds, with federal and Puerto Rico cash infusions, or with electric system revenues

³ Account 426 is generally considered to be one of the “below-the-line” accounts, in that costs recorded in that account are generally not allowed for purposes of determining the electric utility’s revenue requirement, although exceptions can sometimes occur.

billed to ratepayers in the current fiscal year) is important to avoid having Puerto Rico ratepayers paying twice for utility plant that they have already paid for. Because PREPA has not had access to new external financing sources for several years, and particularly during the period following the 2017 hurricanes, utility plant additions that were not financed from federal government sources have essentially been funded from ratepayer-provided revenue, i.e., from charges for utility service on a dollar-for-dollar basis in the current accounting period.

Third, and important in the current rate case, accurate accounting records are going to be needed to facilitate the reconciliation of provisional rate revenues with the permanent rate revenue requirement. Identifying amounts of differences attributable to various factors can be aided by having accurate and reliable accounting information. See section X of our report for a discussion on factors that will contribute to differences between the provisional and permanent rates revenue requirements and recommendations for the reconciliations.

LUMA witness Andrew Smith explains in his direct testimony summary at page ii, that:

... due to the state of PREPA's historical financial records and lack of a reconciled and current balance sheet, LUMA is not able to present its revenue information using the Federal Energy Regulatory Commission's Uniform System of Accounts and has limited ability to confirm the accuracy of the balance sheet and plant-in service and accumulated depreciation values.

LUMA witness Andrew Smith testifies further that LUMA's inability to fully follow the Uniform System of Accounts is **not** negatively affecting the current rate case because a cash financing methodology is being used to establish the system's revenue requirement. Specifically, he states that

... such challenges do not negatively impact this rate case and the setting of new Base Rates because the current regime is a cash financing model that does not depend on that information.

We agree with LUMA witness Andrew Smith's observation that the revenue requirement for PREPA in the current rate case is based primarily on budgeted information for FY 2026 and forecasts for FY 2027 and FY 2028, and not on historical accounting information. The revenue requirement in this case will be set based on the Energy Bureau's evaluation of the Applicants' optimal and constrained budgeted information. However, reconciliations will be needed between provisional rates and permanent rates, and having accurate accounting information for provisional rate revenues billed to customers, and for LUMA, Genera's and PREPA's spending on the budgeted items approved by the Energy Bureau for inclusion in provisional rates will be needed to facilitate reconciliations between provisional rates and the permanent rates revenue requirement.

Not having accurate and reliable accounting information available for historical periods for use in the current rate case is making what should be relatively simple and straight-forward analysis difficult. As one illustrative example, analyzing a utility's uncollectibles expense by reviewing the amounts recorded in Account 904 of the USOA, and comparing those recorded uncollectible amounts to billed revenue for electric utility service, is one way of determining an uncollectibles rate to use in the ratemaking process. That analysis can be coupled with a review of accounting information on the utility's Accounts Receivable and doubtful accounts, which should also be maintained per guidance of the USOA. Not having reliable accounting information for these items is making it difficult to perform an accounting records-based analysis of recorded uncollectibles expense, or an analysis of collections of Accounts Receivable, and has thus hampered efforts and to determine an uncollectibles rate for use in establishing the permanent rates revenue requirement. Without having USOA quality accounting information being available to aid such analysis, this also presents difficulties for the PREB to do its job to set just and reasonable rates.

While we realize that LUMA has other priorities, such as improving the reliability of the electric system, and those may have taken precedence over maintaining accurate accounting information consistent with the guidance in the USOA, we are somewhat skeptical about LUMA's claims that LUMA cannot produce accounting records in conformance with the USOA until 2028. As one step in moving toward USOA compliance, we recommend that the Energy Bureau require LUMA to complete an analysis of the June 30, 2025 recorded amounts of Accounts Receivable for collectability, and to report on and document collections and amounts determined to not be collectible and to have that completed by June 30, 2026, the end of the current fiscal year.

We also recommend that the Energy Bureau require LUMA and PREPA to work together to produce a reconciled balance sheet that conforms with USOA guidance by June 30, 2026. If LUMA and PREPA claim that is somehow not possible, we recommend that the Energy Bureau require them to present the steps that each entity is taking to produce the accounting records that will result in having a reconciled balance sheet that conforms with USOA guidance no later than by June 30, 2027, i.e., by the next of the next fiscal year. If LUMA and PREPA believe that additional resources beyond what have previously been included in their optimal and constrained budgets are needed to produce accurate accounting records that conform with USOA guidance, they should identify and explain those needs.

III. REVENUE REQUIREMENT METHODOLOGIES FOR UTILITY BASE RATES

A. Introduction

This section of our report describes methodologies that can be used to determine a utility's base rate revenue requirement. As described herein, some of these methodologies are not practical for determining the revenue requirement for PREPA in the current rate case, but could become usable at some point in the future.

Because of various factors affecting the system, we recommend using a cash-flow based methodology. We note that the revenue requirement filed by Applicants in this case uses

budgeted information for FY 2026 and forecasts for FY 2027 and FY 2028, and applies a cash-flow based methodology.

There are different types of revenue requirement models that are in use to determine utility revenue requirements. Because of PREPA's situation and its dependence upon cash flow from operations and from federal funding, a cash-flow based revenue requirement methodology, which examines in detail LUMA's, Genera's and PREPA's proposed optimal and constrained budgets for fiscal year 2026 has been presented by Applicants, and is also recommended by us as a viable method for determining the base rates revenue requirement in this proceeding and for establishing new permanent rates for PREPA in this case.

The discussion in this chapter of our report therefore focuses on briefly explaining the ratemaking methods that are available to the Energy Bureau and the one we recommend be applied to determine PREPA's revenue requirement, and why some of the commonly used methods are not applicable to PREPA's current situation.

B. Rate Base/Rate of Return

The rate base/rate of return ratemaking model is one that is widely used in the U.S. to set rates for investor-owned utilities. The revenue requirement under this method is determined using the following formulation:

$$\text{Revenues} = \text{Expenses} + \text{Depreciation} + (\text{Rate Base} \times \text{Rate of Return}).(1)$$

The "expenses" in this ratemaking formula include all of the utility's prudently-incurred operating expenses (e.g., fuel, purchased power, operations, and maintenance expense, CILT, labor, pension funding costs). Depreciation is a non-cash expense that represents the reduction in the value of the utility plant assets with the passage of time. Revenue provided in utility rates to recover depreciation expense represents a cash flow to the utility that recoups over time the investment in utility plant assets and provides a source of funding for new capital investments. The "rate base" is the book value of the used and useful portion of the utility plant (generation, transmission, distribution, and other tangible assets) that has not yet been depreciated. It is the asset base to which the "return" is applied. That "return" is the annual percentage return that must be paid to the investors that provide the capital used to finance the building of the utility's rate base assets—it is equal to the cost to the utility of that capital. For the type of utilities to which this model applies, the capital is provided by equity investors (through the sale of stock and via retained earnings) and debt investors (through the sale of bonds), and the return used to determine rates will be a weighted-average return for both the equity and debt capital.

This methodology has worked well for many years for investor-owned utilities. However, it is not well-suited for public power utilities, although there are some that use it. The equity return portion of the rate base/rate of return model is the most problematic aspect when applied to public power utilities. Publicly-owned utilities do not sell ownership interests in their enterprises. They are "owned" by the municipalities, states, or political jurisdictions in which they operate. The "equity" that appears on the books of account for public power utilities

represents earned surplus (also known as “retained earnings”), which is earnings from operations retained by the utility. It is not capital provided by issuing stock to investors. In Case No. CEPR-AP-2015-0001, the Energy Commission noted that PREPA’s “Net Position” (the approximated equivalent of owners’ “equity”) as of June 30, 2016 showed a deficit of almost \$2 billion. We expect that PREPA continues to have a deficit “Net Position” although the exact amount is not known by us with specificity. Any equity return that were to be included in developing PREPA’s rates under the rate base/rate of return methodology would need to be based upon a hypothetical equity balance.

For public power utilities like PREPA that have negative earned surplus (the expenses have been greater than income for some period of time) and have negative equity balances,⁴ a “return” on a negative capital balance has little practical meaning. In order to determine rates using this methodology for an electric utility like PREPA, one would have to assume a hypothetical capital structure. While an assumed capitalization can be a useful ratemaking tool in certain circumstances, in this instance it is not. The financial condition of PREPA should be assessed as directly as possible in this proceeding. Attempting to fit PREPA into a ratemaking methodology utilized by a different type of utility would fail to accomplish that goal. Too many assumptions would have to be included by the Applicants and the Energy Bureau in a rate base/rate of return ratemaking model in this proceeding, and we therefore do not consider it to be a viable alternative.

Recommendation: we recommend that the rate base/rate of return ratemaking model not be used for PREPA in this proceeding for the reasons described above.

C. Debt Service Coverage Ratio

The debt service coverage ratio (DSCR) methodology for ratemaking is commonly used for rate setting in the public power industry, as well as for public utilities that are organized as member cooperatives. In this method, the revenue requirement is composed of all the utility’s operating expenses, plus the expected debt service costs multiplied by the DSCR. Or, written as a formula:

$$\text{Revenues} = \text{Operating Expenses} + (\text{Debt Service} \times \text{DSCR}) \quad (2)$$

This approach does not require having accurate historical accounting information on utility plant balances or making assumptions about what investment returns might or might not be appropriate or what the mix of capital ought to be. It simply adds up all of the utility’s costs that are budgeted for the rate year and approved by the Energy Bureau. The operating expenses

⁴ As noted above, at June 30, 2016, PREPA has a “Net Position” deficit of approximately \$2 billion. The Net Position of a government owned utility is similar to owner’s equity and retained earnings of an investor owned utility. Since PREPA has a large deficit balance, that would be similar to negative owners’ equity. Thus there is no actual positive balance representing the equity investment in the utility to which a return on equity authorized by the regulatory commission could be applied.

are the same as those noted for the rate base/rate of return model, except for depreciation expense, which is a non-cash accrual.

Under this methodology, there is a need to include in rates an ability for the utility to collect more than the minimum required amount in order to support financial stability. This can be accomplished by including amounts for debt service payments, consisting of principal and interest payment requirements, plus an element of “coverage” wherein the debt service requirements are multiplied by the DSCR. Where this method is used, information concerning minimum DSCR from the utility’s bond indentures and additional information based on market conditions and DSCRs applicable to comparable utilities is used by the regulator to determine an appropriate DSCR for use in calculating the utility’s revenue requirement. The DSCR provides for some degree of financial stability and the ability to withstand fluctuations of revenue and expenses between rate cases, without creating a cash flow emergency and a need for an emergency rate increase.

There is one aspect of PREPA’s financial condition that this Debt-Service Coverage based revenue requirement model is unable to address completely: capital expenditures. The Puerto Rico electric utility has capital expenditure requirements that must be made in order to maintain and improve the utility plant. After Hurricanes Irma and Maria in 2017, a key source of funding for capital expenditures has been governmental funds. Key components of Applicants’ proposed revenue requirements, which are being addressed by other PREB consultants, are based on assumptions and projections of federal government funding of capital expenditures and maintenance for fiscal year 2026. For several years, electric system capital spending has been limited by available funding sources, to levels approaching or even falling below basic maintenance.⁵ Therefore, much needs to be done to shore up operational reliability.

The DSCR revenue requirement model can meet some of those capital expenditure needs through the additional cash flow beyond amounts needed to pay debt service, i.e., beyond amounts needed to cover principal and interest payments on the debt. The “coverage” component of the allowed DSCR can enable the utility to manage fluctuations in revenues and expenses and cash needs between rate resetting. The DSCR methodology is appropriate in a situation in which debt service payments are being made and where access by the utility to new debt for funding capital expenditure needs is available. Currently, PREPA is not paying principal or interest on debt because of the stay that is in place in the Title III proceeding. Since the 2017 hurricanes, our understanding is that PREPA has not been able to fund electric system capital expenditures from sources other than cash from revenues and government funding. Because of its financial situation, including the Title III bankruptcy, PREPA has not been making principal and interest payments on Legacy Debt and has been unable to raise new capital from the financial markets. This is not expected by us to continue be the case for PREPA until the Title III process has been completed.

Under normal circumstances, an electric utility could utilize the capital markets by issuing debt sufficient for the additional monies needed to meet the capital expenditure requirements; however, that option is not currently available to PREPA. That process of financing capital expenditures with investor-supplied debt spreads the cost of financing utility

⁵ See, e.g., the Expert Report of Dr. Horowitz and Dr. Fisher of Synapse, which addresses from an operational perspective PREPA’s capital expenditures, maintenance, and electric system reliability.

assets over the life of the asset (or life of the bond issuance), thereby lowering the annual revenue requirement impact to ratepayers of utility capital projects. Moreover, that is the condition to which PREPA should eventually be returned; i.e., when PREPA's internal cash flow in a year is insufficient to fund necessary capital projects, the utility can obtain the necessary incremental funding from the capital markets at reasonable cost. That is not currently the case. Therefore, this DSCR revenue requirement model is, at this time, unable to support PREPA's return to a more normal state of reliable operations and should therefore not be used. After the Title III process is completed and PREPA's access to new external debt funding is resumed, applying the DSCR revenue requirement model to determine system revenue requirements should be revisited.

D. The “Modified Cash Basis Approach”

A “modified cash basis approach” to determining the system's revenue requirement focuses on covering all of the system's cash requirements—operating expenses (plus subsidies such as CILT) by comparing those requirements with sources of incoming cash. Sources of income cash for the system currently include revenues billed for electric service and government funding. Under this approach, capital expenditures that are not reimbursed from federal funding sources are recovered from ratepayers annually on a dollar-for-dollar basis. The revenue requirement equation for this method is as shown below:

$$\text{Revenues} = \text{Expenses} + \text{Debt Service} + \text{Capital Expenditures} \quad (3)$$

$$\text{Revenues} = \text{Expenses} + \text{Capital Expenditures} \quad (3a)$$

As noted above, while the Title III process continues, Debt Service payments are currently zero. No payments of principal or interest on PREPA's legacy debt have been or are currently being made because of a stay that has been in effect during the Title III bankruptcy proceeding.. Consequently, until the Title III process is completed and/or until PREPA obtains access to additional debt financing, there is no debt service to include in the revenue requirement.

This revenue requirement method is different from the DSCR method in that it directly includes the full amount of capital expenditures that the utility expects to make, that are not associated with federal funding sources, in the rate year. That is, for every dollar of expected capital expenditures that are not federally funded, the revenue requirement would be increased by that same dollar, resulting in a dollar-for-dollar annual recovery of expected capital spending

on new and replacement plant.⁶ This “Modified Cash Basis” approach is an unusual ratemaking model that is applicable when the utility is not able to fund capital expenditures by accessing debt funding, such as by issuing bonds or bank note financing. It is unusual to require ratepayers to pay directly on a dollar-for-dollar basis in the current period for the utility’s non-federally funded capital expenditures; however, this is the situation that currently faces the system and is expected by us to continue until the Title III process resolves the PREPA legacy debt issues and until PREPA’s access to new investor-supplied debt financing is restored.

This sort of ratemaking methodology—having ratepayers fund all of the utility’s capital expenditures, that are not subject to federal funding, in the year incurred—would not normally be employed by a regulatory authority because it does not match the period benefitted by the useful life of the new utility plant investment. It creates a mismatch between (a) the time when ratepayers would pay for the plant and infrastructure (in the year in which the expenditures occurred) and (b) the time during which that utility plant and infrastructure would be providing service (over the asset’s useful life; or, if financed with bonds, over the period in which the bond financing would be outstanding.) Instead of financing utility plant over a long-term period, using annual ratepayer revenue to fund capital expenditures front-loads the burden onto Puerto Rico electric system ratepayers and effectively has such ratepayers finance the new utility plant investment by paying PREPA on a dollar-for-dollar basis in the current year for all of PREPA’s capital spending in that year that is not subject to federal funding reimbursements.⁷

This form of revenue requirement methodology can be appropriate in limited unusual circumstances, such as where the utility has experienced severe financial distress and has no access to capital other than from its customers, which is the situation that is continuing so far in FY 2026 for the Puerto Rico electric system.

Such a “modified cash basis” approach therefore should not be considered as a permanent model for ratemaking for PREPA. Rather, it should be viewed as a temporary means of deriving the revenue requirement for PREPA as part of the overall process of restoring PREPA’s financial health. It is being employed in the current case in order to address PREPA’s continuing financial situation. It should be employed only during periods when PREPA does not have access to new bond market financing at reasonable costs.

⁶ According to the updated proposed revenue requirements that LUMA provided in Attachment 1 to the response to PC-of-LUMA-FIN-2, the Applicants have proposed \$904.0 million of estimated non-federally funded capital expenditures for FY2026 be included in the revenue requirement under the proposed optimal budget and \$618.2 million under the constrained budget. The Applicants have also projected \$1.795 billion of federally funded capital expenditures for FY 2026 under the optimal budget and \$1.534 billion under the constrained budget. Other PREB consultants are addressing those proposals by the Applicants.

⁷ Other PREB consultants are addressing the specifics of the federal funded and non-federal funded capital expenditures that are included in the Applicants’ proposed revenue requirement. Our report discusses related ratemaking considerations in the context of the model and ratemaking methodology that is being used by the Applicants and the Energy Bureau’s consultants to determine permanent rates in the current rate case.

E. DSCR with CapEx, the “Modified DSCR”

A ratemaking formula based on a DSCR methodology that also accounts for PREPA’s continuing but hopefully temporary inability to access the capital markets is shown as Equation (4), below.

$$\text{Revenues} = \text{Expenses} + \text{Legacy Debt Obligation} + (\text{Debt Service} \times \text{DSCR}) + \text{Additional CapEx} \quad (4)$$

In this revenue requirement model, as in the DSCR model shown in Equation (2), revenues are to be equal to all operating expenses and debt service costs adjusted to account for debt service coverage. The cash flows available to the utility from issuing new debt and from the revenues obtained related to the debt service coverage component of the revenue requirement would be available to fund expected capital expenditures.⁸ If the Company’s capital expenditure needs exceed the cash flows available from debt service coverage, then an additional increment (termed “Additional CapEx” in Equation (4)) is added to the revenue requirement to provide for the additional monies necessary to meet the utility’s prudent and reasonable construction needs. This modified version of a revenue requirement method does not appear to be suited to PREPA for fiscal year 2026, since the Title III process is continuing and PREPA has not been paying principal or interest payments on legacy debt and has not obtained access to new debt financing. However, this may be appropriate for consideration for use in determining PREPA’s revenue requirements in FY 2027 and/or in FY 2028, once the Title III process has been completed and a Legacy Debt Obligation is known and if access to outside debt financing has been restored to PREPA in those years. We note that the current rate case is considering a period of three years, FY 2026, FY 2027 and FY 2028. So, while not applicable to PREPA’s current situation in FY 2026 to date, this modified revenue requirement model could become applicable and worthy of consideration to subsequent periods if circumstances are different.

As an illustrative hypothetical example of how this modified method could work, if a hypothetical public power utility had expected rate year expenses of \$800, and debt service of \$200 with a DSCR of 1.5, rates would be designed to collect \$1,100 in revenues for the rate year. [Revenues = \$800 (expenses) + \$200 (debt service) + \$100 (DSCR margin)⁹]. As a result of that ratemaking process, the utility would have \$100 cash available for funding capital expenditures. That cash flow would come from the coverage allowed above the actual debt service costs. Once the Title III process has been completed, an amount for a Legacy Debt Obligation would need to be considered and would be an addition to the \$1,100 in this hypothetical illustration.

In this hypothetical illustration, if the utility’s capital needs are \$100 or less, the “Additional CapEx” term in Equation (4) is zero; the capital expenditure needs are met by the traditional DSCR model. In that case, no further adjustment to the standard DSCR ratemaking

⁸ The cash flows available from debt service coverage are generated by the “coverage” (the total amount of the debt service times the DSCR) being greater than the debt service. The difference will be cash available to the Company to fund capital expenditures.

⁹ \$200 (debt service) x 1.5 = \$300 (total debt service and margin); \$300 (total debt service and margin - \$200 (debt service) = \$100 (DSCR margin).

formula is necessary, other than to provide for the Legacy Debt Obligation once the Title III process has been completed. If, however, the utility's capital expenditure needs are \$125 (and only \$100 is available from the standard DSCR model), then an increment of \$25 [\$125 capital expenditure needs less \$100 available cash flow from the DSCR margin] would be added to rates in this "Modified DSCR" ratemaking model as ratepayer funding of utility capital expenditures, i.e., as "Additional CapEx."

Based on the facts presented in the current PREPA rate case, for FY2026, the system's non-federally funded capital expenditures that are approved by the PREB would essentially be funded in FY 2026, i.e., in the current fiscal year, entirely by ratepayers. Such funding of current year CapEx by PREPA's ratepayers is necessary because, as explained herein, PREPA does not have access to external finance markets and cannot issue new bonds finance its capital expenditures.

As discussed in this Report, because the additional capital expenditures allowed in this model are not investor-supplied funds but are, instead, ratepayer-supplied funds, they should be treated as such and not considered to be revenues, as would be the case if the capital expenditures had been funded by investors. The ratepayer-provided funding of current year, i.e., FY 2026, capital expenditures should be accounted for by LUMA as PREPA's agent, as contributions in aid of construction. On PREPA's balance sheet, the customer-contributed funding of capital expenditures would be an offset to PREPA's investment in utility plant in service. As a result, PREPA would subsequently record less net depreciation and amortization prospectively than if the customer-funding of PREPA's CapEx were accounted for as revenue, rather than as customer-provided funding of construction projects.

As noted above, the DSCR model shown in Equation 2 is widely-used for rate-setting by public power utilities and electric cooperatives. Once PREPA re-establishes access to external debt financing, which has not happened to date in FY 2026, but which may happen in future years once the Title III process has been completed, such a method could provide a reasonable basis for the ratemaking methodology for PREPA over the long-term. It should therefore be the method of choice after PREPA is returned to financial health. However, due to PREPA's current financial situation, and its inability to access the capital markets, that model is not currently sufficient to meet the needs to begin PREPA's return to a sound financial condition *and* to fund and operate a well-maintained electric grid.

Therefore, as long as PREPA continues to be blocked from accessing the capital markets, that standard DSCR ratemaking model should be augmented to account for necessary rate year capital expenditures that PREPA is not able to fund through other available cash flows.

Recommendations: While PREPA is in a state of not being able to access new external financing on reasonable terms, ratepayers become the only available source for financing PREPA's needed capital expenditures (i.e., the capital expenditures that are not subject to federal financing). Reasonable and necessary capital expenditures must continue to be made to enable the electric system to be restored to a level where reliable electric service can be provided. Currently, for non-federally funded CapEx and system operating costs, the Puerto Rico electric system has no reliable options for obtaining those monies other than from its ratepayers. Therefore, it is reasonable in this unusual circumstance to modify the standard DSCR ratemaking

model to account for ratepayer funding of PREPA's necessary capital expenditures during a period, such as FY 2026, when PREPA thus far has no other sources of financing.

The ratemaking model set out in Equation (4), above, must be viewed, therefore, as a temporary solution to the unique financial problems currently faced by PREPA and its customers here in Puerto Rico.

We recommend that the Modified DSCR be used in the current rate case due to the prevailing circumstances but that it not be viewed by the Energy Bureau as a permanent ratemaking technique. Once PREPA is able to issue additional long-term debt, the Modified DSCR should no longer be employed by the Energy Bureau for ratemaking purposes. At that time in an appropriate rate review proceeding before the Commission, ratepayers should be prospectively relieved of the aspect of providing annual dollar-for-dollar financing of PREPA's capital expenditures. At that point, PREPA would be financing its capital needs beyond its internally generated cash flow through the issuance of long-term debt and from the margin provided by the DSCR, as is normally done by public power electric utilities.

We recommend that the Commission utilize the Modified DSCR ratemaking model for purposes of determining PREPA's base rate revenue requirement in the current rate case, noting that the debt service portion may have to be temporarily set at zero, in recognition that no principal or interest payments are being made on PREPA's legacy debt. Once the Title III Court resolves the issues of responsibility for PREPA's legacy debt and if PREPA is able to access new debt financing to finance CapEx or other system needs, inclusion of a debt service component and appropriate coverage ratio in the revenue requirement formula would be necessary and appropriate.

Once PREPA is able to issue additional long-term debt at reasonable costs, the Modified DSCR should no longer be employed for ratemaking purposes, ratepayers should be relieved of the aspect of providing annual dollar-for-dollar financing of PREPA's capital expenditures that are beyond the amount of the DSCR margin. Once access to financial markets is restored and PREPA can issue debt at reasonable costs to finance capital expenditures, the Company should finance its capital needs beyond its internally generated cash flow through the issuance of long-term debt and from the margin provided by the DSCR, as is normally done by public power electric utilities.

IV. APPLICANTS' REVENUE REQUIREMENT

A. Introduction

A utility's system annual revenue requirement is the total dollars necessary each year to cover its reasonable costs.

For Puerto Rico's electric system, the total revenue requirement is a combination of the individual revenue requirements of PREPA, LUMA, and Genera.

To determine base rates (i.e., the rates whose basis is the annual revenue requirement), regulators allocate responsibility for the total revenue requirement among defined customer groups; then create rates that, when paid by all the members of those groups, produce the necessary revenues. For a discussion of how regulators translate an annual revenue requirement into rates, see the expert report of Zachary Ming.

A proposed revenue requirement is always based on a “rate year”—a defined period of time during which the utility system will incur the costs that the annual revenue requirement must reflect. In this proceeding, the rate year is Fiscal Year 2006—July 1, 2025, through June 30, 2026.

Depending on the particular revenue requirement methodology being used, those costs can include operating and maintenance expenses, fuel, taxes, depreciation, capital expenditures, the principal and interest associated with its debt financing a “coverage” or “margin” amount above debt service payments; and, for for-profit utilities, a reasonable return (profit) on investment.

A revenue requirement under some methodologies is based on cash needs. It must produce rates that in turn produce from customers the current funds needed to plan and run the system. A regulator bases the revenue requirements on detailed budget information. In this proceeding, the budgets containing this information are the Optimal Budgets and Constrained Budgets proposed by PREPA, LUMA, and Genera.

One of the elements is a “Margin,” defined by the Energy Bureau’s filing requirements¹⁰ as:

a calculated amount, above the sum of LUMA’s, PREPA’s, and Genera’s FY2026 budgeted operating expenses and non-reimbursable capital expenditures, that is typical of the coverage that lenders require of nonprofit borrowers with investment-grade-rated long-term debt. Examples of margins are: (a) X.XX times interest charges (i.e., as a Times Interest Expense Ratio (TIER)), (b) Y.YY times annual principal and interest charges (i.e., as a debt service coverage ratio (DSCR)), (c) FY2026 budgeted operating expenses and non-reimbursable capital expenditures projected to require cash payments divided by 0.ZZ (i.e., as an Operating Ratio), or (d) W.WW times the FY2026 Optimal Budget amount of base rate revenues (calculated without the margin). A detailed explanation and supporting calculations shall accompany the proposed Margin.

Additional discussion concerning “Margin” is presented in section VI of our report.

While most of the Puerto Rico electric system’s revenue requirement has features in common with all utilities, two elements add complexity. The first is debt. Because of PREPA’s bankruptcy (handled under Title III of the federal PROMESA statute), PREPA is currently making no payments to its bondholders—because the Title III proceeding temporarily relieved PREPA of any obligation to make those payments. As well, PREPA has not had, for several years, any access to investor-supplied financing. (It is common for utilities to borrow money, mostly to make capital expenditures for physical plant. Because that physical plant will last many years, long-term financing allows the utility receive the money upfront, but then pay it back, with interest, over the lifetime of the asset or the duration of the utility bonds. In that way, the funds to pay bondholders back will come from all customers who benefit from the asset over its lifetime.) In this proceeding, the Energy Bureau will need to consider how much, if any, to

¹⁰ See Resolution and Order dated February 12, 2025 in NEPR-AP-2022-0003, page 25 or 34, Rate Case Filing Requirements, Definitions.

include in the revenue requirement to reflect the annual payments that PREPA must make on its legacy debt, an amount which likely will not be known with certainty until the Title III process is completed. If the Title III process concludes and makes clear the level of those annual payments, the revenue requirement should include an amount for the Legacy Debt Obligation: however, that amount is not currently known.

The second unusual feature concerns PREPA's obligation to its retirees for pensions and post-retirement health care. To the extent that PREPA has been funding this obligation, PREPA has done so on a pay-as-you-go (also known as cash payment) basis, rather than from a trust that PREPA has built up over time by charging its customers for the pension costs that were being incurred during working lives of the PREPA retirees. The latter approach is sometime referred to as an accrual accounting approach, because it assigns the retiree costs to the customers during the working lives of the employees who will become retirees, on the grounds that those customers are the beneficiaries of the utility service provided by those employees during those periods. Unless a non-ratepayer funding source becomes available,¹¹ the revenue requirement for the electric system needs to reflect a reasonable estimate of the costs to comply with PREPA's obligations to its retirees.

The cost of running Puerto Rico's electric system also includes fuel and purchased power, various subsidies required by statute, and the cost to provide electricity to municipalities in lieu of PREPA's paying property taxes. Customers pay for these costs through special clauses (sometimes called riders, adjustors or true-up mechanisms) outside of base rates. The Energy Bureau periodically adjusts the inputs to these clauses to reflect changes in actual costs. For more detail on these, see sections VIII and VII of our report.

Once a regulator determines the necessary revenue requirement, it compares that requirement to the revenue produced by current rates to determine whether the electric system has a revenue deficiency, and the amount. That deficiency determines the amount of rate increase necessary to produce revenues that match the revenue requirement.

B. The Updated Base Rate Revenue Requirement Claimed by Applicants

Applicants originally filed their proposed revenue increase requests on July 3, 2025 and have since updated their request. As required by the Energy Bureau's filing requirements, Applicants present two versions of their proposed FY 2026 budgets, which form the basis of their requested revenue requirement: (1) optimal and (2) constrained. Applicants updated their requested revenue requirement on August 29, 2025 in response to ROI PC-of-LUMA-FIN-2.¹² For purposes of our report, we focus on Applicants' updated revenue requirement. Schedules showing Applicants' proposed revenue requirements under optimal and constrained budgets are presented with our report in PC Ex. 62.03 and PC Ex. 62.04. For additional details reconciling Applicants' original July 3, 2025 filing amounts with Applicants' updated revenue requirement

¹¹ The Puerto Rico government has provided for some funding for the PREPA retiree pensions; however, that funding may not be continuing. The Energy Bureau included an amount for PREPA retiree pensions in the revenue requirement used to determine the current provisional rates. See Resolution and Order of July 31, 2025, at p 37

¹² Copies of ROIs referenced in our report are attached in PC Ex. 62.06 and PC Ex. 62.07.

request, including tables showing the reconciling components, please see Appendix I to our report.

V. BAD DEBT (AKA UNCOLLECTIBLES) EXPENSE

A. Introduction

Some customers pay their bills late. Other customers do not pay, or pay only part. These failures, if not addressed, leave a utility with insufficient cash to operate. One solution is to raise the rates for the customers who pay, by including in the revenue requirement an amount for uncollectibles. The other solution is to ensure that the utility has an effective collection process. The Energy Bureau must consider both approaches.

To explain the situation technically: When a utility sends bills to customers, the amounts stated in the bills become the utility's Accounts Receivable. When customers pay, the utility the Revenue account and debits the Accounts Receivable account. Large Accounts Receivable balances, and particularly balances that are aging (meaning bills unpaid for a long time), indicate a possible problem with the utility management's procedures for collections.

Accounts Receivable is an account shown on the asset side of a company's balance sheet. Calculating and recording a reserve for uncollectibles is also common. The reserve for uncollectibles is a contra account on the company's balance sheet; it reduces the Accounts Receivable balance to reflect billed amounts for electric service that management views as uncollectible. Management typically makes an allowance for bad debts, also known as a reserve for uncollectibles, based on historical experience.

Accounts Receivable aging is an analysis of the amount of time that billed amounts are being carried by a company, prior to either being collected or being written-off as uncollectibles. Large amounts of Accounts Receivable, especially if amounts have aged more than, say, 60 days, raise concerns not only about both collection diligence but also about whether management is overly optimistic about collectability. Bills unpaid for more than, say, 120 days or for over a year, strongly suggests uncollectibility.

B. Position of the Applicant

LUMA is assuming 2.97% for bad debt expense, which the Energy Bureau's predecessor approved in PREPA's 2017 Rate Order.¹³

Using that percentage, in its optimal revenue requirement LUMA included bad debt expense of \$158,980,998 in RY2026, \$166,713,168 in RY2027, and \$167,782,434 in RY2028.¹⁴

¹³ Exhibit 1.0, Direct Testimony of Alejandro Figueroa, page 42, lines 788-789 from LUMA's rate case filing

¹⁴ Schedule B-1 Optimal from LUMA's rate case filing

In its constrained revenue requirement, again using the 2.97% from the 2017 Rate Order, LUMA included bad debt expense of \$129,957,435 in RY2026, \$129,532,871 in RY2027, and \$125,148,056 in RY2028.¹⁵

LUMA provided an aging report for its accounts receivable balance at the beginning of the rate year. It shows the aging amounts for all PREPA government customers and separates customers to which CILT applies from customers to which CILT does not apply.¹⁶ An analysis of the accounts receivable aging report shows a total accounts receivable balance of \$846,118,602. Of that balance, LUMA shows \$168,957,686 at least 120 days overdue, and \$584,499,965 at least 365 days overdue. These two figures total to approximately 89% of LUMA's accounts receivables balance at least 120 days overdue.¹⁷

C. Position of Intervenor OIPC on Uncollectibles

OIPC witness Sanabria addresses LUMA's efforts to collect accounts receivable and uncollectibles. Uncollectibles expense is a cost that is included in the utility's revenue requirement. Uncollectibles are ultimately collected from customers who pay their bills for electric service.

OIPC witness Sanabria's testimony on uncollectibles at page 13 notes:

LUMA has admitted that there are no benchmarking studies or useful industry comparisons to support [the 2.97% uncollectibles rate]. LUMA further stated that it will only be able to produce a credible, accurate factor at some point in the future.¹⁸

On page 14, Mr. Sanabria states:

This approach is inconsistent with recent regulatory practice. In previous years, specifically in the FY2024 and FY2025 budgets, the Energy Bureau approved bad debt expenses based on a 1.5% factor, which LUMA itself applied in its filings.¹⁹ The sudden proposal to nearly double that factor, without providing updated, data-driven justification, raises serious concerns about its appropriateness and fairness to consumers.

At pages 14-15, he includes a discussion of the data that has been submitted by LUMA:

The data submitted by LUMA in response to ROI-OIPC-of-LUMA-NONPHYS OPS-56 shows uncollectible amounts of \$137,288 for FY2024 and \$398,979 for FY2025, which correspond to bad debt percentages of 3% and 9%, respectively.

¹⁵ Schedule B-1 Constrained from LUMA's rate case filing

¹⁶ Exhibit 2.0, Direct Testimony of Andrew Smith, page 51, lines 1026-1029 from LUMA's rate case filing

¹⁷ Schedule C-11 from LUMA's rate case filing

¹⁸ See, LUMA's Response to ROI# OIPC-of-LUMA-NONPHYS OPS-57.

¹⁹ See, Case NEPR-MI-2021-0004/*Review of LUMA's Initial Budget, LUMA's Request for Approval of T&D Budgets and Submissions of GenCo Budgets for FY2025 and Budget Allocations for the Electric Power System*, dated May 25, 2024, Exhibit 1, at page 28, footnote #5.

In addition, LUMA's own accounting records show that it recorded extraordinary write-offs of approximately \$77 million in FY2024 and \$339 million in FY2025 as part of a "cleanup" of historical receivables. These extraordinary write-offs are substantially higher than the amounts approved by the Bureau as "bad debt" and further highlight the inconsistencies in LUMA's reporting. This discrepancy raises a fundamental concern. Bad debt should only reflect actual uncollectible sales. It should not be inflated by old unpurged receivables, poor customer data, or accounts that could still be collected with proper effort. By including legacy write-offs as uncollectible debt, LUMA artificially increased the bad debt factor to 9%, unfairly inflating the revenue requirement and shifting costs onto customers.

On page 15 Mr. Sanabria presents his recommendation for uncollectibles, as follows:

The higher the percentage authorized by the regulator as "bad debt," the less incentive the utility will have to be efficient in its collection practices. For this reason, the Energy Bureau should either cap the bad debt factor at a reasonable level, such as the 1.5% historically applied, or disallow recovery of any inflated amounts tied to legacy write-offs and inefficiencies. This approach ensures that customers are not forced to subsidize poor collections' performance and that the utility remains under pressure to improve its revenue protection practices.

D. Evaluation of LUMA and OIPC Positions on Uncollectibles

OIPC witness Sanabria's testimony makes some valid points about uncollectibles. We agree with his conclusion that LUMA has inadequately supported its proposed uncollectible rate of 2.97%.

We also agree with Mr. Sanabria's recommendation that, based on the available evidence, a reasonable rate would be the 1.5% that has been approved by the Energy Bureau for computing the uncollectibles component of the revenue requirement, as well as for purposes of computing provisional rates.

In previous years, specifically in the FY2024 and FY2025 budgets, the Energy Bureau approved bad debt expenses based on a 1.5% factor, which LUMA itself applied in its filings.

The Energy Bureau's July 31, 2025 Resolution and Order on Provisional Rates at page 30 states as follows concerning the Bad Debt Factor:

LUMA proposes a 2.97% bad-debt factor, citing that factor's appearance in PREPA's 2017 Rate Order. LUMA offers no aging analysis, receivables study, or other empirical evidence to support the continued validity of that-figure. The Independent Consumer Protection Office ("OIPC") recommends a 1.5 percent factor, consistent with the allowances approved by the Energy Bureau in the FY 2024 and FY 2025 budgets. OIPC emphasizes that LUMA's proposed factor nearly doubles the cost to customers "without any updated, data-driven justification," and notes that no record evidence supports the higher percentage.

A bad-debt allowance is appropriate, to ensure that the funding level approved by this Resolution and Order is actually collected. But LUMA has not justified the 2.97 percent

factor with current data or analysis. Accordingly, the Energy Bureau GRANTS LUMA's request to include a bad-debt provision but sets the factor, for provisional rate purposes, at 1.5 percent of projected billed revenues. LUMA shall revise Schedule C-2 and its associated provisional rate design to reflect this adjustment. In the permanent-rate phase we will determine the appropriate number. For that purpose, LUMA shall promptly supply information, via witness attestation, witnesses, that gives credible support to some number. ICPO can of course make a discovery request for current information on collectability, then present that information when ICPO submits intervenor testimony.

In PC-of-LUMA-PROV-39(g), Accounts Receivable aging information was sought. LUMA's response stated that:

Please refer to PC-of-LUMA-PROV-39_Attachment 1 for an aging of Accounts Receivable by customer class in total and outstanding for (a) 0-30 days, (b) 30-60 days, (c) 60-90 days, and beyond (d) 90-120 days, (e) 120 days to 365 days and (f) beyond 365 as at May 31, 2025 and June 30, 2025. The data provided in ROI-LUMA-AP-2023-0003-20250324-PREB 072_Attachment 1 that was submitted as part of the July 3rd filing contained an error. Please refer to PC-of-LUMA-PROV-39_Attachment 1 for the correct information.

In PC-of-LUMA-PROV-39(h), the following was asked of LUMA:

Was an analysis of the aged accounts receivable balances as of 6/30/2025, or as of any other date, used by LUMA to develop the projected FY 2026 amount for Bad Debt? If not, explain fully why not. If so, please identify and provide the analysis conducted by LUMA of aged accounts receivable and explain how that resulted in LUMA's proposed FY 2026 amount for Bad Debt in LUMA's proposed Provisional Rates Revenue Requirement.

LUMA's response to PC-of-LUMA-PROV-39(h) stated that no analysis was conducted, and did not provide any analysis.

LUMA's attempt to nearly double the 1.5% Bad Debt Factor used in recent years to 2.97% with the only justification being that 2.97% was used several years ago in the previous rate case, CEPR-AP-2015-0001, without providing updated, data-driven justification is not acceptable.

Besides not having adequate support for continuing to use an outdated bad debt factors of 2.97% from the previous rate case, CEPR-AP-2015-0001, in the current case to set permanent rates, we also note that LUMA has claimed that it is improving the collection process and has formed a "Revenue Protection" team.

LUMA has stated in response to PC-of-LUMA-PROV-38, (b) and (c) that it is improving its efforts at collections and has formed a specialized Revenue Protection team:

To effectively manage Accounts Receivable, LUMA has formed a specialized "Revenue Protection" team dedicated to collecting overdue debts and ensuring a focused effort,

from the outset, to mitigate the accumulation of past-due accounts. LUMA's Revenue Protection team plays a crucial role in overseeing collections, identifying delinquent accounts, enforcing credit policies, and managing bankruptcy cases. The team is committed to ensuring fair treatment for customers experiencing financial difficulties while safeguarding LUMA's financial health, which is essential for LUMA to be able to safely and provide reliable service. LUMA has implemented a standardized 30/60/90-day collection process that involves proactive customer outreach via phone, email, and letters to facilitate payment plans for outstanding balances.

LUMA is enhancing its Customer Care and Billing System (CC&B) to automate the identification of accounts requiring collection actions during daily billing cycles, promoting consistent and efficient collection practices across various customer segments. Additionally, LUMA is nearing the completion of a Request for Proposal (RFP) to source vendor support for an initiative designed to improve digital processing capabilities, which will enhance vendor management and expand payment options for customers, thereby facilitating smoother payment transactions and improving revenue recovery. With these planned enhancements, LUMA will be able to accept payments at over 900 locations throughout the island.

This raises an expectation that collections will improve over the experience in recent years, and thus suggests that the Uncollectibles factor going-forward could be lower. However, there does not appear to be sufficient experience yet with LUMA's "Revenue Protection" team or its efforts to improve collections from which to reliably quantify an adjustment to the 1.5% Bad Debt Expense Factor that the Energy Bureau approved for the FY 2024 and FY 2025 budgets and used for the calculation of the provisional rate revenue requirement.

E. Recommendation

Based on currently available information, we recommend that the Energy Bureau use an uncollectible rate of 1.5% for calculations in the base rate revenue requirement. If better information becomes available, the uncollectibles rate to be used should incorporate consideration of such additional information.²⁰

We also recommend that, effective with quarterly factor filings that occur after the Energy Bureau's final decision on base rates in the current proceeding, that the Energy Bureau include a similar uncollectible factor in the calculation of the FCA and PPCA rates. The inclusion of a provision for uncollectibles in the FCA and PPCA rates will help address concerns over system cash flow issues related to the undercollection of FCA and PPCA revenues from customers non-payment of billed amounts for such revenues.

²⁰ Additional information on collections of billed revenue, analysis of the collectability of amounts in Accounts Receivable and uncollectibles recorded by LUMA in Account 904, Uncollectible Accounts Expense, is being sought.

VI. DEBT SERVICE AND MARGIN

A. Debt Service and Coverage for Legacy Debt

Applicants' revenue requirement makes certain assumptions about amounts for PREPA's legacy debt. For prior years and continuing to date through FY 2026, pursuant to a stay imposed by the Title III bankruptcy Court, PREPA has not been paying principal or interest on its legacy debt. Ultimately, responsibility for PREPA's legacy debt will be determined by the Title III Court, a process which is continuing and has not yet reached a final resolution.

Applicants' calculation of its revenue requirement was based on applying a debt service coverage ratio (DSCR) of 1.3 times of the principal and interest payments associated with legacy debt that was presumed to be retained at PREPA. Applicants have provided two calculations: one for a low legacy debt and one for a high legacy debt assumption, as reproduced below:

Table 1: Applicants' Proposed Debt Service and Coverage Allowance – Low Legacy Debt Service

LUMA Proposed Low Legacy Debt Service Coverage Allowance			
	FY2026	FY2027	FY2028
Component (Optimal and Constrained Budgets)	\$ Millions	\$ Millions	\$ Millions
Low PREPA Debt Service	\$ 592	\$ 582	\$ 548
Adjusted Debt Service Coverage Ratio	1.3	1.3	1.3
Debt Service Coverage Allowance (30%)	\$ 178	\$ 175	\$ 164
Debt Service with Coverage Allowance	\$ 770	\$ 756	\$ 712
Source: LUMA Schedule B-4			

As discussed on page 13 of the Resolution and Order dated July 31, 2025, LUMA witness Mr. Andrew Smith explained in his testimony that the \$178 million of Net Operating Income for FY 2026 represents the surplus revenue that is above PREPA's annual expenditures, which PREPA must demonstrate to convince future creditors of its positive cash flow capability upon exiting bankruptcy proceedings.

Table 2: Applicants’ Proposed Debt Service and Coverage Allowance – High Legacy Debt Service

LUMA Proposed High Legacy Debt Service Coverage Allowance			
	FY2026	FY2027	FY2028
Component (Optimal and Constrained Budgets)	\$ Millions	\$ Millions	\$ Millions
High PREPA Legacy Debt Service	\$ 1,090	\$ 1,082	\$ 1,052
Adjusted Debt Service Coverage Ratio	1.3	1.3	1.3
Debt Service Coverage Allowance (30%)	\$ 327	\$ 325	\$ 316
Debt Service with Coverage Allowance	\$ 1,417	\$ 1,407	\$ 1,367
Source: LUMA Schedule B-4			

Currently there is no debt service being paid by PREPA on its legacy debt. Consequently, the debt service and coverage would represent additional base rate revenue requirement increases beyond what PREPA’s ratepayers are currently paying.

These amounts are uncertain, and will likely be different once PREPA’s financial restructuring is completed pursuant to the Title III process. The amounts and specific components of the legacy debt that would be retained at PREPA are not known with certainty.

B. Position of Intervenor Bondholders

Bondholders’ witness Susan Tierney, Ph.D., is a Senior Advisor at Analysis Group, Inc. (“Analysis Group”). Dr. Tierney’s direct testimony address the ratemaking treatment of debt as well as affordability considerations in the rate case. She addresses whether and how PREPA’s outstanding debt should be reflected in PREPA’s revenue requirement; the inclusion of a “proposed margin” based on a debt service coverage ratio (“DSCR”); and the manner in and extent to which issues of affordability should factor into the permanent rate for PREPA.

At pages 5-6, Dr Tierney states that:

... electric utility rates should include the costs to finance reasonable and prudent investments and business operations, including the cost of servicing existing debt. Accounting for the cost of debt in a utility’s revenue requirement is critical because the electric industry involves investment in capital-intensive assets with long useful lives. It therefore is inconsistent with ratemaking principles of efficiency, intergenerational equity, and the provision of adequate service at just and reasonable rates to routinely use cash from operations (as opposed to financings through capital markets) as the source of funds to invest in such long-lived, capital-intensive assets. Under cost-of-service ratemaking, therefore, a utility’s revenue requirement should include the cost of capital including debt service. When regulators set revenue requirements that properly account for debt costs, customers benefit because the utility can maintain financial stability, attract capital on reasonable terms and avoid imposing on the current customer base the

large upfront costs associated with cash-funded capital investments in assets with long useful lives. Failure to properly account for debt costs jeopardizes these important goals.

At page 6, Dr. Tierney recommends using a placeholder for the Legacy Debt Obligation amount and a Rider to recovery those amounts:

... electric utility rates should include the costs to finance reasonable and prudent investments and business operations, including the cost of servicing existing debt. Accounting for the cost of debt in a utility's revenue requirement is critical because the electric industry involves investment in capital-intensive assets with long useful lives. It therefore is inconsistent with ratemaking principles of efficiency, intergenerational equity, and the provision of adequate service at just and reasonable rates to routinely use cash from operations (as opposed to financings through capital markets) as the source of funds to invest in such long-lived, capital-intensive assets. Under cost-of-service ratemaking, therefore, a utility's revenue requirement should include the cost of capital including debt service. When regulators set revenue requirements that properly account for debt costs, customers benefit because the utility can maintain financial stability, attract capital on reasonable terms and avoid imposing on the current customer base the large upfront costs associated with cash-funded capital investments in assets with long useful lives. Failure to properly account for debt costs jeopardizes these important goals.

Dr. Tierney references the proposal by Applicants' witness Sam Shannon, in his July 3, 2025 testimony (hereafter "Shannon Testimony"), at p. 38, concerning the development of a Legacy Debt Rider:

("[H]aving the policy discussions in this contested proceeding will allow parties to provide input on these riders in advance of their effective dates. And finally, once the Energy Bureau makes an informed decision on the mechanics of each rider, the initial start of the LDR [Legacy Debt Rider] can be a simple compliance filing with the CILT [Contributions in Lieu of Taxes – Municipalities] and SUBA [Help to Humans Subsidy] riders").

C. Evaluation of Bondholders' Witness Recommendations

Virtually all of the issues raised in Mr. Hurley's and Mr. Hogan's testimony are the subject of review by other PREB consultants; namely Eng. Justo González and Mr. Guímel Cortés. We mention the concerns of those Bondholders' witnesses in our report because their resolution by the Energy Bureau will affect the total amount of the Applicants' base rate revenue requirements. Please see the reports of other PREB consultants that address capital spending and maintenance project prioritization, issues involving access to federal funding, and other potential non-ratepayer sources for Puerto Rico electric system funding.

Concerning Bondholders' witness Tierney's recommendations, we agree that it is generally preferable to have long-lived utility plant investments being funded by ratepayers over longer periods, such as periods represented by the duration of long-term debt, such as bonds, or over the estimated depreciable lives of the utility plant. However, that has not been available to PREPA. Capital expenditures for the electric system that have not been funded by or reimbursable from federal funds have largely been funded by ratepayers on a dollar-for-dollar

basis in each year. Or, if federal funding and ratepayer funding was insufficiently available to fund all needed infrastructure projects, the results have been that projects were delayed or not done. Thus, the long-term objective should be to restore PREPA's financial health and to enable needed investments in electric utility plant to be recognized in PREPA's revenue requirement over longer periods which better approximate the use of such assets. For FY 2026, however, the primary sources of funding for capital projects continue to be federal money and ratepayer money.

Concerning, Dr. Tierney's criticisms of the Applicants' calculations of Debt Service and Margins, we agree that Debt Service Coverage would be applicable to new bond financing or other forms of long-term debt financing, rather than to a currently unknown amount of Legacy Debt Obligation. We believe that the Applicants were trying to comply with the Rate Case filing instructions and that resulted in the Applicants including estimated amounts for Debt Service and for Margins in their proposed revenue requirement.

Concerning Bondholders' witness Tierney's recommendation that a Legacy Debt Rider surcharge be developed, this could be done as part of the rate design in the current rate case; however, developing a Legacy Debt Rider surcharge, we believe, would be more appropriately done after the Title III Court has determined what PREPA's Legacy Debt Obligation is.

D. PREPA's September 26, 2025 Motion Concerning Legacy Debt

On September 26, 2025 the PREPA filed a Motion among other things, objecting to the consideration of repayment of any Legacy PREPA Obligations and to the "Legacy Debt Rider" that was proposed by Applicants. On page 4 of that Motion, PREPA asserted that:

The Energy Bureau lacks the statutory authority to address any issues related to the Legacy Obligations at this time, because doing so would violate PROMESA, be inconsistent with the February 2025 Fiscal Plan for the Puerto Rico Electric Power Authority ("PREPA Fiscal Plan"), and be highly speculative considering the current state of PREPA's Title III debt restructuring process.

On September 29, 2025, the Hearing Examiner²¹ clarified that the Energy Bureau has already stated, via the filing requirements, that it will consider whether to include in the revenue requirement an estimated proxy for legacy debt. See also the Provisional-Rate Order (July 31, 2025) at 31-32. The Hearing Examiner asserted that in his opinion PREPA's arguments were incorrect but ultimately stated that:

PREPA can use its post-hearing brief to argue against including a legacy debt estimate in rates. But I am not removing the question from this case. What I ask from the witnesses are (a) useful thoughts about credible numbers to use, and (b) methods for reconciling estimated debt amounts with later-determined actual debt amounts.

E. Recommendation on Debt Service

²¹ Hearing Examiner's Order Establishing (a) Agenda for the September 29 Conference, and (b) Certain Procedures for the Evidentiary Hearing

Concerning the Applicants' proposed inclusion of Debt Service in the base rate revenue requirement for FY 2026, we recommend that those amounts be excluded until there is a resolution of PREPA's Legacy Debt Obligation by the Title III Court. This recommendation includes a timing element – waiting for the Title III process to be completed – and a judgment element – determining an amount to be reflected in the revenue requirement. Currently, due to the Title III bankruptcy Court stay, no payments of principal or interest on the legacy debt are being made. We therefore recommend against using a “guesstimate” of an amount for the Legacy Debt Obligation. We recommend waiting for a final decision from the Title III Court before any amounts for a Legacy Debt Obligation are included in the revenue requirement.

The Applicants' presentation, as noted above in our report, has included amounts for the Energy Bureau's consideration, which are available if the Energy Bureau wishes to use a non-zero amount. Again, we urge heightened caution by the Energy Bureau in addressing amounts for a Legacy Debt Obligation, and advise and recommend that the Energy Bureau not “front run” the Title III Court in identifying a non-zero amount for inclusion in the revenue requirement. In our professional judgment, the most prudent course of action for the Energy Bureau would be to simply await the determination of the Title III Court on what the Legacy Debt Obligation is, and once that is known, to then proceed with designing a revenue requirement and related rate design to address the collection of that amount from ratepayers. In summary, we recommend that the Energy Bureau await the outcome of the Title III bankruptcy process prior to including an amount for PREPA legacy debt or related debt service coverage in base rates.

Concerning new sources of investor-provided financing, if PREPA is able to access new debt financing at reasonable terms during the fiscal years 2026 through 2028 rate case cycle, we recommend that the Energy Bureau provide for the inclusion of debt service and debt service coverage for that new debt in base rates after the facts are known with specificity about such new debt issuances.

Concerning the development of a Legacy Debt Rider surcharge, we recommend that be deferred until there is a resolution of PREPA's Legacy Debt Obligation by the Title III Court. After such a final determination has been obtained, the development of an appropriate method of charging such amounts to ratepayers, such as in a Rider, can be determined as an element of rate design.

Concerning ideas on how an amount for a Legacy Debt Obligation could be reconciled: If the collection of such an amount from ratepayers is exclusively prospective and the collection can be accomplished in a separate Rider, keeping the revenue requirement associated with this separate from the other components of the FY 2026 budgets that are being reviewed and analyzed by the Energy Bureau could avoid having to make a potentially complicated reconciliation for the impact of a Legacy Debt Obligation on fiscal year 2026 results. In summary, a combination of the following components of ratemaking treatment to provide rate recovery could help avoid complications associated with a reconciliation that might be present if an alternative ratemaking treatment were to be used: (1) treating the Legacy Debt Obligation as a separate component of the revenue requirement once it is known from a Title III Court decision, (2) placing recovery of that into a Legacy Debt Rider, and (3) treating it as an item for prospective revenue requirement collection only (i.e., not attempting to reconcile any related amounts back to July 1, 2025 or to fiscal year 2026 results).

F. “Margin” Calculations and Inclusion in the Revenue Requirement

There are various way in which a “Margin” component of a utility’s revenue requirement can be calculated. While Applicants have presented one calculation, using legacy debt service amounts, there are alternatives for calculating “Margin” that are identified in the definition and which can be considered by the Energy Commission. Recall that the definition of “Margin,” in the Energy Bureau’s filing requirements²² is:

a calculated amount, above the sum of LUMA’s, PREPA’s, and Genera’s FY2026 budgeted operating expenses and non-reimbursable capital expenditures, that is typical of the coverage that lenders require of nonprofit borrowers with investment-grade-rated long-term debt. Examples of margins are: (a) X.XX times interest charges (i.e., as a Times Interest Expense Ratio (TIER)), (b) Y.YY times annual principal and interest charges (i.e., as a debt service coverage ratio (DSCR)), (c) FY2026 budgeted operating expenses and non-reimbursable capital expenditures projected to require cash payments divided by 0.ZZ (i.e., as an Operating Ratio), or (d) W.WW times the FY2026 Optimal Budget amount of base rate revenues (calculated without the margin). A detailed explanation and supporting calculations shall accompany the proposed Margin.

Applicants propose an amount of Margin that is based on applying a DSCR of 1.3, alternatively to two estimates of PREPA’s Legacy Debt Obligation.

G. Bondholders’ Witness Tierney’s Testimony on “Margin”

At pages 6-7, of her direct testimony, Bondholders’ witness Dr Tierney criticizes Applicants’ calculation of “Margin” which she claims should not be applied to Legacy Debt:

... LUMA’s inclusion of a proposed amount of funds to support a debt service coverage ratio (“DSCR”) as part of rates is inappropriate if, as appears to be the case, LUMA’s proposed margin is designed to cover a DSCR for repayment of future, as-yet-unissued debt, and yet the proposed margin is calculated based on an assumed level of legacy debt. The inclusion of that specific DSCR amount is unexplained and inconsistent with the proposed cost-of-service, which does not include future, unscheduled debt obligations (and assumes cash-based funding of utility investments). Customers should not be made to bear additional costs tied to uncertain or speculative future financing needs. When the amount needed for repayment of legacy debt is known, as well as the amount of any possible issuance of future debt, such costs should then be included in rates.

H. Recommendation on “Margin”

Inclusion of “Margin” in a utility’s revenue requirement can be appropriate in many circumstances. Margin essentially provides a “cushion” to the utility by providing additional revenues that are beyond the specifically approved operating expenses and ratepayer-funded capital expenditure amounts. The extra amount represented by the Margin helps the utility address and manage unanticipated fluctuations in revenue or costs that can occur.

²² See Resolution and Order dated February 12, 2025 in NEPR-AP-2022-0003, page 25 or 34, Rate Case Filing Requirements, Definitions.

One of the alternative ways of addressing “Margin”, as noted in the definition, is as an Operating Reserve. That alternative uses the sum of the utility’s base rate revenue requirement (calculated without the reserve). The revenue requirement will include Energy Bureau approved operating expenses and capital expenditures to be funded by ratepayers (i.e., not covered by federal reimbursements). The calculation divides that revenue requirement amount by an Operating Reserve factor to derive the amount of “Margin.” An illustrative example of this method would be as follows: If a utility had \$1,000 of operating expenses and capital expenditures for its approved revenue requirement and an Operating Reserve of 4% (or its inverse, 96%), the \$1,000 divided by 0.96 would produce a result of \$1,042, or a “Margin” amount of \$42. The “Margin” based on the Operating Reserve method would then be added to the base rate revenue requirement.

Because of the way the revenue requirements are being developed in the current rate case by the detailed review of the Applicants’ optimal and constrained budgets, a separate Margin amount is not needed. Nor is there currently a sufficiently clear basis for calculating one using an Operating Reserve method.

The collections of the related revenue for Margin by the utility as part of its overall base rate revenue collection could be used to accumulate an equity balance (or to reduce a deficit that had been accumulated from prior years). Additional funding beyond amounts approved for specifically budgeted operating expenses or for specifically budgeted capital expenditures to be funded by ratepayers during the current year could also be used to pay for capital expenditures that are not being funded by other sources. In the current rate case, the Applicants’ proposed operating costs and capital expenditures are being reviewed in detail. Moreover, approved budgets for capital expenditures beyond those that are expected to be covered by federal funding, under the ratemaking methodology being used in this rate case will be borne by ratepayers on a dollar-for-dollar basis for the FY 2026 revenue requirement as will Energy Bureau approved amounts for operations, maintenance and other expenses. Given those circumstances, we recommend against charging ratepayers for an additional amount of “Margin” for the FY 2026 revenue requirement. Accordingly, we are not recommending that an amount for “Margin” be included in the FY 2026 revenue requirement.

Concerning the amount of “Margin” to be included in the revenue requirement, we recommend that such amount not be based on estimates of PREPA’s Legacy Debt Obligation as Applicants have proposed. In this respect, we agree with Bondholders witness Tierney that the Margin amount should not be based on PREPA’s Legacy Debt Obligation or tied to uncertain or speculative future financing needs.

If new sources of financing become available for access by PREPA during the remainder of FY 2026, or during FY 2027 or FY 2028, the terms of that financing, once they are known, can be used at that time to prospectively determine a Debt Service Coverage-based Margin amount. However, no information on new financing was included by Applicants, and such information is not known. As noted above, Applicants’ proposed Margin amounts were based exclusively on Legacy Debt, not on any of the other alternative calculations.

In the future, as the Puerto Rico electric system moves away from dollar-for-dollar funding by ratepayers of capital projects in the year in which such expenditures are made, the

calculation of a Margin amount to include in future revenue requirements deserves reconsideration.

VII. SUBSIDIES AND CILT

Subsidies and CILT are the subject of surcharges that the Energy Bureau sets annually, typically effective with new rates on July 1, of each fiscal year, and which are evaluated and set separately by the Energy Bureau outside of PREPA base rate cases. Customers' bills collect these amounts through "reconciliation clauses."

A. Introduction

In addition to the clauses for fuel and for purchased power, a customer's bill includes three other clauses: the Help to Humans clause, the Help to Non Humans clause, and the Contributions in Lieu of Taxes clause. Each of these clauses recovers from customers the costs associated with subsidies that support programs important to Puerto Rico's people and its economy. Most of the items addressed by these three clauses recover from all customers the cost of subsidies—statutory price breaks—enjoyed by other customers.

The *Help to Humans (SUBA-HH)* clause recovers the costs associated with these items:²³

- Credit for Consumption of Electrical Equipment Necessary to Preserve Life
- Residential Service for Public Housing Projects Rate - RH3
- Lifeline Residential Service Rate - LRS (Nutritional Assistance Program)
- Residential Fixed Rate for Public Housing under Ownership of the Public
- Housing Administration (RFR)
- Residential Fuel Oil Subsidy
- Public Lighting (Municipal)
- Puerto Rico Energy Bureau Assessment

This clause currently applies all customer kWh usage, except for the base usage contained in the Residential Fixed Rate. By generating their own energy and customers with self-generation have avoided the kWh-based charges by which these subsidies have been recovered from ratepayers,

The residential fuel oil subsidy, which is recovered through the Help to Human clause, warrants special mention. It appears as a discount on the monthly electricity bills paid by residential customers in these categories: handicapped, elderly, or college students; and customers taking service under either the Lifeline Residential Service (LRS) Rate or the Residential Service for Public Housing (RH3) Rate. It applies to customers in those categories "with monthly consumption of up to 500 kWh."²⁴ PREPA adjusts the Residential Fuel Oil

²³See PREPA's Tariff Book at Original Sheet No. 56.

²⁴*Id.* According to PREPA's tariff book, the fuel oil subsidy is available as follows:²⁴

For the first \$30 per barrel of fuel oil, excluding natural gas, customers under this subsidy will receive a credit equivalent to the Fuel Oil Subsidy

Subsidy (FOS) quarterly. The cost of this subsidy is recovered from all customers through the Help to Humans clause, which itself is updated annually.

The *Help to Non-Humans (SUBA-NHH)* clause covers the cost of providing discounted electricity rates to certain institutions rather than to individual residential customers. These subsidies benefit entities such as churches, social welfare organizations, PREPA-operated irrigation systems, and select tourism facilities. Specifically, this clause recovers the costs associated with these items:²⁵

- Analog Rate to the Residential to Churches and Social Welfare Organizations
- General Agricultural Service - GAS
- Credit for Incentives to the Tourism Sector (Hotel Discount)
- Residential Rate for Communal or Rural Aqueducts
- Credit to Small Merchants in Urban Centers (Downtown 10% Subsidy)
- Residential Rate to Common Areas of Residential Condominiums
- Act 73-2008 Industrial Tax Credit
- Irrigation District

Like the Help to Humans clause, this clause applies to all customer usage, except the base usage contained in the Residential Fixed Rate.

The “*Contribution in Lieu of Taxes*” (*CILT*) clause covers the cost of a program by which PREPA, instead of paying property taxes, supplies a portion of the electricity consumed by municipalities at no charge.²⁶ The statute establishing the CILT benefit directs PREPA to calculate a cap on each municipality’s subsidy, requires municipalities to reduce their consumption by stated percentages, and varies each municipality’s CILT benefit depending on the amount of reduction.²⁷

For each of these three clauses, the cost is recovered through a charge, sometimes called a “factor.” In this context, a factor is a cents/kWh amount, such as 1.0847 cents/kWh, which was

Factor multiplied by the customer’s monthly consumption in kWh, up to a consumption of 400 kWh.

For customers with consumption between 401 and 425 kWh, the customer will receive a credit equivalent to the amount received with a consumption of 400 kWh.

For customers with a consumption of between 426 kWh to 500 kWh, the credit will be phased out from the credit received at 425 kWh to reach 0 at 500 kWh.

²⁵See PREPA’s Tariff Book at p. 58.

²⁶Public-lighting consumption is excluded from the CILT cap and recovered through the separate ‘Public Lighting (Municipal)’ cost line in SUBA-HH. See PREPA’s Tariff Book at p. 54.

²⁷See Act 83-1941, section 22(b).

the factor for Help to Humans package of subsidies during part of Fiscal Year 2025.²⁸ The Energy Bureau computes the factor by dividing the total dollars to be recovered from all customers for the particular clause by the total projected annual sales to all customers (minus sales to customers in the excluded categories). The resulting figure, the factor, is a \$/kWh decimal, such as, again, the 1.0847 cents/kWh for the Help to Humans package of subsidies. On a customer's monthly bill, LUMA multiplies that cents/kWh factor by the customer's consumption for that month, producing a dollar amount that appears as the charge for that package of subsidies.

The Energy Bureau's predecessor set the annual factors for the SUBA-HH, SUBA-NHH, and CILT in PREPA's 2017 rate case. The Energy Bureau has updated these factors annually outside of the base rate process, for implementation on July 1 of each year.

The three clauses are reconciliation clauses. Their annual factors recover the total dollars resulting from adding together (a) projections of cost for the upcoming fiscal year and (b) a reconciliation component for a prior 12-month period. For the new SUBA-HH, SUBA-NHH and CILT, annual factors proposed by LUMA for implementation on July 1, 2025, the reconciliation period is the 12 month period May 2024 through April 2025.

To restate: The Energy Board calculates each clause's factor through a three-step annual process. First, the utility forecasts the total cost of providing subsidized electricity to all eligible NHH customers for the coming year—in other words, the cost-based revenues that PREPA forgoes because of the subsidy. Second, the utility reconciles any difference between the prior year's collected amount and actual subsidy costs for that prior year, refunding ratepayers if too much was collected or charging them more if collections fell short. Third, the utility divides this combined amount (i.e., the prospective amount plus the reconciliation amount) by projected retail kWh sales for the next period (not counting the baseline consumption block under residential Tariff RFR). This calculation produces a per-kilowatt-hour charge that spreads NHH subsidy costs across all customers (except excluded customers).

Because these clauses recover costs from customers based on their kWh usage, customers who reduce their usage, such as by installing rooftop solar under the net-metering program, reduce their support for these subsidy programs. Net-metering customers do have these factors applied to their net inflow (i.e., inflow minus outflow). But if their self-supply covers all of their consumption, they have no net kWh consumption, so they make no contribution to these subsidies.

In this rate case, the Energy Bureau must evaluate these subsidies to consider removal of any items not statutorily authorized or which are otherwise determined to be inappropriate or no longer needed, and to verify the accuracy of the values that go into the calculations. The Energy Bureau will also review the effects on the factors of customers' late payments and non-payments, and other measures to better match cost incurrence with the collection of the revenue associated with that cost. Finally, the Energy Bureau will evaluate proposals to change the rate design for the subsidies, including whether the charges should continue to be on a per-kWh basis, or fixed monthly charges, or some combination.

²⁸*Resolution and Order*, In Re: Permanent Tariff of the Puerto Rico Electric Power Authority, Case No. NEPR-MI-2020-0001, June 30, 2024.

B. Position of the Applicant

LUMA's optimal revenue requirement includes LUMA-calculated revenue from CILT, SUBA-HH, SUBA-NHH, & EE Riders for each year FY2026, FY2027, and FY2028 of \$320,077,800 and contra-revenue of \$279,076,694 for each year.²⁹

LUMA's constrained revenue requirement includes LUMA-calculated revenue from CILT, Subsidies, & EE Riders for FY2026 of \$320,077,800, and \$279,076,964 for each year FY2027 and FY2028, and contra-revenue of \$279,076,964 for each year.³⁰

The difference between the revenue amount of \$320,077,800 and the contra-revenue amount of \$279,076,964 is the EE Rider revenue, which amounts to \$41,001,106.

LUMA calculated the \$320,077,800 annual factor revenue by multiplying an estimated number of kWh by a per kWh rate for each rider and then adding up the revenues from the four annual factor riders. For all four riders, LUMA estimated 16,022,315,765 kWh energy usage, which is the forecasted kWh sales for RY2026.

LUMA multiplied the estimated energy usage by a \$0.005841 per kWh CILTA rate to calculate revenues of \$93,586,346 from the CILTA rider.

LUMA multiplied the estimated energy usage by a \$0.010740 per kWh SUBA-HH rate to calculate revenues of \$172,079,670 from the SUBA-HH rider.

LUMA multiplied the estimated energy usage by a \$0.000837 per kWh SUBA-NHH rate to calculate revenues of \$13,410,678 from the SUBA-NHH rider.

LUMA multiplied the estimated energy usage by a \$0.002559 per kWh EE rate to calculate revenues of \$41,001,106 from the EE rider.³¹

LUMA used slightly different annual factor rates from its permanent rate calculation for the SUBA-HH rider in its provisional rate calculation. In its calculation for provisional rates, LUMA used \$0.008589 per kWh for the SUBA-HH factor.

LUMA is also proposing rate design changes for the annual factors to be effective for fiscal year 2027. Specifically, LUMA proposes to move from the current energy charge for each rider to recovery through a fixed monthly charge, which would become effective July 1, 2026, i.e., for fiscal year 2027. See, e.g., LUMA Exhibit 20.00, page 32, line 748 to line 753.

C. Evaluation of Applicant Position

The per kWh rates used by LUMA to calculate the above-described amounts of revenue are not the rates that have been approved by the PREB for implementation on July 1, 2025.

On June 30, 2025, the PREB issued a Resolution and Order approving rates for LUMA to use for the CILTA, SUBA-HH, SUBA-NHH, and EE factors. In its filing, LUMA used rates in its provisional and permanent rate calculations that differ from the corresponding annual factor

²⁹ Schedule B-1 Optimal from LUMA's rate case filing

³⁰ Schedule B-1 Constrained from LUMA's rate case filing

³¹ Schedule E-2 Riders from LUMA's rate case filing

rates that were approved by the PREB for implementation on July 1, 2025, i.e., for fiscal year 2026. The table below reflects the difference in rates:³²

Table 3: CILTA, SUBA and EE Rates Approved for Fiscal Year 2026 Compared with Factors Used by LUMA for its Permanent Rates Revenue Requirement Calculations

Factor Name	Factor Approved for July 1, 2025 Implementation (\$/kWh) (A)	Factor Used by LUMA for Provisional Rates (\$/kWh) (B)	Factor Used by LUMA for Permanent Rates (\$/kWh) (C)	Difference between Factors Approved July 1, 2025 and Factors LUMA used for Provisional Rates (D) = (A) - (B)	Difference between Factors Approved July 1, 2025 and Factors LUMA used for Permanent Rates (E) = (A) - (C)
CILTA	\$ 0.004417	\$ 0.005841	0.005841	\$ (0.001424)	\$ (0.001424)
SUBA-HH	\$ 0.012558	\$ 0.008589	0.01074	\$ 0.003969	\$ 0.001818
SUBA-NHH	\$ 0.001091	\$ 0.000837	0.000837	\$ 0.000254	\$ 0.000254
EE	\$ 0.000853	\$ 0.002559	0.002559	\$ (0.001706)	\$ (0.001706)

Notes and Source:

Col. A: PREB Resolution and Order dated June 30, 2025 in Case No. NEPR-MI-2020-0001

Col. B: LUMA Ex. 20.03 - Rate Design for Provisional Rates, Excel file "LUMA Ex. 20.03 (7.03.25) Rate Design for Provisional Rates," Tab "Rate Inputs"

Col. C: LUMA Revenue Requirement Schedules, Excel file "LUMA Revenue Requirement Schedules (7.03.25)," Tab "E-2 Riders"

Col. D: Col. A - Col. B

Col. E: Col. A - Col. C

The CILTA, SUBA-HH, SUBA-NHH and EE rates in effect as of July 1, 2025, i.e., for FY 2026, have already been set by the PREB outside of the base rate revenue requirement process in the current rate case. The PREB's rate design consultant, Zachary Ming, is addressing an issue of whether exclusively kWh-based charges continue to be how these subsidies should be recovered from ratepayers. Requiring that a portion of the revenue requirement for these subsidies be prospectively charged on some basis other than electric sales (i.e., on a per-kWh basis), such as a monthly charge that, is thus being evaluated as a rate design issue, not a revenue requirement issue.

We also recommend that the Energy Bureau seek input from its legal advisors concerning to which components, if any, the PREB can apply discretion, versus which components are statutorily mandated.

D. Position of Intervenor OIPC on the Irrigation District Subsidy

The Irrigation District Subsidy is a component of the SUBA-NHH rate. OIPC witness Sanabria addresses the Irrigation District Subsidy at pages 18-21 of his testimony.

At page 18, Mr. Sanabria acknowledges the statutory basis for the Irrigation District provision:

³² PREB Resolution and Order dated June 30, 2025 in Case No. NEPR-MI-2020-0001

“*Puerto Rico Electric Power Authority Act*”, Act No. 83 of May 12, 1941, as amended, establishes in Section 24:

“Section 24. — [Coordination and Integration of Irrigation and Hydroelectric Projects] (22 L.P.R.A. § 214)

(a)...

(b) In carrying out its duties under the next preceding subsection, the Authority shall pay directly all costs and expenses incurred by it. The Authority shall be reimbursed for all such costs and expenses, including a fair share of the Authority’s own overhead and operating expenses attributable to the Puerto Rico Irrigation Service, South Coast, as determined pursuant to subsection (a) above, from the funds available in the Commonwealth Treasury for the operation and maintenance, repair, reconstruction, construction of extensions, improvements and enlargements of the works or systems, constructed and operated and maintained pursuant to the Public Irrigation Law of 1908, approved September 18, 1908 [22 L.P.R.A. §§ 251--259] and laws amendatory thereof or supplementary thereto. There shall be advanced to the Authority, from time to time, from said Irrigation funds in the Treasury, amounts sufficient to provide a working fund adequate at all times to meet all of said costs and expenses promptly. Said funds shall be held and administered by the Authority in the same manner as its own funds but shall be used by it only for the payment of said costs and expenses

He states further that:

In Case CEPR-AP-2015-0001/ *Puerto Rico Electric Power Authority Rate Review*, the Bureau determined that “(...) non-agricultural water rates should cover their costs, unless a reduction from cost is necessary to ensure that the customer will remain “on the system” to contribute something to fixed costs—a concept we will discuss in the context of the load retention discount at Part Three-II(C)(4).”³³

At page 19, Mr. Sanabria raises a rate design issue concerning from which group of customers the related costs should be recovered:

The costs of irrigation service should be covered, in the first instance, through the tariff established for non-agricultural customers. If those costs cannot be fully recovered, they should then be reimbursed by the Central Government. Finally, if after these two sources there are still unrecovered costs, only as a last resort should they be borne by consumers through the NHH Subsidy.

He explains that OIPC opposes such costs for the following reasons:

³³ See, CEPR-AP-2015-0001/ *Puerto Rico Electric Power Authority Rate Review*, Final Resolution and Order, dated January 10, 2017, at pages 89-91.

We oppose it because PREPA have treated this subsidy as fixed, recurring, and the primary funding source. This interpretation is contrary to both statute and regulatory precedent. Consumer-funded subsidies are a last resort, not the first, and electricity customers should not be forced to shoulder this burden ahead of the parties responsible.

Moreover, he states at page 20 that PREPA has not been diligent in seeking reimbursement from the Government of Puerto Rico for such costs:

PREPA has failed for at least twenty years to collect reimbursements from the Treasury.³⁴ This long-standing inaction directly contributes to the continued reliance on consumer subsidies.

At page 21, Mr. Sanabria recommends that the PREB deny inclusion in the revenue requirement for the Irrigation District Subsidy:

The OIPC respectfully recommends that the Bureau deny LUMA's request for \$4.15 million in subsidies, as it is inconsistent with law, regulatory precedent, and sound public policy. The Bureau should reject it and require PREPA to meet their statutory obligations without imposing additional burdens on Puerto Rico's electric consumers.

E. Evaluation of OIPC's Position on the Irrigation District Subsidy

A component for the Irrigation District Subsidy has been included by LUMA in the SUBA-NHH rate that the Energy Bureau approved for implementation on July 1, 2025 in Case No. NEPR-MI -2020-0001, which occurred outside of the current base rate review process. As such, the current cost recovery of the Irrigation District Subsidy is part of the annual factor rate, specifically, the SUBA-NHH, which is charged to ratepayers on a per-kWh basis. Because the Irrigation District Subsidy has been included in the SUBA-NHH rate for fiscal year 2026, and the Applicants have reflected their estimates of SUBA-NHH revenue for 2026, costs for the Irrigation District Subsidy are technically not part of the Applicants' requested base rate revenue deficiency or base rate revenue increase in the current case. Moreover, over and under recoveries of the SUBA-NHH rate have traditionally been part of the annual resetting of those rates as part of the annual factor review and rate resetting process, which, as noted, has occurred outside of the base rate case process.

Concerning the issues raised by the OIPC regarding the Irrigation District Subsidy, because the resolution of these concerns appears to depend on legal analysis, which we are not providing, we recommend that the Energy Bureau seek and receive advice from its legal advisors.

³⁴ See, Case NEPR-MI-2021-0004/*Review of LUMA's Initial Budgets, Motion in Compliance with January 23rd, 2024, Resolution and Order* dated April 22, 2024.

VIII. FUEL AND PURCHASED POWER ADJUSTORS

Two of PREPA's largest expenses are for fuel and purchased power. PREPA recovers fuel and purchased power expense via special mechanisms that are adjusted quarterly (or more frequently if required by the PREB).

PREPA currently recovers fuel and purchased power expense in its proposed fuel and purchased power adjustment mechanisms through the FCA and PPCA rates, which are updated on a quarterly basis (or more frequently if changes are determined to be needed by the PREB).

Switching the frequency of PREPA's rate adjustments for fuel and purchased power costs onto a monthly basis, as PREPA had been doing historically prior to the 2017 rate case (rather than on a quarterly basis, which is the current FCA and PPCA filing cadence required by the PREB and followed by LUMA), is one way to help address system cash flow needs. But that would also involve more frequent filings and monthly rate instability, so we are not recommending it.

As noted in Section V above, including an uncollectibles factor is another option to address cash flow issues related to collection by PREPA of billed rates for FCA and PPCA. Currently, there is no uncollectible factor consideration in the development of the FCA and PPCA rates. To the extent that customers do not pay their bills for electric service, of which FCA and PPCA rates are significant components, the non-collection of the billed rates, i.e., uncollectibles, is one component of cash-flow problems that the system has been faced with. Including an uncollectible component in the FCA and PPCA rates is one simple way to address related cash flow concerns with non-collection of billed FCA and PPCA rates, and we recommend that the Energy Bureau implement it, effective with the first FCA and PPCA rate resetting that occurs after permanent base rates for FY 2026 become effective.

A. Fuel Cost Adjustor

In this section, we address the accounts that are included in Fuel Expense, and that are used in the Fuel Cost Adjustor.

The following costs are included in the Fuel Adjustor:

A. Purchase Fuels

- 1) Residual Number 6
- 2) Light Distillate No. 2 (Diesel)
- 3) Natural Gas
- 4) Propane
- 5) Additives

B. Cost of Fuel Transportation (40 ¢ per barrel)

C. Inspection

D. Laboratories

E. Storage

F. Handling

G. Delays

H. Taxes

1) Municipal Patent (applies to fuel No. 6 and 2)

2) Excise Tax (applies to fuel No. 2)

3) Federal Tax (applies to fuel No. 6 and 2)

I. Fuel Hedging

Such costs are generally recorded in the following accounts under the FERC Uniform System of Accounts for Electric Utilities:

All costs related to Fuel are registered in the following accounts:

- Gas Power Generation – Fuel: account 01-4008, sub-account 54700
- Steam Power Generation – Fuel: account 01-4009, sub-account 50100 ^[L]_[SEP]
- Natural Gas Power Generation – Fuel: account 01-4041, sub-account 54701 ^[L]_[SEP]

Costs registered in these accounts are used for the computation of the monthly amount to recover or reimburse to clients. ^[L]_[SEP]

All payables are registered initially on account 01-2321, sub-account 23225, with the exception of tank rental costs, fuel inspection and sampling, and the invoices from Natural Gas, which are on account 01-2321, sub-account 23215. ^[L]_[SEP]

B. Purchased Power Cost Adjustor

In this section, we address the accounts that are used to record purchase power and renewables expense for the Purchased Power Cost Adjustor:

A. Energy Purchases from cogenerators AES and EcoEléctrica

1) Payment for Energy

2) Payment for Capacity

B. Energy Purchase to Renewable Energy Projects

1) Payment for Energy

2) Costs Associated with Renewable Energy Certificates (REC's)

a) Registration in the North American Renewables Registry

Costs for purchased power from AES and EcoEléctrica have been recorded in the following accounts:

- Ecoeléctrica: account 01-4014, sub-account 55500-050-609-0000 (PUERTO RICO POWER & ELECT/Other Power Supply Expense/ Purchased power/ Compra Energía Ecoeléctrica/ Unspecified) ^[L]_[SEP]

- AES: account 01-401, sub-account 55500-050-610-0000 (PUERTO RICO POWER & ELECT/Other Power Supply Expense/Purchased power/Compra Energía AES/Unspecified) ^[L]_[SEP]

Costs registered in these accounts are used for the computation of the monthly amount to recover or reimburse to clients. ^[L]_[SEP]

All payables are registered initially on account 01-2321, sub-account 23235 (Accounts Payable/Purchased Power-Ecoelectrica, AES y Energia Renovable).

Costs for purchased power for renewables are generally recorded in subaccounts to FERC account 547.

C. Frequency of Updating the Fuel and Purchased Power Adjustors

PREPA's Fuel and Purchased Power Adjustors provide for the recovery by PREPA of total fuel and purchased power costs, which are large and which historically have been volatile.

Currently, proposed revisions to PREPA's Fuel and Purchased Power Adjustor rates are filed quarterly by LUMA, and, if warranted are adjusted by the Energy Bureau. More frequent revisions than quarterly can be made if determined to be needed by the PREB.

Prior to the 2017 rate case, PREPA's fuel and purchased power adjustor rates had been adjusted monthly. Since the 2017 rate case, the FCA and PPCA rates have been adjusted quarterly, subject to more frequent updates if determined to be appropriate by the PREB. The quarterly updating provides customers with a three-month period of rate stability. However, if fuel and purchased power costs increase during the quarter, such cost increases could require PREPA to finance the difference between Adjustor Revenue and the Fuel and Purchase Power costs that have been incurred by PREPA.

As noted earlier in our Report, PREPA continues to have cash flow problems and does not have access to capital markets to fund CapEx or working capital requirements. As such, PREPA's ability to finance fuel and purchased power cost fluctuations, particularly increases, between FCA and PPCA rate resetting, can contribute to cash flow problems involving diversion of funds from other purposes.

Currently, all of PREPA's fuel and purchased power costs are recovered in the quarterly adjustments to the FCA and PPCA rates. There are no fuel and purchased power costs recovered in PREPA's base rates.

D. Inclusion of Uncollectible Factor in Developing Fuel and Purchased Power Rates

PREPA's FCA and PPCA rates do not include any consideration of uncollectibles. Not being able to fully collect amounts billed for FCA and PPCA rates, particularly in periods in which costs have been increasing, has contributed to system cash flow concerns. The temporary under-collection and less than full collection of such costs due to customers paying late or not paying at all has contributed to situations where inadequate cash flow was provided on a timely basis to pay for the fuel and purchased power costs that are being incurred. The lack of incoming cash flow on a timely basis has resulted in diversion of funds from other purposes to pay fuel and purchased power costs.

An Uncollectibles Factor applicable to the FCA and PPCA rates would be an improvement to help avoid and mitigate such cash flow concerns. As discussed above in section V of our report, based on available information, we have recommended a Bad Debt Factor of 1.5% for purposes of calculating the base rate revenue requirement for permanent rates.³⁵ In order to accommodate having a similar Bad Debt Factor be applicable for the FCA and PPCA revenues going forward, commencing with the new FCA and PPCA rates that become effective after the date of new permanent rates, we recommend that a Bad Debt Factor also be applied to calculate those FCA and PPCA rates. In summary, we recommend that the Energy Bureau apply a Bad Debt Factor in the development of FCA and PPCA rates prospectively, starting in the first re-setting of those rates after the permanent base rate revenue requirement becomes effective.

IX. MAJOR STORMS RIDER AND EMERGENCY RESERVE ACCOUNT

A. Introduction

Extreme weather events and other natural disasters, including, but not limited to, hurricanes, high winds, severe storms, earthquakes, flooding, and wildfires, can cause outages and property damage.

In the past 10 years, several hurricanes have damaged Puerto Rico, including Hurricanes Irma and Maria in 2017 and Hurricane Fiona in 2022. Puerto Rico's location in the hurricane alley of the Caribbean makes improving electric system resiliency and recovering from storm damages a constant struggle. Hurricane Maria in 2017 was a category 5 storm when it hit the island. Its damage to the electric system caused one of the longest blackouts in U.S. history. Restoring power took nearly 11 months.

Puerto Rico has also experienced earthquakes. For example, in December 2019 earthquakes occurred on the southern side of the island. A 6.4 magnitude earthquake occurred on January 7, 2020, causing extensive damage and power outages, particularly in the southern region. The January 2020 earthquakes and aftershocks led to widespread damage to homes, infrastructure, and utility transmission and generation plant, including outages one of the island's

³⁵ The specific uncollectibles rate is subject to being refined if better information on Accounts Receivable collections, analysis of collectability of Accounts Receivable, write-offs of bad debts, and uncollectibles expense recorded in Account 904 becomes available. As of the date of our report, such information is being sought from LUMA.

major power plants. The December 2019/January 2020 earthquakes occurred while the Puerto Rico electric system was still undergoing recovery efforts from 2017 Hurricanes Irma and Maria.

B. Filing Requirements

On February 12, 2025, the PREB issued a Resolution and Order that established the filing requirements for LUMA's 2025 rate application. On February 27, 2025, the PREB issued another Resolution and Order, which established two additional filing requirements, including Schedule J, which relates to a major storm rider. On page 2 of the Resolution and Order, the PREB stated:

In Schedule J, LUMA shall provide language for, and an explanation of, a major-storm cost rider. As with the proposed revenue decoupling mechanism, LUMA's proposal should provide for an Energy Bureau opportunity to (a) review each initial proposal to adjust the rider, before the adjustment goes into effect; (b) at the end of each period in which the rider was in effect, perform a reconciliation if the adjustment's effects require one; and (c) review the mechanism itself before the start of FY 2027 and FY 2028.

In the rate proceeding, the Energy Bureau will consider these submissions and determine whether to reject them or adopt them (with or without modification).

As indicated by the above-noted filing requirements, the Energy Bureau required Applicants to provide language for a viable mechanism that will create and maintain a sufficient storm reserve, before and after the system causes major storm restoration costs. One mechanism used in other jurisdictions is a rider that collects from customers amounts for a reserve required by the electricity system to anticipate and address storm-caused outages.

C. Position of the Applicants

Currently, funding to address storm damage restoration is limited. LUMA witness Figueroa states that the LUMA T&D OMA dated June 22, 2020 requires PREPA to fund an Outage Reserve account for major outages at \$30 million, and to replenish this account each time those funds are spent. On page 75 of the Direct Testimony of Mr. Alejandro Figueroa, LUMA claims that PREPA has failed to replenish the Outage Reserve account by a total amount of \$239 million, including (1) approximately \$30 million to replenish the Outage Reserve account, and (2) approximately \$209 million to reimburse outage event costs which LUMA has had to cover from its operating account due to lack of available funds in the Outage Reserve account.

As noted in the above passage from the Energy Bureau's February 27, 2025 Resolution and Order, the PREB stated that with Schedule J from the filing requirements, LUMA shall provide language that discusses a major-storm cost rider. However, upon reviewing Schedule J from LUMA's rate application, Larkin noted that the Applicant's Schedule J merely referred to the Direct Testimony of Mr. Figueroa for a discussion of the proposed major storm rider.

On page 91 of his testimony, Mr. Figueroa states that LUMA agrees in principle with the concept of a major storm costs rider and that LUMA is proposing a tariff to be able to recover storm-related costs and replenish the Outage Event Reserve Account, subject to PREB

approval.³⁶ He states that by establishing a dedicated rider, LUMA aims to create a clear and consistent mechanism for recovering both past and future storm outage event costs. LUMA states that its proposed rider would ensure that funds used for emergency response are replenished without having to divert money from accounts designated for planned activities. LUMA states that this approach is intended to protect the utility's liquidity and financial stability by preventing the depletion of funds that were allocated for other essential operations.³⁷

With respect to its rate request, LUMA is seeking to recover approximately \$209 million over a two-year period to reimburse LUMA's Operating Account for Outage Event Costs that were paid from the Operating Account. The \$209 million represents expenditures incurred from December 2023 to February 2025.³⁸ LUMA is requesting to recover extraordinary costs that it had incurred to restore service to Puerto Rico following severe storm events.³⁹ LUMA also requests funding for the major outages reserve in its T&D OMA which specifies a balance of \$30 million and replenishing that balance back to the \$30 million amount if the reserve is drawn down for the purpose of paying for covered storm outage costs.

LUMA requests that its proposed Outage Recovery Rider be in the Energy Bureau's final Order. Based on LUMA's proposal, if approved by the PREB, the Rider would be in effect for the start of FY2027.⁴⁰

As for how the proposed Outage Recovery Rider would work, on pages 36-37 of his Direct Testimony, LUMA witness Mr. Sam Shannon states:

Unlike the other riders, the Outage Recovery Rider ("ORR") is not meant to cover normal operation and maintenance expenses. We propose that the Energy Bureau authorize the creation of a rider, with the amount set to zero for the 2026 test year. As storms or other natural disasters occur and LUMA incurs expense related to these storms and natural disasters, LUMA will file a request with the Energy Bureau to use the Outage Recovery Rider to replenish the reserve account and cover expenses for storms and disasters that exceed the reserve account balance. The rider will only operate for a limited amount of time set by the Energy Bureau to recover the authorized funding. Once the time has expired, the rider will be set back to zero.

Mr. Shannon states that LUMA proposes that the ORR use an energy charge to recover costs from each customer class and he also recommends that the proposed ORR be a non-bypassable charge for NEM customers so that they also share the costs for storm recovery.

D. Energy Bureau Treatment For Provisional Rates

With respect to LUMA's application for provisional rates, the PREB addressed this issue in its Resolution and Order dated July 31, 2025. Page 13 of that Resolution and Order

³⁶ As discussed in Exhibit 20.0, Sam Shannon's Direct Testimony from LUMA's rate case filing, LUMA's proposed storm cost rider is called the Outage Recovery Rider.

³⁷ Exhibit 1.0, Alejandro Figueroa's Direct Testimony from LUMA's rate case filing

³⁸ Exhibit 1.0, Alejandro Figueroa's Direct Testimony, Exhibit 1.05 and Exhibit 1.06 from LUMA's rate case filing

³⁹ LUMA response to PREPA-of-LUMA-PROV-34

⁴⁰ Exhibit 1.0, Alejandro Figueroa's Direct Testimony from LUMA's rate case filing

states that LUMA and Genera requested \$120 million and \$30 million, respectively, to fund Outage Reserve accounts. However, the PREB rejected LUMA's and Genera's requests for funding the Outage Reserve accounts and instead established a system-wide Emergency Reserve Account for \$20 million. Specifically, on pages 37-38 of that Resolution and Order, the PREB stated:

The Energy Bureau **ESTABLISHES** a single system-wide Emergency Reserve Account (ERA) funded at \$20 million. The ERA is a restricted account: withdrawals require prior, case-specific authorization by the Energy Bureau.

To ensure the proper and transparent implementation of the System-Wide Emergency Reserve Account, the Energy Bureau further **ORDERS** that:

- **Account Establishment:** PREPA shall establish a new, separate, and segregated account (the "Account") with an initial balance of \$20 million within sixty (60) days from the issuance of this resolution and order. PREPA shall submit proof of the Account's creation and funding to the Energy Bureau.
- **Account Administration:** The Account shall be held in trust, and PREPA shall act as the administrator, responsible for maintaining the account but not for authorizing withdrawals.
- **Withdrawing Protocol:** To request funds, LUMA, Genera or PREPA must file a petition with the Energy Bureau. The petition must include, at a minimum: (i) a full description of the emergency event, (ii) a detailed, itemized estimate of the required funds, and (iii) a sworn statement certifying that the costs cannot be covered by the petitioner's approved operational budget.

E. Illustration of Another Electric Utility's Storm Cost Recovery Charge

Like Puerto Rico, Florida is also subject to devastating extreme weather events, such as major hurricanes. The Florida Public Service Commission ("FPSC") has established Storm Cost Recovery Charges to recover storm costs and to replenish utility storm recovery reserves.

In PC Ex. 62.05, we present an FPSC Order PSC-2024-0503-PCO-EI dated December 17, 2024 Approving Florida Power & Light Company's ("FPL") Interim Storm Cost Recovery Charge, in FPSC Docket No. 20240149-EI.

To illustrate how the Storm Cost Recovery charge application and recovery process works before the FPSC, we reference PC Ex. 62.05. Basically, on October 29, 2024, FPL filed a petition for a limited proceeding seeking authority to implement an Interim Storm Restoration Recovery Charge to recover \$1.2 billion for the incremental restoration costs related to Hurricanes Debby, Helene, and Milton (collectively, "the Storms"), as well as the replenishment of its retail storm reserve up to \$150 million.

In its petition, FPL stated that it had incurred approximate recoverable costs in the amount of \$113.5 million for Hurricane Debby, \$157.8 million for Hurricane Helene, and \$811.1 million for Hurricane Milton. The Company further stated that all amounts were calculated in

accordance with the Incremental Cost and Capitalization Approach methodology prescribed in Rule 25-6.0143, Florida Administrative Code.

In Florida, the approval of a utility's Interim Storm Restoration Recovery Charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, will be considered by us at a later date.

The Interim Storm Restoration Recovery Charge covers

Restoration costs: The surcharge helps recover the costs of repairing electrical infrastructure damaged by 2024's Hurricanes Debby, Helene, and Milton.

Replenishing reserves: FPL is also using a portion of the funds to restore its storm reserve fund to \$150 million. This fund was depleted by 2023's Hurricane Idalia and 2024's Hurricane Debby.

The Interim Storm Restoration Recovery Charge has these features:

It is Temporary: The interim storm restoration surcharge is temporary and was implemented for FPL for the 12-month period from January 1 through December 31, 2025.

It requires Commission approval: As a regulated utility, FPL must file requests with the FPSC to recover storm-related costs. The FPSC reviews the requests, holds public hearings, and ultimately decides on the amount and duration of the surcharges.

It is subject to Periodic Adjustments: Storm cost recovery is subject to true-up filings, which compare actual costs to recovered amounts and can lead to rate adjustments.

The storm costs being recovered are not in base rates: These types of temporary charges are not included in the utility's standard "base rates." Instead, they appear as a separate line item on the bill to recover the extraordinary and unpredictable costs associated with major weather events, such as hurricanes.

F. Recommendation

As noted above, in its Resolution and Order on Provisional Rates, the Energy Bureau established a single, system-wide Emergency Reserve Account initially funded at \$20 million.⁴¹

There should be a clear way of providing for a means of requesting replenishments of that account and for funding restoration costs associated with future extreme weather events. We recommend that the Energy Bureau add a means of requesting additional funding to be submitted by Applicants in the event of additional severe weather events, such as hurricanes cause damages to the Puerto Rico electric system. We recommend that the process for requesting additional

⁴¹ See, e.g., pages 13 and 37 of the Energy Bureau's July 31, 2025 Resolution and Order for FY 2026 Provisional Rates and FY 2026 Provisional Budget.

funding by Applicants include the following features (similar to the Florida Interim Storm Restoration Recovery Charge features noted above):

Restoration costs: The surcharge would recover the costs of repairing electrical infrastructure damaged by Hurricanes.

Replenishing reserves: If the fund drops below zero, a portion of the funds will be used to restore the system-wide Emergency Reserve Fund to \$20 million.

We also recommend that the filings by Applicants to replenish the Emergency Reserve Account and the related Surcharge to recovery such costs be subject to the following regulatory safeguard provisions:

- **The Surcharge is Temporary:** The surcharge to recover storm restoration costs and to replenish the Emergency Reserve be temporary and that the related recovery period be specified to be a fiscal year or some other period to be determined by the Energy Bureau.
- **It requires Energy Bureau approval:** The requests to be submitted by Applicants will be reviewed by the Energy Bureau and addressed in public hearings. Ultimately, the Energy Bureau will decide on the amount and duration of the surcharges.
- **It is subject to Periodic Adjustments:** Storm cost recovery is subject to true-up filings, which compare actual costs to recovered amounts. Differences between actual approved amounts and Applicants requested amounts can lead to rate adjustments.
- **The storm costs being recovered are not in base rates:** The temporary charges for storm cost recovery and to replenish the reserve will not be included in the utility's standard "base rates." Instead, they will appear as a separate line item on the bill to recover the extraordinary and unpredictable costs associated with major weather events, such as hurricanes.

We also recommend that the Applicants' actual storm recovery costs be subjected to a regulatory audit and that refunds of the surcharged amounts be made if imprudent or unreasonable spending is discovered.

X. RECONCILIATION OF PERMANENT AND PROVISIONAL RATES

By Order issued July 31, 2025, the Commission approved fiscal year 2026 provisional rates and a fiscal year 2026 provisional rates budget for PREPA.

There is a requirement under the Commission's Rate Case Filing Rules and under Act 57-2017 that a reconciliation of the Commission approved permanent and provisional rates occur. The Commission's Rate Case Filing Rules at Section 2.02, Request for Provisional Rates, state that:

Pursuant to Article 6.25(e) of Act 57-2014 and Section 6A(f) of Act 83-1941, when issuing a final order establishing permanent rates, the Commission shall order PREPA to adjust its customer's bills in order to credit or collect any difference between (a) the

Provisional Rate charged by PREPA during the time period in which such Provisional Rate remained in effect and (b) the permanent rate which the Commission determines should have applied during such time period, so as to ensure that the Provisional Rates were just and reasonable. Such order shall reflect any upward or downward adjustment, effective as of the date the Provisional Rates were established, necessary to ensure the Provisional Rates were just and reasonable.

Section 2.02(C) of the Rules provide as follows:

Pursuant to Article 6.25(d) of Act 57-2014 and Section 6A(e) of Act 83-1941, when filing a formal application for rate review, PREPA may include a request for the Commission to establish Provisional Rates. The Commission will not address any request for Provisional Rates made on any date after the date a formal application for rate review is filed. The application for Provisional Rates must be clearly marked as such and must include the following elements:

C) It shall include a mechanism for tracking any increase or decrease resulting from the Provisional Rates, so as to ensure compliance with Article 6.25(e) of Act 57-2014 and Section 6A(f) of Act 83-1941 (which require PREPA to credit or collect any difference between the Provisional Rate and the permanent rate established by the Commission accrued during the term in which the Provisional Rate remained in effect).

If the PREB determines that PREPA's base rate revenue requirement for permanent rates is lower than the amount PREPA has been recovering through the provisional rates, that reduction is retroactive back to the date on which PREPA started collecting the higher rate. PREPA therefore will need to return to ratepayers the excess over some period of time.

The increase in rates authorized by the PREB's July 31, 2025 Order Establishing Provisional Rates was put into effect on a cents/kWh basis. To facilitate reconciliations, the Provisional Rates included two surcharge components (riders), one for pension costs and the other for costs other than pensions:

Rider for all costs other than pension costs:	\$0.014931/kWh

Rider for pension costs:	\$0.019191/kWh

The permanent rates may be impacted by rate design recommendations being made by Applicants and by the PREB's rate design consultant Zachary Ming.

Discussions were had with LUMA at public technical conferences about how LUMA could comply with the requirement to track the increase resulting from the Provisional Rates, so as to ensure compliance with Article 6.25(e) of Act 57-2014 and Section 6A(f) of Act 83-1941 (which require PREPA to credit or collect any difference between the Provisional Rate).

In those discussions, LUMA indicated it could reconcile on a per-customer basis if necessary. Reconciliation of provisional and permanent rates on a per-rate class basis or per-customer basis would be possible using its customer billing system but could take an extended time.

Recommendation:

The reconciliation of provisional and permanent base rates should include the following components:

- 1) Variances between budget amounts approved by the Energy Bureau for permanent rates and the corresponding amounts that were approved by the Energy Bureau for provisional rates for LUMA, Genera and PREPA. Because the provisional rate revenue requirement was approved by the Energy Bureau on the basis of reviewing and approving specific budget components, which are detailed in the Bureau's July 31, 2025 Resolution and Order, Applicants' spending during fiscal year 2026 under each category, as well as in total by each firm, LUMA, Genera and PREPA, respectively, should be tracked and made available for reconciliation.
- 2) Variances between budgeted federally funded capital expenditures and actual capital expenditures and the actual amounts of federal funding related to such projects. This needs to be a component of the reconciliation because if budgeted federal funding does not occur as projected (a) either the projects will not get funded and built or (b) another source of funds (e.g., additional revenues from ratepayers) will need to be identified to pay for the capital expenditures.
- 3) Variations between provisional rate revenues billed to customers for fiscal year 2026 and the revenue requirement approved by the Energy Bureau for provisional rates.
- 4) Variations in any other not yet identified factors, such as funding that may become available from the Puerto Rico government for the electric system which could mitigate some of the need for ratepayer funding of the permanent rates revenue requirement, will need to be taken into account in performing a reconciliation of revenue requirements for permanent and provisional base rates.

As noted above, the Energy Bureau established the Provisional Rates with two components:

Rider for all costs other than pension costs: \$0.014931/kWh

Rider for pension costs: \$0.019191/kWh

We recommend that the Energy Bureau require LUMA to separately track the revenue that is being billed to customers from each component. By having the two components identified separately, each with its own per-kWh rate, LUMA's accounting and customer billing systems should be able to do this tracking accurately. LUMA should continue to inform the Energy Bureau if problems are encountered that will impair such tracking.

We recommend that the Energy Bureau require PREPA report on the amounts of funding being submitted for pensions, and also to report on amounts of pension funding and other electric system funding from sources other than ratepayers, if such alternative funding sources become available.

Further, other factors can affect whether an approved base rate revenue requirement is actually collected. Factors causing variability between approved and billed revenue requirements include (1) variations between billed kWh sales and forecasted kWh sales, (2) variances in the number of customers in each rate class between actual and forecasted, and (3)

variances between budgeted and actual costs. We therefore recommend (1) that LUMA track variations between billed kWh sales and budgeted/forecast kWh sales, (2) that LUMA track variances in the number of customers in each rate class between actual and forecasted; and (3) that LUMA, Genera and PREPA track variances between budgeted and actual costs.

Additionally, because uncollectibles are a component of the base rate revenue requirement, LUMA should also track and be able to report amounts that it is recording in Account 904, Uncollectible Accounts Expense.

LUMA should be required to assemble and present a detailed analysis of all of the significant causes of variations between approved provisional rates and the amounts billed to customers for the provisional base rates.

XI. SUMMARY OF FINDINGS AND RECOMMENDATIONS

A. Revenue Requirement Methodology Recommendations

We recommend that the Commission utilize the Modified DSCR ratemaking model for purposes of determining PREPA's base rate revenue requirement for permanent rates in the current rate case. We note that the debt service portion may have to be temporarily set at zero, in recognition that no principal or interest payments are being made on PREPA's legacy debt. Once the Title III Court resolves the issues of responsibility for PREPA's legacy debt and if PREPA is able to access new debt financing to finance CapEx or other system needs, inclusion of a debt service component and appropriate coverage ratio in the revenue requirement formula would be necessary and appropriate.

We note that the Applicants have used a variation of the Modified DSCR methodology for their proposed FY 2026 revenue requirements, which are based on their requested FY 2026 optimal and constrained budget costs. Applicants have included a calculation of debt service costs and a "margin" amount. Those aspects are separately addressed in our report.

Once PREPA is able to issue additional long-term debt at reasonable costs, the Modified DSCR should no longer be employed for ratemaking purposes. Ratepayers should be relieved of the aspect of providing annual dollar-for-dollar financing of PREPA's capital expenditures. Once access to financial markets is restored and PREPA can issue debt at reasonable costs to finance capital expenditures, PREPA should finance the system's capital needs beyond the internally generated cash flow being collected through revenue for electric service.

B. Bad Debt Expense Recommendations

Based on currently available information, we recommend that the Energy Bureau use an uncollectible rate of 1.5% for calculations in the base rate revenue requirement. If better information becomes available, the uncollectibles rate to be used should incorporate consideration of such additional information.⁴²

⁴² Additional information on collections of billed revenue, analysis of the collectability of amounts in Accounts Receivable and uncollectibles recorded by LUMA in Account 904, Uncollectible Accounts Expense, is being sought.

We also recommend that, effective with quarterly factor filings that occur after the Energy Bureau's final decision on base rates in the current proceeding, that the Energy Bureau include a similar uncollectible factor in the calculation of the FCA and PPCA rates. The inclusion of a provision for uncollectibles in the FCA and PPCA rates will help address concerns regarding inadequate system cash flow issues related to the undercollection of FCA and PPCA revenues due to customers not paying the billed amounts for electric service.

C. Legacy Debt and Debt Service Recommendations

The Applicants' presentation has included estimated amounts for the Energy Bureau's consideration for a Legacy Debt Obligation, which are available if the Energy Bureau wishes to use a non-zero amount. Concerning the Applicants' proposed inclusion of Debt Service in the base rate revenue requirement for FY 2026, we recommend that those amounts be excluded until there is a resolution of PREPA's Legacy Debt Obligation by the Title III Court. Currently, due to the Title III bankruptcy Court stay, no payments of principal or interest on the legacy debt are being made. We recommend against using a "guesstimate" of an amount for the Legacy Debt Obligation for the FY 2026 revenue requirement. We recommend waiting for a final decision from the Title III Court before any amounts for a Legacy Debt Obligation are included in the revenue requirement.

We urge heightened caution by the Energy Bureau in addressing amounts for a Legacy Debt Obligation, and advise and recommend that the Energy Bureau not "front run" the Title III Court in identifying a non-zero amount for inclusion in the revenue requirement for FY 2026. In our professional judgment, the most prudent course of action for the Energy Bureau would be to simply await the determination of the Title III Court on what the Legacy Debt Obligation is, and once that is known, to then proceed with designing a revenue requirement and a related recovery mechanism to address the collection of that amount from ratepayers.

Concerning the development of a Legacy Debt Rider surcharge, we recommend that be deferred until there is a resolution of PREPA's Legacy Debt Obligation by the Title III Court. If such a final determination has been obtained, the development of an appropriate method of charging such amounts to ratepayers, such as in a Rider, can be determined as an element of rate design.

Concerning ideas on how an amount for a Legacy Debt Obligation could be reconciled, we offer the following ideas for the Energy Bureau's consideration. If the collection of such an amount from ratepayers is exclusively prospective and the collection can be accomplished in a separate Rider, keeping the revenue requirement associated with this separate from the other components of the FY 2026 budgets that are being reviewed and analyzed by the Energy Bureau could avoid having to make a potentially complicated reconciliation for the impact of a Legacy Debt Obligation on fiscal year 2026 results. A combination of the following components of ratemaking treatment to provide rate recovery could help avoid complications associated with a reconciliation that might be present if an alternative ratemaking treatment were to be used: (1) treating the Legacy Debt Obligation as a separate component of the revenue requirement once it is known from a Title III Court decision, (2) placing recovery of that into a Legacy Debt Rider, and (3) treating it as an item for prospective revenue requirement collection only (i.e., not attempting to reconcile any related amounts back to July 1, 2025 or to fiscal year 2026 results).

D. “Margin” Recommendations

Inclusion of “Margin” in a utility’s revenue requirement can be appropriate in many circumstances. Margin essentially provides a “cushion” to the utility by providing additional revenues that are beyond the specifically approved operating expenses and ratepayer-funded capital expenditure amounts. The extra amount represented by the Margin helps the utility address and manage unanticipated fluctuations in revenue or costs that can occur.

One of the alternative ways of addressing “Margin”, as noted in the definition, is as an Operating Reserve. An illustration of how that alternative could be calculated is described in our report in section VI. Because of the way the revenue requirements are being developed in the current rate case by the detailed review of the Applicants’ optimal and constrained budgets, in our judgment, a separate Margin amount is not needed. Nor is there currently a sufficiently clear basis for calculating one using an Operating Reserve method.

The collections of the related revenue for Margin by the utility as part of its overall base rate revenue collection could be used to accumulate an equity balance (or to reduce a deficit that had been accumulated from prior years). Additional funding beyond amounts approved for specifically budgeted operating expenses or for specifically budgeted capital expenditures to be funded by ratepayers during the current year could also be used to pay for capital expenditures that are not being funded by other sources. In the current rate case, the Applicants’ proposed operating costs and capital expenditures are being reviewed in detail. Moreover, approved budgets for capital expenditures beyond those that are expected to be covered by federal funding, under the ratemaking methodology being used in this rate case will be borne by ratepayers on a dollar-for-dollar basis for the FY 2026 revenue requirement as will Energy Bureau approved amounts for operations, maintenance and other expenses. Given those circumstances, we recommend against charging ratepayers for an additional amount of “Margin” for the FY 2026 revenue requirement. Accordingly, we are not recommending that an amount for “Margin” be included in the FY 2026 revenue requirement.

Concerning the amount of “Margin” to be included in the revenue requirement, we recommend that such amount not be based on estimates of PREPA’s Legacy Debt Obligation as Applicants have proposed. In this respect, we agree with Bondholders witness Tierney that the Margin amount should not be based on PREPA’s Legacy Debt Obligation or tied to uncertain or speculative future financing needs.

If new sources of financing become available for access by PREPA during the remainder of FY 2026, or during FY 2027 or FY 2028, the terms of that financing, once they are known, can be used at that time to prospectively determine a Debt Service Coverage-based Margin amount. However, no information on new financing was included by Applicants, and such information is not known. As noted above, Applicants’ proposed Margin amounts were based exclusively on Legacy Debt, not on any of the other alternative calculations.

In the future, as the Puerto Rico electric system moves away from dollar-for-dollar funding by ratepayers of capital projects in the year in which such expenditures are made, the calculation of a Margin amount to include in future revenue requirements deserves reconsideration.

E. Subsidies and CILT Recommendations

The CILTA, SUBA-HH, SUBA-NHH and EE rates in effect as of July 1, 2025, i.e., for FY 2026, have already been set by the PREB outside of the base rate revenue requirement process in the current rate case. Consequently, the revenues being collected for those elements will be at the rates approved by the PREB rather than at the rates that were assumed by LUMA when Applicants filed their revenue requirement application. The annual subsidy factors include a provision for reconciliation and true-up. Unless the related rate design is changed, there may be no impact from these factors on the base rate revenue requirement for FY 2026. The PREB's rate design consultant, Zachary Ming, is addressing a rate design issue of whether exclusively kWh-based charges continue to be how these subsidies should be recovered from ratepayers or whether requiring that a portion of the revenue requirement for these subsidies be prospectively charged on some basis other than electric sales (i.e., on a per-kWh basis), such as a monthly charge.

We also recommend that the Energy Bureau seek input from its legal advisors concerning to which components of the subsidies, if any, the PREB can apply discretion, versus which components are statutorily mandated.

OIPC has raised issues concerning whether PREPA has responsibility to seek reimbursement of Irrigation District Subsidy amounts from the Government of Puerto Rico, whether PREPA has been diligent in those efforts, and whether costs of the Irrigation District Subsidy should be assigned for recovery to a particular rate class, rather than simply being a component of the SUBA-NHH annual factor rate, which is charged to electric system ratepayers on a per-kWh basis. Because the resolution of these concerns appears to depend on legal analysis, which we are not providing, we recommend that the Energy Bureau seek and receive advice from its legal advisors.

F. Fuel and Purchased Power Rates Recommendations

An Uncollectibles Factor applicable to the FCA and PPCA rates would be an improvement to help avoid and mitigate cash flow concerns relating to customer non-payment of billed FCA and PPCA rates. As discussed above in section VIII of our report, we recommend that a Bad Debt Factor be applied in the development of FCA and PPCA rates prospectively, starting in the first re-setting of those rates after the permanent base rate revenue requirement becomes effective.

G. Major Storms Rider and Emergency Reserve Account Recommendations

In its July 31, 2025 Resolution and Order on Provisional Rates, the Energy Bureau established a single, system-wide Emergency Reserve Account initially funded at \$20 million.

There should be a procedure for requesting replenishments of that account and for funding restoration costs associated with future extreme weather events, such as hurricane damages. We recommend that the Energy Bureau add a means of requesting additional funding to be submitted by Applicants in the event of additional severe weather events, such as hurricanes, cause damages to the Puerto Rico electric system. We recommend that the process

for requesting additional funding by Applicants include the following features (similar to the Florida Interim Storm Restoration Recovery Charge features noted above):

Restoration costs: The surcharge would recover the costs of repairing electrical infrastructure damaged by Hurricanes.

Replenishing reserves: If the fund drops below zero, a portion of the funds will be used to restore its Emergency Reserve Fund to \$20 million.

We also recommend that the filings by Applicants to replenish the Emergency Reserve Account and the related Surcharge to recovery such costs be subject to the following regulatory safeguard provisions:

The Surcharge is Temporary: The surcharge to recover storm restoration costs and to replenish the Emergency Reserve be temporary and that the related recovery period be specified to be a fiscal year or some other period to be determined by the Energy Bureau.

It requires Energy Bureau approval: The requests to be submitted by Applicants will be reviewed by the Energy Bureau and addressed in public hearings. Ultimately, the Energy Bureau will decide on the amount and duration of the surcharges.

It is subject to Periodic Adjustments: Storm cost recovery is subject to true-up filings, which compare actual costs to recovered amounts. Differences between actual approved amounts and Applicants requested amounts can lead to rate adjustments.

The storm costs being recovered are not in base rates: The temporary charges for storm cost recovery and to replenish the reserve will not be included in the utility's standard "base rates." Instead, they will appear as a separate line item on the bill to recover the extraordinary and unpredictable costs associated with major weather events, such as hurricanes.

The storm costs are subject to regulatory audit. We also recommend that the Applicants' actual storm recovery costs be subjected to a regulatory audit and that refunds of the surcharged amounts be made if imprudent or unreasonable spending is discovered.

H. Reconciliation of Permanent and Provisional Rates Recommendations

The reconciliation of provisional and permanent base rates should include the following components:

- 1) Variances between budget amounts approved by the Energy Bureau for permanent rates and the corresponding amounts that were approved by the Energy Bureau for provisional rates for LUMA, Genera and PREPA
- 2) Variances between budgeted federally funded capital expenditures and actual capital expenditures and the actual amounts of federal funding related to such projects
- 3) Variations between provisional rate revenues billed to customers for fiscal year 2026 and the revenue requirement approved by the Energy Bureau for provisional rates.
- 4) Variations in any other not yet identified factors that will need to be taken into account in performing a reconciliation of revenue requirements for permanent and provisional base rates

As noted above, the Energy Bureau established the Provisional Rates with two components:

Rider for all costs other than pension costs: \$0.014931/kWh

Rider for pension costs: \$0.019191/kWh

We recommend that LUMA be required to separately track the revenue that is being billed to customers from each component. By having the two components identified separately, each with its own per-kWh rate, LUMA's accounting and customer billing systems should be able to do this tracking accurately. LUMA should continue to inform the Energy Bureau if problems are encountered that will impair such tracking.

We recommend that PREPA report on the amounts of being paid for pensions, and also to report on amounts of pension funding from sources other than ratepayers, if such alternative funding sources become available.

Additionally, because the provisional rate revenue requirement was approved by the Energy Bureau on the basis of reviewing and approving specific budget components, which are detailed in the Bureau's July 31, 2025 Resolution and Order, Applicants' spending during fiscal year 2026 under each category, as well as in total by each firm, LUMA, Genera and PREPA, respectively, should be tracked and made available for reconciliation.

Further, other factors can affect whether an approved base rate revenue requirement is actually collected. Factors causing variability between approved and billed revenue requirements include (1) variations between billed kWh sales and budgeted/forecast kWh sales, (2) variances in the number of customers in each rate class between actual and forecasted, and (3) variances between budgeted and actual costs. We therefore recommend that (1) LUMA track variations between billed kWh sales and budgeted/forecast kWh sales, (2) LUMA track variances in the number of customers in each rate class between actual and forecasted, and (3) that LUMA, Genera and PREPA track variances between budgeted and actual costs.

Additionally, because uncollectibles are a component of the base rate revenue requirement, LUMA should also track and be able to report amounts that it is recording in Account 904, Uncollectible Accounts Expense.

LUMA should be required to assemble and present a detailed analysis of all of the significant causes of variations between approved provisional rates and the amounts billed to customers for the provisional base rates.

XII. CERTIFICATION

By filing this report, we certified that the information, facts, schedules, exhibits and analysis provided here is our direct testimony and, to the best of our knowledge, true and correct.

Dated: October 6, 2025 at Livonia, Michigan.



Ralph C. Smith
Senior Regulatory Consultant
Larkin & Associates PLLC



Mark S. Dady
Regulatory Consultant
Larkin & Associates PLLC

XIII. APPENDIX I - RECONCILIATION OF APPLICANTS' UPDATED REVENUE REQUIREMENT WITH THEIR JULY 3, 2025 FILING AMOUNTS

In its initial filing made on July 3, 2025, in its Optimal budget for FY2026, LUMA requested \$933,333,656 in annual non-federally funded capital expenditures and \$4,361,846,211 in annual operating expense for an overall revenue requirement of \$5,295,179,867. For FY2027, LUMA requested \$1,115,308,341 in annual non-federally funded capital expenditures and \$4,351,647,506 in annual operating expense for an overall revenue requirement of \$5,466,955,847. For FY2028, LUMA requested \$1,270,516,525 in annual non-federally funded capital expenditures and \$4,310,951,877 in annual operating expense for an overall revenue requirement of \$5,581,468,402.

In its initial filing made on July 3, 2025, in its Constrained budget for FY2026, LUMA requested \$638,277,486 in annual non-federally funded capital expenditures and \$4,030,025,086 in annual operating expense for an overall revenue requirement of \$4,669,025,586. For FY2027, LUMA requested \$713,671,354 in annual non-federally funded capital expenditures and \$4,055,849,279 in annual operating expense for an overall revenue requirement of \$4,769,520,633. For FY2028, LUMA requested \$814,829,188 in annual non-federally funded capital expenditures and \$3,982,298,843 in annual operating expense for an overall revenue requirement of \$4,797,128,031.

On August 15, 2025, Larkin issued ROI PC-of-LUMA-FIN-2 to LUMA⁴³ which requested that as the Company discovers errors in its initial filing made on July 3, 2025, to (1) identify and explain such errors, (2) how the errors are being corrected, and (3) to provide the related documentation to support any changes to the Company's filing.⁴⁴ On August 22, 2025, the Hearing Examiner informed the parties of his intent to schedule a technical conference between August 27th and 29th to discuss the revenue requirement numbers. LUMA informed the Hearing Examiner, Mr. Scott Hempling, that to it required until August 28, 2025, to file updated or revised revenue requirement numbers. On that same date, the Hearing Examiner acknowledged LUMA's request and invited confirmation that LUMA's plan was to file consolidated and updated revenue requirement numbers with supporting unlocked spreadsheets.

On August 29, 2025, LUMA provided an updated response to PC-of-LUMA-FIN-2, which included PC-of-LUMA-FIN-2 Attachment 1. This attachment contains updates to LUMA's Schedule C-2 Optimal and Schedule C-2 Constrained and reflects the adjustments to the revenue requirement for LUMA, Genera and PREPA for each fiscal year of the rate period. LUMA stated that updated Schedule C-2 (Optimal and Constrained) summarizes the revenue requirement in its entirety. LUMA also stated that it will continue to update the response to PC-of-LUMA-FIN-2 as additional errors and/or omissions are discovered.

Table 4, below, starts with LUMA's initial revenue requirements for FY2026, FY2027 and FY2028 that were filed on July 3, 2025 and lists out the reconciling items reflecting the

⁴³ Copies of referenced ROIs are included with our report in PC Ex. 62.06 and PC Ex. 62.07.

⁴⁴ Similar ROI's were issued to Genera and PREPA, including PC-of-Genera-FIN-4 and PC-of-PREPA-FIN-5.

differences between the as-filed Optimal budget and the updated revenue requirement as of August 29, 2025:

Table 4: Reconciliation from LUMA’s Initial Revenue Requirement to its Updated Revenue Requirement for FY2026, FY2027 and FY2028 (Optimal):

Description	FY2026	FY2027	FY2028
July 3rd Total O&M	\$ 5,295,179,867	\$ 5,466,955,847	\$ 5,581,468,402
PREPA Placeholder	\$ (87,760,970)	\$ (111,127,677)	\$ (117,367,377)
PREPA Revenue Requirement	\$ 91,870,573	\$ 81,357,353	\$ 79,009,017
PREPA Pension	\$ 307,475,422	\$ 298,658,581	\$ 298,438,608
Genera Addition	\$ -	\$ 1,000,000	\$ 1,000,000
Formula Error Re: Genera Reserve	\$ -	\$ 30,000,000	\$ 30,000,000
LUMA Adjustments	\$ (150,000)	\$ -	\$ -
FOMB Advisory	\$ 18,324,982	\$ 5,866,071	\$ 9,197,272
LUMA Interim	\$ 8,750,000	\$ 6,562,500	\$ 4,375,000
Updated Revenue Requirement	\$ 5,633,689,875	\$ 5,779,272,674	\$ 5,886,120,921
Source: PC-of LUMA-FIN-2			

As shown in the above table, after reflecting the corrections and/or updates to LUMA’s initial filing, the Company’s updated proposed Optimal revenue requirements are \$5,633,689,875 for FY2026, \$5,779,272,674 for FY2027, and \$5,886,120,921 for FY2028.

Table 5, shown below, presents similar information showing the reconciliation submitted by LUMA for the constrained budget amounts:

Table 5: Reconciliation from LUMA’s Initial Revenue Requirement to its Updated Revenue Requirement for FY2026, FY2027 and FY2028 (Constrained):

Description	FY2026	FY2027	FY2028
July 3rd Total O&M	\$ 4,669,025,586	\$ 4,769,520,633	\$ 4,797,128,031
PREPA Placeholder	\$ (78,470,749)	\$ (79,876,521)	\$ (83,459,839)
PREPA Revenue Requirement	\$ 91,870,573	\$ 81,357,353	\$ 79,009,017
PREPA Pension	\$ 307,475,422	\$ 298,658,581	\$ 298,438,608
Genera Addition	\$ 1,000,000	\$ 1,000,000	\$ 1,000,000
LUMA Adjustments	\$ (100,000)	\$ (165,935)	\$ (172,575)
FOMB Advisory	\$ 18,324,982	\$ 5,866,071	\$ 9,197,272
LUMA Interim	\$ 8,750,000	\$ 6,562,500	\$ 4,375,000
Updated Revenue Requirement	\$ 5,017,875,815	\$ 5,082,922,682	\$ 5,105,515,514
Source: PC-of LUMA-FIN-2			

As shown in the above Table 5, after reflecting the corrections and/or updates to LUMA’s initial filing, the Company’s updated proposed Constrained revenue requirements are \$5,017,875,815 for FY2026, \$5,082,922,682 for FY2027, and \$5,105,515,514 for FY2028.

The response to PC-of-LUMA-FIN-2 included explanations of the updates made to LUMA's initial filing as well as providing references to where those updates are reflected in Attachment 1 to PC-of-LUMA-FIN-2 (i.e., LUMA's updated revenue requirement).

As it related to corrections and/or updates to Genera's and PREPA's initial filing schedules, Larkin issued PC-of-LUMA-FIN-3, which asked whether LUMA incorporated any revisions or updates that were provided by Genera and/or PREPA subsequent to the July 3, 2025 filing date and to identify and explain any such changes, and to provide supporting documentation. In its response to PC-of-LUMA-FIN-3, LUMA stated that Genera's and PREPA's updates have been incorporated into PC-of-LUMA-FIN-2, Attachment 1.

The response to PC-of-LUMA-FIN-2 provided explanations for the updates shown on PC-of-LUMA-FIN-2, Attachment 1, which are replicated in Table 6 below:

Table 6: Explanations of LUMA's Updates to Revenue Requirement

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
C-2 Reference	Line Item Reference(s)	Applicable Fiscal Year	Description	July 3 Filing Amount	Adjustment	Updated Amount	Reason for Change
C-2 Optimal & C-2 Constrained	42	2026	FOMB Advisor Costs	\$32,964,202	\$18,324,982	\$51,289,184	Inadvertent error in July 3rd filing. This number was provided by the FOMB. See NPFGC-of-LUMA-PROV-19 for details.
C-2 Optimal & C-2 Constrained	41	2026	LUMA Interim Costs	\$18,700,000	\$8,750,000	\$27,450,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed. See NPFGC-of-LUMA-PROV-19 for details.
C-2 Optimal & C-2 Constrained	42	2027	FOMB Advisor Costs	\$19,778,521	\$5,866,071	\$25,644,592	Inadvertent error in July 3rd filing.
C-2 Optimal & C-2 Constrained	41	2027	LUMA Interim Costs	\$11,150,000	\$6,562,500	\$17,712,500	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
C-2 Optimal & C-2 Constrained	42	2028	FOMB Advisor Costs	\$8,241,051	\$9,197,272	\$17,438,323	Inadvertent error in July 3rd filing.

C-2 Optimal & C-2 Constrained	41	2028	LUMA Interim Costs	\$7,050,000	\$4,375,000	\$11,425,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
C-2 Optimal & C-2 Constrained	7	2026	Other Income	\$56,501,061	\$27,903,135	\$84,404,196	Inadvertent error in July 3 rd filing. <i>Other Income</i> has been standardized to the number used in the Energy Bureau's July 31 st Provisional Rate Order.
C-2 Optimal & C-2 Constrained	7	2027	Other Income	\$56,695,461	\$30,646,002	\$87,341,462	Inadvertent error in July 3 rd filing. This number is based on the FY2026 forecast, inflated by 3.48%.
C-2 Optimal & C-2 Constrained	7	2028	Other Income	\$56,370,898	\$34,010,047	\$90,380,94	Inadvertent error in July 3 rd filing. This number is based on the FY2027 forecast, inflated by 3.48%.
C-2 Constrained	60	FY2027	Non Federally Funded Capital	\$165,935	(\$165,935)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
C-2 Constrained	60	FY2028	Non Federally Funded Capital	\$172,575	(\$172,575)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
C-2 Optimal	35	FY2026	Professional & Technical Services	\$8,085,000	(\$150,000)	\$7,935,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.
C-2 Constrained	35	FY2026	Professional & Technical Services	\$5,785,000	(\$100,000)	\$5,685,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.

Using the references shown in column B of the above table, Larkin tied each of the adjustments shown in column F to PC-of-LUMA-FIN-2, Attachment 1.

PC Ex. 62.01

Qualifications of Ralph C. Smith

PC Ex. 62.01
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, Barbados, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
&76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA	
& 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001	
& ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
U-87-47	Anchorage Water and Wastewater Utility (Alaska PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	
& E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R-901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
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7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
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U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
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U-1514-93-169/	
E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
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95-03-01	Southern New England Telephone Company (Connecticut PUC)
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06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
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E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
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11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
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11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)
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12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
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12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
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14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
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R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
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A.14-11-003 U-14-111 2015-UN-049 15-0003-G-42T PUE-2015-00027 Docket No. 2015-0022	San Diego Gas & Electric Company (California PUC) ENSTAR Natural Gas Company (Regulatory Commission of Alaska) Atmos Energy Corporation (Mississippi PSC) Mountaineer Gas Company (West Virginia PSC) Virginia Electric and Power Company (Commonwealth of Virginia SCC) Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T 15-07-38	West Virginia-American Water Company (West Virginia PSC) Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
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15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
U-15-016	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
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P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
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Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Cause No. 45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)
Docket No. D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645 E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	
R-2018-3003558, R-2018-3003561	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
Cause No. 45142	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
U-18-043	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
T-03214-17-0305	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
Docket No. D2018.9.60	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. 4890	Montana-Dakota Utilities Co. (Montana PSC)
PUR-2018-00131	Narragansett Bay Commission (Rhode Island PUC)
EL18-152-000	Columbia Gas of Virginia (Virginia SCC)
PUR-2018-00175	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
	Virginia-American Water Company (Virginia SCC)

A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. D2018.2.12	NorthWestern Energy (Montana PSC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
PUC Docket No. 49494	AEP Texas, Inc. (Texas PUC)
Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
U-19-020	Chugach Electric Association, Inc. and Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
A-2018-3006061, A-2018-3006062, and A-2018-3006063	Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, and Peoples Gas Company LLC (Pennsylvania PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)
E-01933A-19-0028	Tuscon Electric Power Company (Arizona CC)
G-01551A-19-0055	Southwest Gas Corporation (Arizona CC)
2018-UN-205	Entergy Mississippi, LLC (Mississippi PSC)
W-03039A-17-0295, W-03039A-19-0092, and WS-01303A-19-0092	Brooke Water, LLC and EPCOR Water Arizona (Arizona CC)
Docket No. 4975	Block Island Utility District d/b/a Block Island Power Company (Rhode Island PUC)
A-2019-3014248	Pennsylvania-American Water Company and Wastewater System Assets of Kane Borough (Pennsylvania PUC)
Docket No. 4994	Providence Water Supply Board (Rhode Island PUC)
19-0791-GA-ALT	Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Ohio PUC)
U-19-070/U-19-071/ U-19-087/U-19-088	Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
Docket No. 42516	Georgia Power Company (Georgia PSC)
20200070-EI	Gulf Power Company (Florida PSC)
20200071-EI	Florida Power & Light Company (Florida PSC)
20200092-EI	Florida Power & Light Company and Gulf Power Company (Florida PSC)
20-GREC-01	Fitchburg Gas and Electric Light Company d/b/a Unitil (Massachusetts DPU)
20-GREC-03	Boston Gas Company and Colonial Gas Company d/b/a National Grid (Massachusetts DPU)
20-GREC-04	Liberty Utilities (New England Natural Gas Company) Corp d/b/a Liberty Utilities (Massachusetts DPU)
PUR-2020-00015	Appalachian Power Company (Virginia SCC)
20-0414-G-390P	Hope Gas, Inc. dba Dominion Energy West Virginia (West Virginia PSC)
Cause No. 45032-S16	Hamilton Southeastern Utilities, Inc. (Indiana URC)
2019.1.101	NorthWestern Energy (Montana PSC)

A-2019-3015173	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority (Pennsylvania PUC)
R-2020-3019369 and R-2020-3019371 2020.06.076 P-20-005 2020.05.055 2020.05.066 PUR-2020-00169 20-0746-G-42T	Pennsylvania American Water Company (Pennsylvania PUC) Montana-Dakota Utilities Co. (Montana PSC) Cook Inlet Pipeline LLC (Regulatory Commission of Alaska) Montana-Dakota Utilities Co. (Montana PSC) NorthWestern Energy (Montana PSC) Virginia Electric and Power Company (Virginia SCC) Hope Gas, Inc., d/b/a Dominion Energy West Virginia (West Virginia PSC)
20-553-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Rider of the Dayton Power and Light Company (Ohio PUC)
E-01345A-19-0236 U-20-012	Arizona Public Service Company (Arizona CC) Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
Docket No. 20-01-31	The Southern New England Telephone Company d/b/a Frontier Communications of Connecticut (SNET) (Connecticut PURA)
P-2020-3021191 A-2021-3026523, A-2021-3026515, and A-2021-3026522	Peoples Natural Gas Company LLC (Pennsylvania PUC) Joint Application of Veolia Environnement S.A., Veolia North America, Inc., SUEZ S.A., SUEZ Water Pennsylvania Inc. and SUEZ Water Bethel Inc. (Pennsylvania PUC)
A-2021-3026794 and A-2021-3026796	Joint Application of Peoples Natural Gas Company LLC and Peoples Gas Company (Pennsylvania PUC)
A-2021-3026774 and A-2021-3026775	Joint Application of Aqua Pennsylvania Inc., and Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
A-2021-3024267 R-2021-3027385 and R-2021-3027386	Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC) Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
21-0595-WW-AIR 21-0596-ST-AIR 21-0369-W-42T U-21-058	Aqua Ohio, Inc. (Ohio PUC) Aqua Ohio Wastewater, Inc. (Ohio PUC) West Virginia-American Water Company (West Virginia PSC) Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
E-01345A-21-0056	Fuel and Purchased Power Audit of Arizona Public Service Company (Arizona CC)
SW-20445A-20-0214 et al PUR-2021-00058 U-21-070/U-21-071	Global Water Resources, Inc. (Arizona CC) Virginia Electric and Power Company (Virginia SCC) Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
U-22-001	Railbelt Reliability Council for Certification of an Electric Reliability Organization (Regulatory Commission of Alaska)
Docket No. 44160 22-620-GA-RDR	Georgia Power Company Integrated Resource Plan (Georgia PSC) Plant in Service and Capital Spending Prudence Audit of Vectren Energy Delivery of Ohio, Inc. d/b/a CenterPoint Energy Ohio (Ohio PUC)
PUR-2021-00255 RP19-3-003 22-0304-E-P	Virginia-American Water Company (Virginia SCC) El Paso Natural Gas Company, LLC (FERC) Appalachian Power Company and Wheeling Power Company (West Virginia PSC)

R-2022-3031672 and R-2022-3031673 22-0294-G-PC	Pennsylvania-American Water Company (Pennsylvania PUC) Hope Gas, Inc., dba Dominion Energy West Virginia and Hope Gas Holdings (West Virginia PSC) Southwest Gas Corporation (Arizona CC) NorthWestern Energy (Montana PSC)
G-01551A-21-0368 2022-06-064 U-21-088, U-21-089, U-22-006, U-2-007, U-22-008, U-22-009	Sand Point Generating, LLC, North Slope Generating, LLC, TDX Manley Generating, LLC, TDX North Slope Generating, LLC, Sand Point Generating, LLC, TDX ADAK Generating, LLC. (Regulatory Commission of Alaska)
20220067-GU	Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division (Florida PSC)
PUR-2020-00015 U-22-029	Appalachian Power Company – Remand (Virginia SCC) Golden Valley Electric Association, Inc. (Regulatory Commission of Alaska)
22-0393-E-ENEC	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
E-01773A-21-0298 Docket No. 44280 FTC-01/2021-BL&P- RRA-20211004	Arizona Electric Power Cooperative, Inc. (Arizona CC) Georgia Power Company (Georgia PSC)
U-22-002 and U-22-003	Barbados Light & Power Company Limited (Barbados Fair Trading Commission)
A-2019-3015173	Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
2022.07.078 A.22-05-016 2022-UN-86/2022-UN-087 E-01933A-22-0107 A-2022-3035298, A-2022-3035299, A-2022-3035490, A-2022-3035492	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority - Remand (Pennsylvania PUC) NorthWestern Energy (Montana PSC) San Diego Gas & Electric Company (California PUC) Great River Utility Operating Company, LLC (Mississippi PSC) Tucson Electric Power Company (Arizona CC)
PUR-2022-00052 U-22-078	Manwalamink Water Company, Manwalamink Sewer Company, NextEra Water Pennsylvania, LLC (Pennsylvania PUC) Virginia Natural Gas, Inc. (Virginia SCC) Alaska Electric Light & Power Company (Regulatory Commission of Alaska)
U-22-081 22-47-WW E-01345A-22-0144 E-04204A-22-0251 PUR-2023-00002 22-1094-WW-AIR 22-1096-ST-AIR A-2022-3037047, et al.	ENSTAR Natural Gas Company (Regulatory Commission of Alaska) Narragansett Bay Commission (Rhode Island PUC) Arizona Public Service Company (Arizona CC) UNS Electric, Inc. (Arizona CC) Appalachian Power Company (Virginia SCC) Aqua Ohio, Inc. (Ohio PUC) Aqua Ohio Wastewater, Inc. (Ohio PUC) Pennsylvania-American Water Company, Butler Area Sewer Authority (Pennsylvania PUC)
PUR-2023-00067 and PUR-2023-00112	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
Docket No. 54634	Southwestern Public Service Company (Texas PUC)

23-0089-EL-RDR	Duke Energy Ohio, Inc. (Ohio PUC)
23-0280-G-42T	Mountaineer Gas Company (West Virginia PSC)
2022-0208	Kauai Island Utility Cooperative (Hawaii PUC)
PUR-2023-00101	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
23-0383-W-42T and	
23-0384-S-42T	West Virginia-American Water Company (West Virginia PSC)
23-0460-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
R-2023-3043189&	
R-2023-3043190	Pennsylvania-American Water Company (Pennsylvania PUC)
U-23-047/U-23-048	Chugach Electric Association (Regulatory Commission of Alaska)
U-23-054	Alaska Power Company (Regulatory Commission of Alaska)
U-23-065 through U-23-073	Alaska Waste (Regulatory Commission of Alaska)
T-03214A-23-0250	Citizens Telecommunications of the White Mountains, Inc., dba Frontier Communications of the White Mountains (Arizona CC)
PUR-2023-00194	Virginia-American Water Company (Virginia SCC)
G-01551A-23-0341	Southwest Gas Corporation (Arizona CC)
PUR-2024-00024	Appalachian Power Company (Virginia SCC)
R-2024-3047822 &	
R-2024-3047824	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
U-24-005/U-24-006	Municipality of Anchorage d/b/a Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
24-14-EL	Pascoag Utility District (Rhode Island PUC)
2022-0140	Hawaii Water Service Company, Inc. (Hawaii PUC)
24-0185-EL-RDR	AEP Ohio Company, d/b/a AEP-Ohio (Ohio PUC)
20240068-WS	Sunshine Water Services Company (Florida PSC)
W-02074A-23-0337,	
W-02465A-23-0338,	
WS-02060A-23-0339,	
WS-02676A-23-0340,	
WS-02676A-24-0029,	
W-02074A-24-0030,	
W-02465A-24-0031, and	
WS-02060A-24-0033	Liberty Utilities (Arizona CC)
2024.08.088	NorthWestern Energy, Energy West Montana, Inc., and Cut Bank Gas Company (Montana PSC)
2024.05.053	NorthWestern Energy (Montana PSC)
2024-0158	The Gas Company, LLC dba Hawaii Gas (Hawaii PUC)
24-41-WW	Narragansett Bay Commission (Rhode Island PUC)
E-01773A-24-0220	Arizona Electric Power Cooperative, Inc. (Arizona CC)
U-24-030/U-24-031	Golden Heart Utilities, Inc. and College Utilities Corporation (Regulatory Commission of Alaska)
24-51-WW	Providence Water Supply Board (Rhode Island PUC)
2024-0224	Waikoloa Resort Utilities, Inc., dba West Hawaii Utility Company, Waikoloa Sanitary Sewer Company, Inc., dba West Hawaii Sewer Company, Waikoloa Water Co., Inc., dba West Hawaii Water Company (Hawaii PUC)
56002 & 56003	Georgia Power Company Integrated Resource Plan (Georgia PSC)
24-0854-E-42T	Appalachian Power Company and Wheeling Power Company (WV PSC)
G-04204A-24-0237	UNS Gas, Inc. (Arizona CC)
PUR-2025-00058	Virginia Electric and Power Company (Virginia SCC)
P-24-013	Kenai Beluga Pipeline, LLC (Regulatory Commission of Alaska)

PC Ex. 62.02

Qualifications of Mark S. Dady

PC Ex. 62.02
QUALIFICATIONS OF MARK S. DADY

As a certified public accountant and regulatory analyst with Larkin & Associates, Mr. Dady's responsibilities include preparing written testimony and testifying as a witness at regulatory hearings as well as assisting with the review and analysis of regulatory filings, the preparation of computer spreadsheets and models, the preparation of discovery requests, performing accounting and regulatory research, drafting and editing written reports and the verification of data.

Relevant Regulatory Experience

Following are examples of recent regulatory cases in which Mr. Dady has participated.

- Project Team Member in the Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio. Larkin & Associates' report addressed the following issues: Status of the Company's Implementation of Recommendations from 2012, 2013, 2014/2015, and 2016 Audits; Management/Performance Audit of Rider AER-R; Financial Audit of Rider AER-R; and GoGreen Power Pricing Program.
- Project team member in the review of Mountaineer Gas Company's requested increase in rates. Issues addressed in testimony included: Reflect Year-End Plant-in-Service Balances for IREP Included Plant Accounts; Accumulated Depreciation for IREP Included Plant Accounts; Accumulated Deferred Income Taxes for IREP Included Plant Accounts; Depreciation Expense for IREP Included Plant Accounts; Property Tax Expense for IREP Included Plant Accounts; Remove Company Adjustment to Revenue and Purchased Gas for 10-Year Forecasted Weather Trend; Adjustment to Transportation Revenue for Forecasted Weather Trend; Weather Normalization; Amortization of Regulatory Liability for Unprotected EADIT; Amortization of Regulatory Liability for Protected EADIT; Remove Company Proposed Adjustment to Normalize State Income Taxes; Uncollectibles Expense on Adjustments to Revenues; Uncollectibles Expense Adjustment for Write-Off Percentage; Interest Synchronization; Base Rate Revenue Requirement Related to Inclusion of December 31, 2018 Plant in Service for IREP-Includable Plant Accounts and Need to Coordinate Base Rate and IREP Revenue Requirements; Reduced Use and Potential Misapplication of Seaboard Allocator in Cost of Service Study.
- Project team member in the review of Georgia Power Company's Integrated Resource Plan. Issues addressed in testimony included: Requests for Approval of Costs and Cost Recovery should be Addressed in Other Forums Where the Company's Earnings and Risk are Considered, Rather Than in the 2019 IRP Proceeding; Georgia Power's Requested Accounting Reclassifications and Amortizations should be Reviewed in a Forum Which Considers Georgia Power's Costs and Earnings; Georgia Power's Plant Held for Future Use for Projects Addressed in prior Integrated Resource Plans but which are not in Georgia Power's 2019 Integrated Resource Plan, or which have Projected "Use" Dates of 2030 or Beyond, should be Considered in the Company's 2019 Rate Case; Land Purchased by the Company in Stewart County, Georgia for a Future Generating Plant Site that was Evaluated by the Company for a New Nuclear Unit; Other Costs Incurred by the Company for a New Nuclear Unit at the Stewart County, Georgia Future Generating Plant Site; Coal Combustion Residuals – Company's Total Anticipated Expenditures; Georgia Power Research Activities; Costs that the Company has Estimated for 50MW of Battery Energy Storage Systems; Approval of the Company's Environmental Compliance Plan and Reserve Decision about the Cost to Other Proceedings Where the Company's Earnings and Cost of Service are being Addressed.

- Project team member in the review of Montana-Dakota Utilities Co.’s requested increase in rates. Issues addressed in testimony included: Preferred Stock Redemption; Pension Asset; Cash Working Capital; Depreciation Expense; Preferred Stock Redemption Amortization; Labor Expense; Benefits Expense; Subcontract Labor; Cost of Fuel, Purchased Power, and RTO Transmission Service Expense; Insurance Expense; Directors and Officers Liability Insurance; Software Maintenance Expense; Rent Expense; Big Stone and Coyote Generating Stations; Production Easements; Uncollectibles Expense; Interest Synchronization; Rate Case Expense; Stock-Based Compensation; Non-Employee Board of Directors Stock Awards; Payroll Tax Expense; Excess Accumulated Deferred Income Taxes; Company-Proposed Transfer of RTO Transmission Costs into the Fuel and Purchased Power Cost of Tracking Adjustment Mechanism.
- Project team member in the review of Aqua Pennsylvania Inc.’s requested increases in rates. Issues addressed in testimony included: Average FPFTY Rate Base; Cash Working Capital; Acquisition Adjustments; Acquisition Adjustment – TESI – Beech Mountain Lakes Resort Community Water System; Acquisition Adjustment – BCWSA/Concord Park Community; Acquisition Adjustment – Sand Springs Water Company, Inc.; Acquisition Adjustment – TESI – Treasure Lake Community Sewer System; Acquisition Adjustment – Township of Tobyhanna; ADIT for Remaining “Catch Up” Repairs Deduction; Depreciation Expense; Rate Case Expense; Acquisition Adjustment Amortization – TESI - Beech Mountain; Acquisition Adjustment Amortization – Concord Park; Acquisition Adjustment Amortization – Sand Springs; Acquisition Adjustment Amortization – TESI – Treasure Lake; Acquisition Adjustment Amortization – Tobyhanna; Negative Acquisitions Adjustment Amortization; Payroll Expense – Vacancy Rate; Stock-Based Compensation Expense; Payroll Tax Expense; Employee Group Insurance; Income Tax Expense – Normal Level of Repairs Deduction; Interest Synchronization; Deferred Income Taxes for Repairs Deductions; Act 40 Requirements; The Revenue Use Differential; The “Revenue Use” Differential Applicable to Infrastructure; The “Revenue Use” Differential Applicable to “General Corporate Purposes”; Post-FPFTY Accumulations of Act 40 “Revenue Use” Differential Amounts; Reflection of ADIT in Utility Infrastructure Surcharge Mechanisms (Such as DSICS); The New 21 Percent Corporate Income Tax Rate; TCJA Saving During 2018 and 2019; Excess Accumulated Deferred Income Taxes; Tax Year 2017 Bonus Tax Depreciation; and Ratemaking Issues with Aqua PA’s Tax Deductions for Repairs.
- Project team member in the review of Vectren Energy Delivery of Ohio Inc.’s requested approval of an alternative rate plan and an increase in rates. Issues addressed in testimony included: Unprotected Excess Deferred Income Tax Amortization; Investor Relations Expense; and DARR and IM Program Expenses.
- Project team member in the review of Montana-Dakota Utilities Co.’s concerning Federal Tax Reform Impacts on the Company’s Electric Operations Revenue Requirements. Estimated Revenue Requirement Reduction; Excess Accumulated Deferred Income Taxes; and Company-Proposed Calculation and Application of TCJA Savings.
- Project team member in the review of Montana-Dakota Utilities Co.’s requested increase in rates. Issues addressed in testimony included: Provision for Pension & Benefits; Discontinued Service – Saco/Bowdoin; Accumulated Depreciation – Adjustment for Recommended Depreciation Rates; Depreciation Expense – Adjustment for Recommended Depreciation Rates; Pension Expense; Discontinued Service – Saco/Bowdoin; Gain/(Loss) on Disposal of Property; Stock-Based Compensation; Interest Synchronization; Adjust Current Income Tax Expense for New 21%

Federal Income Tax Rate; Adjust Deferred Income Tax Expense for New 21% Federal Income Tax Rate; and Excess Accumulated Deferred Income Taxes.

- Project team member in the review of Mississippi Power Company's concerning encouraging stipulation of matters in connection with the Kemper County IGCC Project. Issues addressed in testimony included: Overview of Negotiations; Offers made by Staff General Discussion; Offers made by Company General Discussion; Concessions made by Staff (and Commission); Offer made by Staff – Detailed Discussion of Revenue Requirement; Offers made by Company and Why They are not Acceptable; AFUDC; Beneficial Capital, Force Majeure and Change in Law; Regulatory Assets Not Recorded on MPC's Books; CCPI Credits; Recapitalization of Previously Written Off Expenses; Return and No Performance Adjustment; Capital Cost True-up; Over-Collection of Amortization Expense; Land Costs; 2018 Settlement Revenue Requirement (Before Considering the Impact of Federal Income Tax Reform); Incorporating the Impact of Federal Income Tax Reform on the 2018 Kemper Revenue Requirement; Differences Between Staff and Mississippi Power Company; Differences Between Staff and Chevron, FEA and Chemours Company Witness Gorman; Testimony of Charles Griffey on Behalf of Greenleaf CO2 Solutions.
- Project team member in the review of Kentucky Power Company's requested increases in rates. Issues addressed in testimony included: Cash Working Capital; Theft Recovery Revenue; Payroll Expense – Employee Merit Increases; Overtime Payroll Expense – Employee Merit Increases; Payroll Tax Expense; Incentive Compensation Expense; Stock-Based Compensation Expense; Savings Plan Expense; Supplemental Executive Retirement Program; Corporate Aviation Expense; Storm Damage Expense; Test Year Relocation Expense; Gain on Sale of Utility Property; Cash Surrender Value of Life Insurance Policies; Interest Synchronization; Rate Case Expense; Risk for Mitchell Plant Ash Pond Costs; Environmental Surcharge for the Rockport Unit 1 SCR; Rockport Plant Unit Power Sales Agreement – Return on Equity of 12.16 Percent; and Purchase Power Adjustment Rider.
- Project team member in the review of Pennsylvania American Water Company's requested increases in rates. Issues addressed in testimony included: Use of Average Fully Projected Future Test Year; Average 2018 Rate Base; Acquisition Adjustments (Scott Township System, Koppel Borough Wastewater System, Hamiltonban Township Municipal Authority, New Cumberland Borough, and Scranton Wastewater Utility); Cash Working Capital; Declining Residential Usage; Customer Revenue Annualization; Changes in Power and Chemical Costs; Interest Synchronization; Salary and Wages and Payroll Taxes; Annual Performance Plan; Stock-Based Compensation Expense; Group Insurance Expense; 401(k), Defined Contribution Plan and Employee Stock Purchase Plan; Rate Case Expense; Negative Acquisition Adjustment Amortization; Office Rental Income; Annual Performance Plan – American Water Works Service Company; Stock-Based Compensation – American Water Works Service Company; Miscellaneous Expenses – American Water Works Service; Property Tax Expense; Acquisition Amortization – Scott Township; Depreciation Expense; Acquisition Amortization – Koppel Borough; Acquisition Amortization – Hamiltonban Township Municipal Authority; Acquisition Amortization – New Cumberland Borough; Acquisition Amortization – Scranton Sewer Authority; Act 40 Application of Revenue Use Differential Amounts; Reflection of ADIT in Utility Infrastructure Surcharge Mechanisms (such as DSICS); Comparison of Actual Versus PAWC Claimed Operating Expenses and Rate Base for the 12 Months Ending December 31, 2014; and PAWC's Request for a Return on Equity Enhancement Based on Management Performance.

- Project team member in the review of Puget Sound Energy, Inc.'s requested increases in rates. Issues addressed in testimony included: White River Hydroelectric Project; Production Adjustment; Accumulated Depreciation; Accumulated Deferred Income Taxes; Plant Held for Future Use; Temperature Normalization; Bad Debt Expense; Incentive Compensation Expense; Interest on Customer Deposits; Payroll Expense; Investment Plan Expense; Power Costs; Montana Electric Energy Tax; Storm Damage Expense; White River Amortization Expense; Production Expense Adjustment; Depreciation & Amortization Expense Under Proposed New Depreciation Rates; Interest Synchronization; Pension Expense; Environmental Remediation Expense; Credit Card Payment Processing Costs; Costs Requested by PSE Related to Colstrip; Colstrip Plant and Accumulated Depreciation; Costs for Decommissioning and Demolition; PSE's Proposed Use of Production Tax Credits to Recover Colstrip Units 1 and 2 Costs; Costs for Colstrip Coal Combustion Residuals; and Operating and Maintenance Expense.
- Project team member in the evaluation of the capacity rate issues of DTE Electric Company. Issues addressed in testimony included: Capacity Costs; the 75-0-25 Production Cost Allocator; Energy Market Sales Revenue, Off-System Energy Sales Revenue, and Ancillary Service Revenue, Net of Related Fuel Costs; Net Capacity Cost; DTE's Owned and Purchased Capacity in MW; and Calculation of the State Reliability Mechanism Capacity Rate.
- Project team member in the evaluation of the capacity rate issues of Consumers Energy Company. Issues addressed in testimony included: Capacity Costs; the 75-0-25 Production Cost Allocator; Energy Market Sales Revenue, Off-System Energy Sales Revenue, and Ancillary Service Revenue, Net of Related Fuel Costs; Net Capacity Cost; Consumers' Owned and Purchased Capacity in MW; Calculation of the State Reliability Mechanism Capacity Rate; and Comparative Calculation of a Capacity Rate on a \$/MW-Year Basis Presented by Consumers in Case No. U-18392.
- Project team member in the review of Arizona Public Service Company's requested increases in rates. Issues addressed in testimony included: Post-Test Year Plant Additions – Fossil; Post-Test Year Plant Additions – Nuclear Generation; Post-Test Year Plant Additions – Distribution, Information Technology and Facilities; Post-Test Year Plant Additions – Customer Services; Post-Test Year Plant Additions – Renewables, Microgrid and Technology Innovation; Accumulated Depreciation through September 30, 2016; Accumulated Deferred Income Taxes through September 30, 2016; Working Capital; Cash Working Capital; Property Tax Deferral; Other Rate Base Updates; Supplemental Executive Retirement Benefits; Stock-Based Compensation; Post-Test Year Plant Depreciation and Property Tax Expense – Fossil Generation; Post-Test Year Plant Depreciation and Property Tax Expense – Nuclear Generation; Post-Test Year Plant Depreciation and Property Tax Expense – Distribution, Information Technology and Facilities; Post-Test Year Plant Depreciation and Property Tax Expense – Customer Service; Post-Test Year Plant Depreciation and Property Tax Expense – Renewables, Microgrids and Technology Innovation; Revenue from Arizona State University and PayPal for Red Rock Solar Generating Facility; Property Tax Expense; Interest Synchronization; Base Cost of Fuel and Purchased Power; Depreciation Expense; Storm Restoration Expense; Distribution Vegetation Management Expense; Directors' and Officers' Liability Insurance Expense; Annual Incentive Compensation; Depreciation Terminology and Concepts; APS's Proposed New Depreciation Rates; APS's Current and Proposed Depreciation Rates for Meters; Cost of Removal Component of APS's Proposed Depreciation Rates; Staff Recommended Alternative for Deriving APS's Cost of Removal – The Present Value Approach (Similar to what has been adopted in Maryland and the District of Columbia); Typical Arguments Presented by Utilities Against Using a Present Value Method for the Cost of Removal Component of Depreciation Rates; Staff

Recommendation on Depreciation Rates; Red Rock Solar Generating Facility and Related Regulatory Liability Account; Ocotillo Deferral Request; Four Corners Selective Catalytic Reduction Deferral and Step Increase Request; Property Tax Deferral Request; Environmental Chemical Costs; Costs of Water to Supply APS's Generation Plants; Costs of Third-Party Electric Storage (e.g., Battery) Contracts; and Company Requested Compliance Items to be Eliminated.

- Project team member in the review of Louisville Gas and Electric Company's requested increases in rates. Issues addressed in testimony included: "Slippage Factor" Adjustment to Plant and CWIP; Distribution Automation; Cash Working Capital; Advanced Metering Systems; Gas Line Tracker Amounts in Base Rates; Interest Synchronization; Incentive Compensation Expense; Advanced Metering Services Operating Expenses; Transmission Vegetation Management Expense; Uncollectibles Expenses; Depreciation Expense Related to Plant Slippage; Depreciation Expense Related to Distribution Automation; Payroll and Employee Benefits for Vacant Positions; Administrative Charges from PPL Services – Affiliated Service Company; Gas Line Tracker Amounts in Base Rates; Rescheduling of Expiring Regulatory Asset Amortizations; Amortization Period for Remaining Net Book Value of Retired Meters that are Being Replaced with New Electric Utility AMS Meters; and Off-System Sales Margin Sharing.
- Project team member in the review of Kentucky Utilities Company's requested increases in rates. Issues addressed in testimony included: "Slippage Factor" Adjustment to Plant and CWIP; Distribution Automation; Cash Working Capital; Advanced Metering Systems; Interest Synchronization; Incentive Compensation Expense; Advanced Metering Services Operating Expenses; Transmission Vegetation Management Expense; Uncollectibles Expenses; Depreciation Expense Related to Plant Slippage; Depreciation Expense Related to Distribution Automation; Payroll and Employee Benefits for Vacant Positions; Administrative Charges from PPL Services – Affiliated Service Company; Amortization Period for Remaining Net Book Value of Retired Meters that are Being Replaced with New Electric Utility AMS Meters; and Off-System Sales Margin Sharing.
- Project team member in the review of ENSTAR Natural Gas Company's requested increases in rates. Issues addressed in testimony included: Adjustment to Revenue and Gas Cost for Customer Usage and Sales; Rate Base Adjustments for Prepayments and Debt Expense; SEMCO Charges to ENSTAR; Cash Working Capital; Adjust Deferred Income Tax Deduction in Rate Base; Income Tax Allowance; Cost of Service Study Use in Utility Ratemaking; ENSTAR's Cost of Service Study; Adjustments to ENSTAR Cost of Service Study Allocation Factors; RAPA Adjusted Cost of Service Study; and Rate Design.
- Project team member in the review of Pennsylvania FirstEnergy's requested increases in rates for West Penn Power Company, Pennsylvania Electric Company, Pennsylvania Power Company, and Metropolitan Edison Company. Issues addressed in testimony included: Average Rate Base for the Fully Projected Test Year; Deferred Extraordinary Storm Costs and Storm Reserves; Accumulated Depreciation – Impact of New Depreciation Rates; Cash Working Capital; Depreciation Expense at Proposed Rates Using Average Plant Balances; Miscellaneous Expenses; Incentive Compensation Expense; Stock-Based Compensation Expense; Supplemental Executive Retirement Plan Expense; Payroll Expense; Payroll Tax Expense; Employee Benefits; Pension Expense; Post Retirement Benefits Other Than Pensions; Affiliate Aircraft Expense; Rate Case Expense; Interest Synchronization; Act 40 Application of Revenue Use Differential Amounts; Reflection of ADIT in Utility Infrastructure Surcharge Mechanisms.

- Project member in the review of Virginia-American Water Company's rate request. Issues addressed in testimony included: The Infrastructure Replacement Program; Infrastructure Replacement Plan Eligible Plant; Customer Protections and Reporting; Reconciling and True-up Process; Rate Base offset for Accumulated Deferred Income Taxes; ADIT Related to Accelerated and Bonus Tax Depreciation and Net Operating Losses; Reduction to Company's Risk; Use of Projections as the Basis for an IRP Surcharge; Weston and Webster Springs Interconnection Project; and Annual Depreciation Expense Offset.
- Project member in the review of certain issues concerning the Revenue Requirement Revisions designated as Tariff Revisions for water and wastewater public utility service of Golden Heart Utilities, Inc., and College Utilities Corporation. Issues addressed in testimony included: Prepaid Expenses; Accrued Taxes Payable; Accrued Vacation; Cash Working Capital; Customer Deposits; Unamortized Debt Discount; Accumulated Deferred Income Taxes; Payroll; Payroll Tax Expense; CUC 401(k) Plan Expense; USA Payroll Expense Adjustment with USA Overheads Allocated to Utilities; Corporate Governance Expense; Meals and Entertainment; Directors and Officers Liability Insurance; Tax Preparation Fees; Meals and Entertainment Expense; Depreciation Expense; Utility Services of Alaska Rate Base/Rate of Return Adjustments; University of Alaska Fairbanks Special Contract Revenues and Expenses; Current Federal and State Income Tax Expense; §199 Special Deduction for Domestic Production Activities; and Plant Replacement and Improvement Surcharge Mechanism.
- Project member in the review of the rate request of Missouri American Water Company. Issues addressed in testimony included: Business Transformation; Deduction for Domestic Production Activities under §199 of the Internal Revenue Code and an Illustrative "Separate Return" Basis Calculation of the DPAD; American Water Works' Decision to not take Bonus Tax Depreciation because of Parent Company Consolidated Net Operating Loss Carryforwards and Charitable Deduction Carryforwards; Rate Design; Single Tariff or District Specific Pricing; Cost of Service Study – St. Louis Metro District; MAWC Proposed State-Wide Customer Charges; Allocation of Power Costs for the St. Louis Metro District, and Distinct Cost Differences/MAWC Proposal for State-Wide Rate Consolidation.
- Project member in the review of MPCo's request for a change of rates. Issues addressed in testimony included: Cost of Gas-Fired Combined Cycle Generation Included in Certification Estimate; Cost Cap Exceptions for Beneficial Capital, Force Majeure and Change in Law; MPCo Assumption for Securitization Occurring in April 2016; Regulatory Asset Amortization Period; Incentive and Stock-Based Compensation; Treatment of Ad Valorem Taxes on the In-Service Assets; and Return on Equity Used and Concerns About MPCo's Proposed Capital Structure.
- Project team member in the review of the rate request of West Virginia American Water Company. Issues addressed in testimony included: cash working capital; residential declining usage; power and chemical expense; consolidated income tax savings; insurance other than group expense; rate case expense; payroll expense; payroll tax expense; 401(k) plan expense; defined contribution plan expense; post-retirement benefits other than pension expense ("PBOP"); depreciation expense based on proposed depreciation rates; utility regulatory assessment expense – intrastate revenue; income tax expense – interest synchronization; service company support costs – general discussion; affiliate management fees – miscellaneous expenses; affiliate management fees – incentive compensation – annual incentive plan; affiliate management fees – stock based compensation expense; and officer expenses.

- Project team member in the review of Virginia Electric and Power Company's biennial review. Issues addressed in testimony included: 2013 and 2014 Biennial Review Period Earnings; Ratemaking Analysis of Prospective Revenue Sufficiency; Loss Contingency Related to Coal Ash Ponds; Removal of Major Storm Expense for Prospective Ratemaking; Long Term Incentive Plan Performance Award Costs Recorded During 2014 that Exceeded a Payout Percentage of 100 Percent; Special One-Time Restricted Stock Awards Expense; Conforming Changes to Interest Synchronization; Property Tax Expense Functionalization; Projected Environmental Compliance Costs for Prospective Ratemaking; Fossil Plan O&M Costs for Prospective Ratemaking; and Income Tax Expense.
- Project team member in the review of ENSTAR's request for an increase in rates. The testimony focused on the following issues: Adjustment to Revenue and Gas Cost for Customer Usage and Sales; Cost of Service Study; Rate Design; and 2014 Bonus Tax Depreciation.
- Project team member in the review of Mountaineer Gas Company's requested increases in rates. Issues addressed in testimony included: 2014 Bonus Depreciation; Prepayments; New Corporate Headquarters Building; Weather Normalization of Test Year Revenue and Gas Costs; Payroll Expense; 401K Expense; Payroll Tax Expense; Employee Benefits Expense; Depreciation Expense Based on Proposed Depreciation Rates; Charitable Contributions; Injuries and Damages Expense; Lease and Depreciation Expense Related to New Corporate Headquarters; Miscellaneous Expense; Outside Services Expense; Regulatory Commission Expense; Interest Synchronization; IGS Management Services; Advertising Expense; and Current State and Federal Income Tax Expense.
- Project team member in the review of Kentucky Power Company's requested increase in rates. Issues addressed in testimony included: Accumulated Deferred Income Taxes – 2014 bonus tax depreciation; contributions in aid of construction; cash working capital; commercial and industrial revenue; amortization of deferred IGCC costs; amortization of deferred CCS FEED Study costs; amortization of deferred CARRS site costs; amortization of deferred preliminary Big Sandy FGD costs; parent company loss allocation; incentive compensation expense; stock-based compensation expense; Engage to Gain program costs; PJM charges and credits to reflect removal of Big Sandy; miscellaneous expenses; Mitchell plant maintenance expense; interest synchronization; Big Sandy Retirement Rider; Big Sandy Unit 1 Operation Rider (BS1OR); Environmental surcharge related to Mitchell FGD; Kentucky Economic Development Surcharge; Transmission adjustment; Mitchell plant transfer/Ash Pond costs; Off system sales margin sharing; vegetation management; and Rockport plant unit power sales agreement – return on equity of 12.16 percent.
- Project team member in the review of Pennsylvania FirstEnergy's requested increases in rates for West Penn Power Company, Pennsylvania Electric Company, Pennsylvania Power Company, and Metropolitan Edison Company. Issues addressed in testimony included: Average Rate Base for the Fully Projected Test Year; Deferred Storm Damage; Depreciation Reserve Related to Legacy Meters; Cash Working Capital; Corrections to Remove Transmission Projects from Account 303, Miscellaneous Intangible Plant; Mobile Work Management System Corrections, Account 303, Miscellaneous Intangible Plant; ADIT – Impact of 2013 Change in Tax Accounting Method; ADIT – Error Correction; Consolidated Tax Savings; Miscellaneous Expenses; Amortization of Deferred Storm Damage Expense; Amortization of Merger Storm Damage Deferral; Amortization Expense Related to Legacy Meters; Payroll Expense; Payroll Tax Expense; Employee Benefits; Depreciation Expense – Removal of Transmission Project from Account 303; Depreciation Expense – Mobile Work Management System; Vegetation

Management; Rate Case Expense; Interest Synchronization; Pension Expense; Post Retirement Benefits Other Than Pensions; Storm Damage Reserve and Rider; and Federal 2014 Tax Extenders.

- Project team member in the review of Monongahela Power Company and The Potomac Edison Power Company's requested increase in rates. Issues addressed in testimony included: Three deactivated subcritical generating plants (Albright, Rivesville, and Willow Island); cash working capital; property tax payment lag; terminal treatment: post test year environmental pollution control projects; terminal treatment: 2014 MATS control projects; vegetation management year one capital distribution plant; business and occupation taxes; vegetation management expense; revenue at current base rates that should not be removed; payroll expense; savings plan expense; payroll tax expense; incentive compensation and corporate incentives; meter reading expense; depreciation expense – new depreciation rates; payroll expense – new hires related to Harrison Asset Transfer settlement; lease expense; amortization expense related to three deactivated plants; consolidated income tax savings; interest synchronization; depreciation expense – Harrison power station; depreciation expense related to environmental control projects; depreciation expense related to MATS pollution control projects; depreciation expense on vegetation management year one capital distribution plant; vegetation management surcharge; and the Harrison plant acquisition adjustment.
- Project team member in the prudence review of construction costs recorded by MPC related to the Kemper County Integrated Gas Combined Cycle (IGCC) plant on behalf of the Mississippi Public Service Staff for costs incurred through March 31, 2013. Larkin's portion of the prudence review consists of examining invoices and other documentation provided by the Company related to construction costs incurred in conjunction with the construction of the Kemper County IGCC plant.
- Project team member in the review of Georgia Power Company's Annual Surveillance Report. Larkin conducted an extensive review of the Company's 2013 ASR filing in order to: replicate and verify the Company's return on equity calculation to ensure it placed within the Commission's ordered ROE band, ensure that the Company's regulatory adjustments were made in compliance with Commission orders, and identify issues and/or adjustments to the Company's filing as appropriate. Larkin's review implemented the following procedures, amongst others, to make its determination with respect to the Company's reported Return on Equity: compared rate base and operating income components year over year, identified changes in adopted accounting methodologies, and identified new transactions, identified variances as a foundation for discovery questions, prepared multiple rounds of discovery questions, and reviewed responses.
- Project team member in the review of Georgia Power Company's request for a rate increase. Issues in testimony included: ECCR Tariff revenue deficiency; DSM Tariff revenue deficiency, Alternative rate plan (2014-2016) revenue deficiency; Municipal Franchise Fee Tariff; steam and other production O&M expense; transmission and distribution O&M expense; wholesale capacity sales revenue; proceeds from sales of scrap material; cash working capital; miscellaneous items/executive financial planning; property tax; interest synchronization; depreciation expense and reserve; Plant Hammond Mercury and Air Toxins Standards (MATS) Project; Plant Branch depreciation; Plant McDonough Unit 6 depreciation; prepaids and deferred debits; operating reserves and deferred credits; Plant Branch Units 1, 3, and 4 net book value; ADIT for deferred nuclear outage cost; ADIT for Purchase Power Agreement (PPA) levelization; pole attachment revenues; revenue for rental of electric property; SERP expense; pension expense; PSC Staff IRP consultant expense; solar implementation and operating expense; income tax expense – state

clean energy credit; hydro tax credit; update SCS allocation factors to use 2012 statistics; GPC charges to Southern Power; stock options and stock based compensation; Southern Company Services (SCS) charges to GPC; Southern Nuclear Company charges to GPC; affiliate PPAs/capital leases with Southern Power Company; GPC charges to other affiliates; GPC charges to Southern Power; GPC charges to Southern Company Services for Atlanta Headquarters Building; GPC charges to SouthernLINC; Section 199 Manufacturing Deduction; FIN 48 uncertain tax positions; performance pay plan; step increase approach; costs resulting from the Plant Bowen incident; and earnings test and earnings sharing.

- Project team member in Potomac Electric Power Company's review of its rate request. Issues in testimony included: Increase in base distribution rates; test year ending December 31, 2012, consisting of 12 months of actual results; adjustments to the test year data for known and measurable changes; rate base; cash working capital allowance; lead-lag study; operating expenses; depreciation rates; are Pepco's depreciation rates computed with the appropriate District of Columbia book reserve; is Pepco's accumulated depreciation reserve computed accurately based on D.C.'s jurisdictional amounts; is Pepco correctly recording its gross salvage value in accordance with FERC's uniform system of accounts; net salvage/net removal cost; comparison of Pepco's requested cost of removal for D.C. distribution plant with the amount allowed in Order No. 15710; comparison of Pepco's requested cost of removal with other alternatives; actual cost of removal; evaluation of Pepco's proposed negative net salvage percentages; rebuttal to Pepco's witness Spanos's June 17, 2013 supplemental testimony accumulated depreciation of historical plant; general and/or specific projects completed in the test year; reliability projects completed in the test year; post-test year additions; ADIT; bonus tax depreciation; impacts of District of Columbia and federal tax regulation; payroll; and employee health and welfare.
- Project team member in the review of Appalachian Power Company rate request. Issues discussed in testimony by Larkin & Associates included: self-funded reserve accruals, prepayments, rate base update, prepaid pension asset, inactive or zero usage materials & supplies inventory, accumulated deferred income taxes, deferred fuel balance, off-system sales margin, customer revenues for growth, interest on customer deposits, donations, written off obsolete inventory, rate case expense, environmental consumable and allowances, depreciation expense, public relations expense, Edison electric institute dues, other membership dues, service company billings, interest synchronization, adjustment to income tax expense for parent company debt, vegetation management program expense, vehicle fuel expense, normalize remodeling expense, estimated property tax increases and income tax expense.
- Project Manager and Expert Witness in the review of the rate request of Pennsylvania American Water Company. Issues addressed in testimony included: accumulated deferred income taxes-repairs and maintenance, cash working capital expenses, income tax expense, consolidated tax savings, rate case expense, eliminated items, inflation adjustment, purchased power expense, salaries and wage expense, payroll tax expense, 401(k) and defined contribution plan expense, 2010 cost of removal/negative net salvage, depreciation expense (ASL vs. ELG), capitalization rate, interest synchronization and Winona Lakes availability revenue.
- Project Manager and Expert Witness in the review of West Virginia American Water Company's application to increase its rates. Issues addressed in Mr. Smith's testimony included: terminal plant, accumulated depreciation, cash working capital, tax savings from major tax accounting change, depreciation expense, post-test year pay increases, unfilled positions/vacancies, incentive compensation expense, stock based compensation expense, defined benefit plan pension expense,

affiliate management fees, purchased power, rate case, insurance other than group expense, payroll tax expense, advertising expense, income tax expense-interest synchronization, consolidated income tax savings adjustment, short term debt, interest on long-term debt, and comments on Baryenbruch Study.

- Project Manager in the 2012 evaluation and audit of California Water Service Company's General Office, unregulated activities, cost allocation methods and affiliate transactions, along with an analysis of California Water Service Company's general rate case test year estimates for the General Office. Issues addressed in the report included: cost allocations, general office revenues and expenses, overhead rates and time reporting and labor expense.
- Key Project Member in the evaluation and audit of Golden State Water Company's General Office, unregulated activities, cost allocation methods and affiliate transactions, along with an analysis of Golden State Water Company's general rate case test year estimates for the General Office. Issues addressed in the report included: cost allocations, general office revenues and expenses, centralized operations support, overhead rates and time reporting and labor expense.
- Key Project Member in the 2007 evaluation and audit of California Water Service Company's General Office, unregulated activities, cost allocation methods and affiliate transactions, along with an analysis of California Water Service Company's general rate case test year estimates for the General Office. Issues addressed included: cost allocations and allocations to unregulated activities, changes in methodology for an allocation factor, reduction to proposed employee levels, property insurance, workers compensation insurance, injuries and damages, outside services, plant additions, IS projects, and working capital.
- Project Member in the review of the rate request of Virginia-American Water Company. Issues addressed included: tank painting, customer advances, contributions in aid of construction, rate base update, reverse VAWC net plant adjustments beyond the test year, allowance for average rate year non-revenue producing CWIP, allocate utility plant and accumulated depreciation between districts, materials and supplies, miscellaneous operating reserves, accrued cost of removal/FAS 143, revenue annualization, leased vehicles, rate case expense, lobbying expense, payroll expense, payroll tax expense, employee benefits expense, donations, annualized depreciation expense, depreciation expense on allocated plant, interest synchronization, and income tax expense.
- Project team member in the review of Appalachian Power Company and Wheeling Power Company's rate request. Issues addressed by Larkin & Associates included: utility plant held for future use, prior period accumulated depreciation, prepayments, cash working capital, inactive to zero usage material and supplies inventory, self funded reserve accruals, rate base related asset retirement obligation adjustments, pole rental expense, remodeling expense, airplane costs, club initiation fees, written off obsolete inventory, incentive compensation, rate case expense, life insurance premiums, public relations expense, Edison Electric Institute Dues, Other Membership Dues, Three-Year Amortization from Loss on Sale of Bluefield and Wheeling Office Buildings, Amortization of Deferred RTO Formation, Service Company Billings, Institutional Advertising Expense, Interest on Customer Deposits, Expanded Net Energy Cost (ENEC), T&D Management, Consolidated Income Taxes, Interest Synchronization, Depreciation & Amortization Related to Asset Retirement Obligations, Maintenance of Boiler Plant Account 512, Maintenance of Electric Plant Account 513, Income Tax Expense.

- Project Team Member in the Financial and Management/Performance Audit of the Fuel and Purchased Power Rider of the Cincinnati Gas & Electric Company with Energy Ventures Analysis, Inc. (EVA) Larkin & Associates focused on the Financial Audit of CG&E's Fuel, Economy Purchased Power and Emission Allowance Component (FPP Component) for the audit period of January through June, 2005. EVA and Larkin & Associates issued a report detailing their findings and conclusions.
- Project Member in the detailed review and verification of preconstruction costs recorded by MPC through March 31, 2009 related to the Kemper County Integrated Gas Combined Cycle plant. Larkin reviewed a stratified sample of MPC's \$50,470,935 recorded preconstruction costs. Larkin's review revealed that \$4,470,098 of the preconstruction costs were inadequately documented, questionable or inappropriate and recommended removal from the Company's preconstruction regulatory deferral account balance. Some of the costs Larkin recommended removing were related to MPC's service company affiliate Southern Company Services. The Commission adopted Larkin's recommended adjustment in its April 29, 2010 Order.
- Project Member in the review of Delmarva Power and Light Company's request for an increase in rates. Testimony addressed the following issues: Pension Regulatory Asset, Unamortized Regulatory Commission Expense, CWIP, CWC, AMI Rate Base Revisions, AMI Deferred Costs, Amortization of Pension Regulatory Asset, Normalized Pension Expense for Ratemaking Purposes, Regulatory Commission Expense, Wage and Salary Expense, Payroll Tax Expense, Non-Executive Incentive Compensation Expense, Executive Compensation Expense, Stock-Based Compensation Expense, SERP, AFUDC, Interest Synchronization, Membership and Industry Association Dues, Employee Benefits, AMI Expense Revisions, AMI Deferred Costs, Gas Decoupling Customer Education Expense, Meals and Entertainment Expense, O&M Expense Increases for AMI-Related Labor Costs, Normalized Uncollectibles Expense Methodology, Rider VM, Utility Facility Relocation Charge Rider, Affiliated Charge Review Outside of a Rate Case.
- Project Member in the review of Mountaineer Gas Company's request for an increase in rates. Testimony focused on the following issues: Gas in Storage, Pension and OPEB Liabilities, Unrecovered Gas Costs, Cash Working Capital, Assets Transferred from Gas Services, ADIT, Self-Funded Reserve, Accounts Payable Related to Materials and Supplies, Weather Normalization, Transportation Revenue, Revenue and Cost of Gas for New PGA Rates, Miscellaneous Revenue, Uncollectibles, OPEB Expense, Payroll Expense, Payroll Tax Expense, 401K Match for New Employees, Employee Benefits, Interest on Customer Deposits, Rate Case Expense, Interest Synchronization, Industry Association Dues, Injuries and Damages Expense, Management Fees, and Income Tax Expense.
- Project Member in the review of Southern Connecticut Gas' request for a rate increase. Issues addressed by Larkin & Associates included: Pipe Replacement and Accelerated Pipe Replacement Programs, new business mains and services, Meters, Service Regulators and Installations, Meter Relocation Program, Matching Payment Plan Deferral, Cash Working Capital, Environmental Remediation Costs, Payroll, Incentive Compensation, Overtime and Expense Percentage, Stock Options, Payroll Tax Expense, Non-Hardship Uncollectibles Expense, Hardship Uncollectibles Expense, Matching Payment Plan Expense, Non-Hardship Uncollectibles Write-Off, Outbound Dialing Vendor, Gross Revenue Conversion Factor, Non-Qualified Pension Plans, Insurance Expense – Self-Insured Claims, USSC and EEMC Charges, Rate Case Expense, DPUC Assessment, Deferrals from DPUC Dockets, SpeedPay Transaction Fees/KUBRA, Service Transfer Costs, and Qualified Pension Plan.

- Project Member in the review of Connecticut Natural Gas' request for a rate increase. Issues addressed by Larkin & Associates included: gross revenue conversion factor, late payment charge revenues, non-hardship uncollectibles, payroll expense, payroll tax expense, qualified pension plans, non-qualified pension plans, outbound dialing vendor, insurance expense-self insured claims, injuries and damages reserve, service change-over costs, meter reading-other general expenses, KUBRA transaction fees/credit card bank fees, rate case expense, affiliate charges, environmental remediation costs, cash working capital, pipeline replacement program plant additions, accelerated pipe replacement program, new business plant additions, meters/service regulators/installations plant additions, meter relocation program plant additions, depreciation expense, and depreciation cost study amortization.
- Project Member in the review of UNS Gas' General Rate Application. Issues addressed in testimony included: Return on Fair Value Rate Base, Construction Work in Progress/Post Test Year Plant, Customer Advances for Construction, Prepayments, Cash Working Capital, Customer Deposits, Accumulated Deferred Income Taxes, Reconstruction Cost New Depreciated Rate Base, Revenue Annualization, Depreciation & Property Taxes for CWIP/Post Test Year Plant, Incentive Compensation Expense, Stock-Based Compensation Expense, Supplemental Executive Retirement Plan Expense, American Gas Association Dues, Outside Legal Expense, Fleet Fuel Expense, Rate Case Expense, Interest Synchronization, Property Tax Expense, and 2010 Pay Increase.
- Project Member in the review of the Application of Dominion Hope for a rate increase. The issues addressed in testimony include: Utility Plant in Service, Intangible Plant Assets, Accumulated Provision for Depreciation, Working Capital, ADIT – Liberalized Depreciation, ADIT, M&S for Gas Storage under the WACOG Methodology, Hold Harmless Ratemaking Adjustment, Pension Expense, Depreciation Expense, Property Tax Expense, Worker's Compensation Expense, Uncollectibles Expense, Out of Period Gasoline Expense, Payroll Expense, Payroll Tax Expense, Employee Benefits, Interest on Customer Deposits, Rent Expense, Consolidated Income Taxes, Interest Synchronization, LIFO to WACOG Storage Accounting, Membership and Industry Association Dues, Depreciation Expense Related to Intangible Plant Assets, OPEB Expense, DRS Service Charges, Agency Revenues, Test Year Revenues, and Adjust Income Taxes in Company Addendum.
- Project member in the review of Southwest Gas Corporation's General Rate Application. Issues addressed in testimony by Larkin & Associates included: Return on Fair Value Rate Base, Yuma Manors Pipe Replacement, Customer Advances for Construction, Working Capital, Cash Working Capital, Customer Deposits, Miscellaneous Accumulated Deferred Income Tax, Account 190, New Intangible Plant Placed Into Service By December 31, 2007, Adjustments to Reconstruction Cost New Depreciated Rate Base, Trended RCND Amount for Accumulated Deferred Income Taxes, Yuma Manors Depreciation and Property Tax Expense, Gain on Sale of Property in Cave Creek, Management Incentive Program Expense, Stock-Based Compensation (Other than MIP), Supplemental Executive Retirement Plan Expense, American Gas Association Dues, Transmission Integrity Management Program, A&G Expenses - Annualized Paiute Allocation, Interest on Customer Deposits, Interest Synchronization, Flow-back of Excess Deferred Taxes, Injuries and Damages, Leased Aircraft Operating Costs, El Paso Pipeline Rate Case Litigation Cost, and Annualized Amortization for New Intangible Plant.
- Project member in the review of UNS Gas' General Rate Application. Issues discussed in Mr. Smith's testimony included construction work-in-progress, Global Information System (GIS) deferral, cash working capital, accumulated deferred income tax, revenue annualization, weather

normalization, bad debt expense, depreciation and property taxes for CWIP, amortization of deferred GIS cost, incentive compensation and supplemental executive retirement program, emergency bill assistance expense, nonrecurring severance payment expense, overtime payroll expense, payroll tax expense, nonrecurring FERC rate case legal expense, property tax expense, workers compensation expense, membership and industry association dues, fleet fuel expense, postage expense, interest synchronization, depreciation rates, and changes to rules and regulations.

- Project member in the review of Arizona Public Service Company's Application for an Interim Increase in rates. Issues addressed in Mr. Smith's testimony included: the interim rate relief requested by APS, criteria for interim rate relief, ordinary regulatory lag does not justify APS' requested interim rate relief, alleged emergency circumstances, whether APS requires an interim rate increase during the processing of its general rate case, an alternative basis for determining an amount of interim rate increase for APS should the Commission be inclined to grant an increase, and rate design.
- Project member in the review of Tucson Electric Power Company's General Rate Application. Issues addressed in testimony included: Depreciation Rates, Plant Held for Future Use, Luna Plant Facility, Luna Plant Facility Accumulated Deferred Income Taxes, "Implementation Cost Regulatory Asset", Working Capital, Fuel Inventory, Accumulated Depreciation and ADIT Related to Cost of Removal, Accumulated Depreciation Related to Unauthorized Depreciation Rate Changes, Miscellaneous Accumulated Deferred Income Tax, Account 190, Other Deferred Credits, Customer Care & Billing System, Springerville Unit 1, Luna Facility Depreciation and Property Tax Expense, San Juan Coal Contract, Bad Debt Expense, Edison Electric Institute Dues, Incentive Compensation, Supplemental Executive Retirement Program Expense, Workers' Compensation Expense, Short-Term Sales, Wholesale Trading Activity, Gain on Sale of SO2 Emission Allowances, Property Tax Expense Interest Synchronization, Depreciation Rates Adjustment, Customer Care & Billing System, Markup Above Cost for Charges from Affiliate, Southwest Energy Services, PPFAC Adjustment, Postage Expense, Miscellaneous Service Revenue, Cash Working Capital, Normalize Affiliate Charges to TEP, Legal Expense Related to Motion to Amend Decision No . 62103, Legal Expense Related to California Proceedings, West Connect Charges Related to Regulatory Asset, Other TEP Changes to Operating Income and Rate Base, Purchased Power and Fuel Adjustment Clause, TEP's Historical Misuse of Previous Fuel Adjustment Mechanism, Staffs Proposed PPFAC, TEP's Proposed PPFAC , Costs to Be Included in the PPFAC, Credits to PPFAC Costs Effective Date for PPFAC, PPFAC Forward-Looking and True-Up Components, Carrying Costs on PPFAC bank balance, Filing and Reporting Requirements, Whether Sharing and Cap Provisions Should be Imposed, Requirement for Commission approval of PPFAC, and rate changes.
- Project Member in the review of UNS Electric, Inc.'s revenue requirement and selected other issues, including new depreciation rates, and rules and regulation changes proposed by the Company. Issues discussed in Mr. Smith's testimony included construction work-in-process, plant in service addition subject to reimbursement, cash working capital, accumulated deferred income tax, revenue adjustment for CARES discount, depreciation and property taxes for CWIP, depreciation and property taxes for CWIP found to be in service in the test year, fleet fuel expense, postage expense, normalize injuries and damages, incentive compensation, supplemental executive retirement program expense, stock based compensation, property tax expense, rate case expense, Edison Electric Institute Dues, other membership and industry association dues, interest synchronization, depreciation rates correction, emergency bill assistance expense, markup above cost for charges from affiliate, Southwest Energy Services, depreciation rates, changes to

purchased power and fuel adjustment clause, and the Company's proposed ratemaking treatment for a new peaking unit, Black Mountain Generating Station.

- Project Member in the review of Potomac Electric Power Company's request for an increase in rates. Testimony focused on the following issues: test year, rate base, 13-month average rate base, construction work in progress, cash working capital, revenues, uncollectible expense, storm damage costs, industry contributions & membership dues, credit facility start up costs, directors & officers liability insurance, pension expense, prepaid pension asset/prepaid OPEB liability, wages & salaries adjustment, correction to employee incentive plan adjustment, employee benefits expense, and PEPCO employee club costs.
- Project Member in the review of the application for an increase in rates filed by Questar Gas Company. Issues addressed included: conversion of Company's filing to an average test year, contractor retainage, banked vacations, annualization of customers and revenues resulting from mergers with two other gas companies, gain on sale of property, increase in industrial customer revenues, allocation factors, employee levels, advertising, postage, dues, amortization expense, incentive compensation, outside services, office closures, uncollectibles and rate of return adjustment from affiliates. This case settled prior to hearings.
- Project Member in the review of Florida Public Utilities Company's request for an increase in rates. Issues addressed included: construction work in progress, allocation adjustments associated with discontinued operations, retiree medical costs, stock issuance expense, payroll outsourcing costs, tree trimming crew costs, consulting fees, audit exceptions, projection factors storm reserve accrual, economic development costs, accumulated deferred income taxes, and contributions associated with addition of new large industrial customers. The case settled after testimony was filed and prior to hearings.
- Project Member in the review of the rate increase request by Utilities, Inc. for a rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties. Issues reviewed included: revenues – index rate increase annualizations corrections, amortization of non-recurring costs – TV video inspection, amortization on books for retired WWT plants - Summertree and Weatherfield, employee costs, purchase water expense – Oakland Shores, Uncollectible Expense – Weatherfield, excessive lost and unaccounted for water, excessive inflow and infiltration, Lincoln Heights Purchase Wastewater Treatment Expense, non-used and useful facilities, removal of non-used and useful wastewater treatment plants, and rate of return – return on equity penalty.
- Project Member in a review of Washington Gas Light Company's proposed construction budget and incentive rate plan. Issues addressed by Larkin & Associates included: reasonableness of the construction budget and budget variances, reasonableness of the Company's proposed incentive rate plan (IRP), whether incentives above and beyond traditional rate of return regulation are needed, impact on ratepayers of proposed IRP, customer service quality standards, experience in other jurisdiction with alternative rate forms of recommendations. Ultimately, the Commission agreed with our recommendations that the proposed IRP be denied.
- Project Member in the review of a request by PacifiCorp for an increase in rates. As part of the analysis, Larkin & Associates also reviewed and addressed the Company's request to modify the test year provisions that had long been adopted and approved by the Commission. This case settled prior to filing testimony; however, schedules and exhibits were completed and submitted in order to facilitate settlement negotiations. Larkin & Associates was actively involved in the settlement discussions. Issues addressed by Larkin & Associates in our exhibits and schedules

include: major plant additions including a transmission replacement and upgrade program, accounts receivable from associated company, cash working capital, increased revenues from system expansion and upgrade, change in method of accounting for unbilled revenues, normalization of overhaul expense, payroll expense including employee level impacts, incentive compensation, employee benefits, costs of canal failure, depreciation on retired assets, write-off of canceled projects, insurance expense, property taxes, IRS audit settlement adjustments, and amortization of costs associated with early retirement of Company owned coal mine.

- Project Member in the review of Connecticut Light & Power Company's request for an amendment in rates for the period 2004 through 2007. Issues addressed included: adjustments to CL&P's proposed initiatives, deferred assets, Storm Damage Accrual reserves, working capital, revenues, recovery of six specific items identified by the Company as exogenous costs under its Incentive Rate Plan. Larkin & Associates testimony first addressed the appropriate definition and specific qualifications for items to be considered as exogenous costs under the Company's incentive rate plan. The testimony then addressed the following six specific items for which the Company was requesting an increase in rates for exogenous cost recovery: uncollectible expense, pension expense, other post retirement benefit expense, personal property taxes, raise in Connecticut Corporate Business Tax rate and Three-Way Payment Plan deferrals.
- Project Member in the audit of the Rockland Electric Company's restructuring related deferred balances that have been accruing by the Utility in the course of its implementation of various New Jersey Board of Public Utilities Orders providing for rate reductions and other requirements, pursuant to the Electric Discount and Energy Competition Act (EDECA), N.J.S.A. 48:3-49 et seq. The audit is separated into two phases. Phase I covered the period of August 1, 1999 through July 31, 2002. Larkin & Associates audited the deferred accounts, transactions and supporting calculations/documentation for this period to determine whether the Utility's Deferred Balances are correct and include only those costs that are reasonable, prudently incurred, accurately calculated, correctly recorded and in compliance with all applicable Board Orders. Subcontractor, Synapse Energy Economics analyzed prudence issues relating to the Utility's purchase of power at reasonable prices consistent with market conditions in the competitive wholesale marketplace and consistent with appropriate hedging techniques, along with mitigation efforts with respect to above-market non-utility generation contract costs during the Transition Period. Larkin & Associates and Synapse Energy Economics issued a combined report discussing their findings and conclusions.
- Project team member in United Illuminating Company's rate case. Larkin & Associates was retained by the Connecticut Office of Consumer Counsel to address the calculation of the revenue requirement and adjustments to the calculations of rate base and net operating income presented in UI's filing. Larkin & Associates also addressed the sharing proportions that should be applied if the Department adopts a multi-year rate plan for UI in this proceeding. Issues discussed in testimony included rate plan, over-earnings sharing proportions, subsidiary income tax expense, starting point for 2002 rate year rate base, customer deposits, materials and supplies, rate-a-meter timers, injuries and damages reserve, severance expense, rate case expense, other O&M expense increase, ADIT on pension liability and Bad Debt reserve, accrued vacation and related ADIT, Steel Point remediation, depreciation expense, income tax expense correction, interest synchronization, property tax expense, accelerated amortization.
- Project team member in the review of Citizens Utilities Company's application for a rate increase. Issues addressed in testimony included: an overall financial summary, accounting concerns, rate base (interim accumulated depreciation, rate year accumulated depreciation, used

and useful, deferred income taxes, deferred costs, IRP Twenty Year Plan, PCB Costs, 1999 Windstorm and Hurricane Floyd costs, HQ Arbitration, Working capital), operating income (revenue adjustments, SAO expense, DAO expense, PSO expense, Rate Case Expense, Legal and Regulatory, Income Tax Expense, Tree Trimming) and summary of accounting problems.

- Key project team member in the annual audit of Lake State Railway and Huron Leasing. Duties included verification of cash receipts and disbursements, payroll, and inventory.

A complete list of cases in which Mr. Dady has participated will be provided upon request.

Education

- Davenport University, Dearborn, MI
Bachelor of Business Administration: Accounting
March 2001 - Graduated with high honors
- Walsh College, Troy, MI
Master of Science: Accounting
December 2006
- Certified Public Accounting Certificate 2007, Continuing Professional Education Necessary to Maintain CPA License

Professional Affiliations

- Michigan Association of Certified Public Accountants

Partial list of utility cases participated in:

E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No. 07-186	Chesapeake Utilities Corporation (Delaware PSC)
Docket No. UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)

E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)
Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)

15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015-0302	Missouri American Water Company (Missouri PSC)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P	
(Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)
Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)

Docket No. D2018.4.22 18-0573-W-42T & 18- 0576-S-42T 18-0646-E-42T & 18-0645 E-D	Montana-Dakota Utilities Co. (Montana PSC) West Virginia-American Water Company (West Virginia PSC) Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT R-2018-3003558, R-2018- 3003561	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
T-03214-17-0305	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC) Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. D2018.9.60 Docket No. 4890 PUR-2018-00131 EL18-152-000	Montana-Dakota Utilities Co. (Montana PSC) Narragansett Bay Commission (Rhode Island PUC) Columbia Gas of Virginia (Virginia SCC) Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)
A-2018-3006061, A-2018- 3006062 and A-2018- 3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. D2018.2.12 Docket No. 42310 U-18-102	NorthWestern Energy (Montana PSC) Georgia Power Company – Integrated Resource Plan (Georgia PSC) Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
PUC Docket No. 49494 19-0316-G-42T 19-0051-EL-RDR	AEP Texas, Inc. (Texas PUC) Mountaineer Gas Company (West Virginia PSC) Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
A-2018-3006061, A-2018-3006062, and A-2018-3006063	Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, and Peoples Gas Company LLC (Pennsylvania PUC)
ER-18-1182-001 E-01933A-19-0028 G-01551A-19-0055 2018-UN-205 W-03039A-17-0295, W-03039A-19-0092, and WS-01303A-19-0092 Docket No. 4975	System Energy Resources, Inc. (FERC) Tuscon Electric Power Company (Arizona CC) Southwest Gas Corporation (Arizona CC) Entergy Mississippi, LLC (Mississippi PSC)
A-2019-3014248	Brooke Water, LLC and EPCOR Water Arizona (Arizona CC) Block Island Utility District d/b/a Block Island Power Company (Rhode Island PUC)
Docket No. 4994 19-0791-GA-ALT	Pennsylvania-American Water Company and Wastewater System Assets of Kane Borough (Pennsylvania PUC) Providence Water Supply Board (Rhode Island PUC) Plant in Service and Capital Spending Prudence Audit of Duke Energy Ohio (Ohio PUC)
Docket No. 42516 20200070-EI 20200071-EI	Georgia Power Company (Georgia PSC) Gulf Power Company (Florida PSC) Florida Power & Light Company (Florida PSC)

20200092-EI	Florida Power & Light Company and Gulf Power Company (Florida PSC)
20-GREC-01	Fitchburg Gas and Electric Light Company d/b/a Unitil (Massachusetts DPU)
20-GREC-03	Boston Gas Company and Colonial Gas Company d/b/a National Grid (Massachusetts DPU)
20-GREC-04	Liberty Utilities (New England Natural Gas Company) Corp d/b/a Liberty Utilities (Massachusetts DPU)
PUR-2020-00015	Appalachian Power Company (Virginia SCC)
20-0414-G-390P	Hope Gas, Inc. dba Dominion Energy West Virginia (West Virginia PSC)
2019.1.101	NorthWestern Energy (Montana PSC)
A-2019-3015173	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority (Pennsylvania PUC)
R-2020-3019369 and	
R-2020-3019371	Pennsylvania American Water Company (Pennsylvania PUC)
2020.06.076	Montana-Dakota Utilities Co. (Montana PSC)
2020.05.055	Montana-Dakota Utilities Co. (Montana PSC)
2020.05.066	NorthWestern Energy (Montana PSC)
PUR-2020-00169	Virginia Electric and Power Company (Virginia SCC)
20-0746-G-42T	Hope Gas, Inc., d/b/a Dominion Energy West Virginia (West Virginia PSC)
20-553-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Rider of the Dayton Power and Light Company (Ohio PUC)
E-01345A-19-0236	Arizona Public Service Company (Arizona CC)
Docket No. 20-01-31	The Southern New England Telephone Company d/b/a Frontier Communications of Connecticut (SNET) (Connecticut PURA)
P-2020-3021191	Peoples Natural Gas Company LLC (Pennsylvania PUC)
A-2021-3026523,	
A-2021-3026515, and	
A-2021-3026522	Joint Application of Veolia Environnement S.A., Veolia North America, Inc., SUEZ S.A., SUEZ Water Pennsylvania Inc. and SUEZ Water Bethel Inc. (Pennsylvania PUC)
A-2021-3026794 and	
A-2021-3026796	Joint Application of Peoples Natural Gas Company LLC and Peoples Gas Company (Pennsylvania PUC)
A-2021-3026774 and	
A-2021-3026775	Joint Application of Aqua Pennsylvania Inc., and Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
A-2021-3024267	Aqua Pennsylvania Wastewater Inc. (Pennsylvania PUC)
R-2021-3027385 and	
R-2021-3027386	Aqua Pennsylvania, Inc, and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
21-0595-WW-AIR	Aqua Ohio, Inc. (Ohio PUC)
21-0596-ST-AIR	Aqua Ohio Wastewater, Inc. (Ohio PUC)
21-0369-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-01345A-21-0056	Fuel and Purchased Power Audit of Arizona Public Service Company (Arizona CC)
SW-20445A-20-0214 et al	Global Water Resources, Inc. (Arizona CC)
PUR-2021-00058	Virginia Electric and Power Company (Virginia SCC)
Docket No. 44160	Georgia Power Company Integrated Resource Plan (Georgia PSC)
22-620-GA-RDR	Plant in Service and Capital Spending Prudence Audit of Vectren Energy Delivery of Ohio, Inc. d/b/a CenterPoint Energy Ohio (Ohio PUC)
PUR-2021-00255	Virginia-American Water Company (Virginia SCC)
RP19-3-003	El Paso Natural Gas Company, LLC (FERC)
22-0304-E-P	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)

R-2022-3031672 and R-2022-3031673 22-0294-G-PC	Pennsylvania-American Water Company (Pennsylvania PUC) Hope Gas, Inc., dba Dominion Energy West Virginia and Hope Gas Holdings (West Virginia PSC)
G-01551A-21-0368 2022-06-064 20220067-GU	Southwest Gas Corporation (Arizona CC) NorthWestern Energy (Montana PSC) Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Fort Meade, and Florida Public Utilities Company – Indiantown Division (Florida PSC)
PUR-2020-00015 22-0393-E-ENEC	Appalachian Power Company – Remand (Virginia SCC) Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
E-01773A-21-0298 Docket No. 44280 FTC-01/2021-BL&P- RRA-20211004	Arizona Electric Power Cooperative, Inc. (Arizona CC) Georgia Power Company (Georgia PSC)
A-2019-3015173	Barbados Light & Power Company Limited (Barbados Fair Trading Commission)
2022.07.078 2022-UN-86/2022-UN-087 E-01933A-22-0107 A-2022-3035298, A-2022-3035299, A-2022-3035490, A-2022-3035492	Aqua Pennsylvania Wastewater Inc. and Wastewater System Assets of the Delaware County Regional Water Quality Control Authority - Remand (Pennsylvania PUC) NorthWestern Energy (Montana PSC) Great River Utility Operating Company, LLC (Mississippi PSC) Tucson Electric Power Company (Arizona CC)
PUR-2022-00052 22-47-WW E-01345A-22-0144 E-04204A-22-0251 PUR-2023-00002 22-1094-WW-AIR 22-1096-ST-AIR A-2022-3037047, et al.	Manwalamink Water Company, Manwalamink Sewer Company, NextEra Water Pennsylvania, LLC (Pennsylvania PUC) Virginia Natural Gas, Inc. (Virginia SCC) Narragansett Bay Commission (Rhode Island PUC) Arizona Public Service Company (Arizona CC) UNS Electric, Inc. (Arizona CC) Appalachian Power Company (Virginia SCC) Aqua Ohio, Inc. (Ohio PUC) Aqua Ohio Wastewater, Inc. (Ohio PUC) Pennsylvania-American Water Company, Butler Area Sewer Authority (Pennsylvania PUC)
PUR-2023-00067 and PUR-2023-00112	Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
Docket No. 54634 23-0089-EL-RDR 23-0280-G-42T 2022-0208 PUR-2023-00101	Southwestern Public Service Company (Texas PUC) Duke Energy Ohio, Inc. (Ohio PUC) Mountaineer Gas Company (West Virginia PSC) Kauai Island Utility Cooperative (Hawaii PUC) Virginia Electric and Power Company d/b/a Dominion Energy Virginia (Virginia SCC)
23-0383-W-42T and 23-0384-S-42T 23-0460-E-42T	West Virginia-American Water Company (West Virginia PSC) Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
R-2023-3043189& R-2023-3043190 T-03214A-23-0250	Pennsylvania-American Water Company (Pennsylvania PUC) Citizens Telecommunications of the White Mountains, Inc., dba Frontier Communications of the White Mountains (Arizona CC)
PUR-2023-00194 G-01551A-23-0341	Virginia-American Water Company (Virginia SCC) Southwest Gas Corporation (Arizona CC)

PUR-2024-00024	Appalachian Power Company (Virginia SCC)
R-2024-3047822 &	
R-2024-3047824	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
24-14-EL	Pascoag Utility District (Rhode Island PUC)
2022-0140	Hawaii Water Service Company, Inc. (Hawaii PUC)
24-0185-EL-RDR	AEP Ohio Company, d/b/a AEP-Ohio (Ohio PUC)
20240068-WS	Sunshine Water Services Company (Florida PSC)
W-02074A-23-0337,	
W-02465A-23-0338,	
WS-02060A-23-0339,	
WS-02676A-23-0340,	
WS-02676A-24-0029,	
W-02074A-24-0030,	
W-02465A-24-0031, and	
WS-02060A-24-0033	Liberty Utilities (Arizona CC)
2024.08.088	NorthWestern Energy, Energy West Montana, Inc., and Cut Bank Gas Company (Montana PSC)
2024.05.053	NorthWestern Energy (Montana PSC)
2024-0158	The Gas Company, LLC dba Hawaii Gas (Hawaii PUC)
24-41-WW	Narragansett Bay Commission (Rhode Island PUC)
E-01773A-24-0220	Arizona Electric Power Cooperative, Inc. (Arizona CC)
24-51-WW	Providence Water Supply Board (Rhode Island PUC)
2024-0224	Waikoloa Resort Utilities, Inc., dba West Hawaii Utility Company, Waikoloa Sanitary Sewer Company, Inc., dba West Hawaii Sewer Company, Waikoloa Water Co., Inc., dba West Hawaii Water Company (Hawaii PUC)
56002 & 56003	Georgia Power Company Integrated Resource Plan (Georgia PSC)
24-0854-E-42T	Appalachian Power Company and Wheeling Power Company (WV PSC)
G-04204A-24-0237	UNS Gas, Inc. (Arizona CC)
PUR-2025-00058	Virginia Electric and Power Company (Virginia SCC)
P-24-013	Kenai Beluga Pipeline, LLC (Regulatory Commission of Alaska)

PC Ex. 62.03

Schedule of Applicants' adjusted base rate revenue requirements –
Optimal Budgets

Line No.	Description	FY 2026 (A)	FY 2027 (B)	FY 2028 (C)
Revenues from Sales of Electric Energy				
1	Fuel & Purchased Power Revenue	\$ 2,436,713,300	\$ 2,363,810,018	\$ 2,312,631,997
2	Basic Revenues	\$ 1,179,202,427	\$ 1,153,897,330	\$ 1,138,445,035
3	CILT & Subsidies (Contra-Revenue)	\$ 320,077,800	\$ 320,077,800	\$ 320,077,800
4	Total Revenues from Sales of Electric Energy	<u>\$ 3,935,993,527</u>	<u>\$ 3,837,785,148</u>	<u>\$ 3,771,154,832</u>
Other Income				
5	Total Consolidated Revenues	\$ 84,404,196	\$ 87,341,462	\$ 90,380,945
6	CILT & Subsidies (Contra-Revenue)	\$ 4,020,397,723	\$ 3,925,126,610	\$ 3,861,535,777
		\$ 320,077,800	\$ 320,077,800	\$ 320,077,800
7	Total Net Revenues	<u>\$ 3,700,319,923</u>	<u>\$ 3,605,048,810</u>	<u>\$ 3,541,457,977</u>
Expenses				
Fuel and Purchased Power Expenses				
8	Fuel	\$ 1,710,960,029	\$ 1,659,770,338	\$ 1,623,835,233
9	Purchased Power - Conventional	\$ 575,691,701	\$ 558,467,757	\$ 546,376,568
10	Purchased Power - Renewable	\$ 150,061,570	\$ 145,571,924	\$ 142,420,197
11	Total Fuel & Purchase Power Expenses	<u>\$ 2,436,713,300</u>	<u>\$ 2,363,810,018</u>	<u>\$ 2,312,631,997</u>
Operating & Maintenance Expenses				
Labor Operating Expenses				
12	Salaries & Wages	\$ 346,654,731	\$ 379,495,389	\$ 405,359,946
13	Pension & Benefits	\$ 141,939,687	\$ 155,680,399	\$ 166,577,335
14	Overtime Pay	\$ 36,330,782	\$ 39,652,110	\$ 42,371,879
15	Overtime Benefits	\$ 104,619	\$ 106,327	\$ 108,125
16	Total Labor Operating Expenses	<u>\$ 525,029,819</u>	<u>\$ 574,934,225</u>	<u>\$ 614,417,285</u>
Non-Labor / Other Operating Expenses				
17	Materials & Supplies	\$ 87,607,503	\$ 82,852,259	\$ 86,678,426
18	Transportation, Per Diem, and Mileage	\$ 34,087,970	\$ 38,410,649	\$ 41,206,350
19	Property & Casualty Insurance	\$ 67,993,442	\$ 74,158,614	\$ 75,359,045
20	Retiree Medical Benefits	\$ 7,950,000	\$ 8,347,500	\$ 8,764,875
21	Security	\$ 18,313,760	\$ 18,647,777	\$ 19,338,165
22	IT Service Agreements	\$ 68,206,819	\$ 98,143,479	\$ 116,498,113
23	Banking Services	\$ 2,050,000	\$ 2,152,500	\$ 2,260,125
24	Utilities & Rents	\$ 44,407,632	\$ 45,412,745	\$ 46,633,872
25	Legal Services	\$ 29,699,197	\$ 31,105,740	\$ 32,207,944
26	Communications Expenses	\$ 3,559,177	\$ 2,966,872	\$ 3,120,702
27	Professional & Technical Outsourced Services	\$ 303,317,828	\$ 343,813,093	\$ 368,105,711
28	Vegetation Management	\$ 125,000,000	\$ 131,250,000	\$ 137,812,500
29	Regulation and Environmental Inspection	\$ 8,325,250	\$ 8,171,875	\$ 8,171,875
30	External Audit Services	\$ 6,286,275	\$ 8,711,275	\$ 6,336,475
31	Plant Maintenance Services	\$ 30,256,412	\$ 31,450,747	\$ 33,295,261
32	Equipment, Inspections, Repairs & Other O&M	\$ 2,170,719	\$ 2,206,150	\$ 2,243,454
33	PREPA Restructuring & Title III	\$ 27,450,000	\$ 17,712,500	\$ 11,425,000
34	FOMB Advisor Costs allocated to PREPA	\$ 51,289,184	\$ 25,644,592	\$ 17,438,323
35	P3 Authority Transaction Costs	\$ -	\$ -	\$ -
36	Miscellaneous Expenses	\$ 17,766,675	\$ 17,444,964	\$ 18,213,539
37	Total Non-Labor / Other Operating Expenses	<u>\$ 935,737,843</u>	<u>\$ 988,603,332</u>	<u>\$ 1,035,109,755</u>
38	Total Operating Expenses	\$ 3,897,480,961	\$ 3,927,347,575	\$ 3,962,159,037
39	Share Services Agreement Impact	\$ 7,013,454	\$ 5,762,548	\$ 5,859,988
40	Total Operating Expenses, Adjusted	<u>\$ 3,904,494,415</u>	<u>\$ 3,933,110,123</u>	<u>\$ 3,968,019,025</u>
41	LUMA Fees	\$ 139,367,261	\$ 103,711,032	\$ 137,717,442
42	Bad Debt Expense	\$ 158,980,998	\$ 166,713,168	\$ 167,782,434
43	2% Reserve for Excess Expenditures	\$ 32,304,887	\$ 38,178,622	\$ 43,401,220
44	HoldCo General Civil Cases Settlement and Judgments	\$ 4,000,000	\$ -	\$ -
45	HoldCo Eminent Domain Cases Settlement and Judgments	\$ 6,500,000	\$ -	\$ -
46	HoldCo ERS Pension Funding Requirement	\$ 307,475,422	\$ 298,658,581	\$ 298,438,608
47	GridCo Storm Reserve Account	\$ 120,000,000	\$ 120,000,000	\$ -
48	GenCo Reserve Account	\$ 30,000,000	\$ 30,000,000	\$ 30,000,000
49	Genera Fixed Fees	\$ 26,585,154	\$ 27,621,330	\$ 28,697,890
50	Genera Performance Fees	\$ -	\$ -	\$ -
51	Total Other Expenses	<u>\$ 825,213,723</u>	<u>\$ 784,882,732</u>	<u>\$ 706,037,594</u>

Line No.	Description	FY 2026 (A)	FY 2027 (B)	FY 2028 (C)
	Maintenance Projects (Non-Federally Funded Capital Expenditures)			
52	GridCo	\$ 602,569,233	\$ 762,356,713	\$ 928,328,367
53	GenCo	\$ 290,965,353	\$ 292,183,946	\$ 277,698,776
54	HydroCo	\$ 8,382,150	\$ 5,969,160	\$ 5,767,160
55	HoldCo	\$ 2,065,000	\$ 770,000	\$ 270,000
56	Executive (General & Admin)	\$ -	\$ -	\$ -
57	Customer Service	\$ -	\$ -	\$ -
58	Planning and Environmental Protection	\$ -	\$ -	\$ -
59	Total Maintenance Projects	<u>\$ 903,981,737</u>	<u>\$ 1,061,279,819</u>	<u>\$ 1,212,064,303</u>
60	Federal Funding Cost Share (Commonwealth Match Obligation)	\$ 166,652,325	\$ 200,183,583	\$ 197,193,171
61	Total Non-F&PP O&M Expense	\$ 2,344,886,267	\$ 2,640,262,578	\$ 2,884,245,363
62	Total Revenue Requirement - Optimal Budget	<u>\$ 5,633,689,875</u>	<u>\$ 5,779,272,674</u>	<u>\$ 5,886,120,922</u>

Notes and Source

Cols. A-C: Amounts from LUMA's response to ROI PC-of-LUMA-FIN-2, Attachment 1

PC Ex. 62.04

Schedule of Applicants' adjusted base rate revenue requirements –
Constrained Budgets

Line No.	Description	FY 2026 (A)	FY 2027 (B)	FY 2028 (C)
Revenues from Sales of Electric Energy				
1	Fuel & Purchased Power Revenue	\$ 2,436,713,300	\$ 2,363,810,018	\$ 2,312,631,997
2	Basic Revenues	\$ 1,179,202,427	\$ 1,153,897,330	\$ 1,138,445,035
3	CILT & Subsidies (Contra-Revenue)	\$ 320,077,800	\$ 320,077,800	\$ 320,077,800
4	Total Revenues from Sales of Electric Energy	<u>\$ 3,935,993,527</u>	<u>\$ 3,837,785,148</u>	<u>\$ 3,771,154,832</u>
Other Income				
5	Total Consolidated Revenues	\$ 84,404,196	\$ 87,341,462	\$ 90,380,945
6	CILT & Subsidies (Contra-Revenue)	\$ 4,020,397,723	\$ 3,925,126,610	\$ 3,861,535,777
		\$ 320,077,800	\$ 320,077,800	\$ 320,077,800
7	Total Net Revenues	<u>\$ 3,700,319,923</u>	<u>\$ 3,605,048,810</u>	<u>\$ 3,541,457,977</u>
Expenses				
Fuel and Purchased Power Expenses				
8	Fuel	\$ 1,710,960,029	\$ 1,659,770,338	\$ 1,623,835,233
9	Purchased Power - Conventional	\$ 575,691,701	\$ 558,467,757	\$ 546,376,568
10	Purchased Power - Renewable	\$ 150,061,570	\$ 145,571,924	\$ 142,420,197
11	Total Fuel & Purchase Power Expenses	<u>\$ 2,436,713,300</u>	<u>\$ 2,363,810,018</u>	<u>\$ 2,312,631,997</u>
Operating & Maintenance Expenses				
Labor Operating Expenses				
12	Salaries & Wages	\$ 291,782,816	\$ 305,333,703	\$ 320,241,436
13	Pension & Benefits	\$ 122,663,209	\$ 128,508,151	\$ 134,949,159
14	Overtime Pay	\$ 28,637,895	\$ 29,973,811	\$ 31,442,838
15	Overtime Benefits	\$ 104,619	\$ 106,327	\$ 108,125
16	Total Labor Operating Expenses	<u>\$ 443,188,539</u>	<u>\$ 463,921,992</u>	<u>\$ 486,741,558</u>
Non-Labor / Other Operating Expenses				
17	Materials & Supplies	\$ 68,183,767	\$ 62,350,663	\$ 64,464,878
18	Transportation, Per Diem, and Mileage	\$ 20,689,111	\$ 21,603,895	\$ 21,756,491
19	Property & Casualty Insurance	\$ 67,993,442	\$ 74,148,114	\$ 75,348,020
20	Retiree Medical Benefits	\$ 7,950,000	\$ 8,347,500	\$ 8,764,875
21	Security	\$ 18,313,760	\$ 18,797,387	\$ 19,649,354
22	IT Service Agreements	\$ 59,703,416	\$ 92,174,238	\$ 110,060,847
23	Banking Services	\$ 2,050,000	\$ 2,152,500	\$ 2,260,125
24	Utilities & Rents	\$ 38,128,344	\$ 39,108,421	\$ 40,136,934
25	Legal Services	\$ 25,068,324	\$ 26,209,347	\$ 27,026,952
26	Communications Expenses	\$ 2,881,177	\$ 2,983,636	\$ 3,091,218
27	Professional & Technical Outsourced Services	\$ 240,752,067	\$ 277,180,855	\$ 298,522,177
28	Vegetation Management	\$ 70,700,000	\$ 125,000,000	\$ 131,250,000
29	Regulation and Environmental Inspection	\$ 8,325,250	\$ 8,171,875	\$ 8,171,875
30	External Audit Services	\$ 6,286,275	\$ 8,711,275	\$ 6,337,225
31	Plant Maintenance Services	\$ 22,692,309	\$ 23,588,060	\$ 24,971,445
32	Equipment, Inspections, Repairs & Other O&M	\$ 2,170,719	\$ 2,206,150	\$ 2,243,454
33	PREPA Restructuring & Title III	\$ 27,450,000	\$ 17,712,500	\$ 11,425,000
34	FOMB Advisor Costs allocated to PREPA	\$ 51,289,184	\$ 25,644,592	\$ 17,438,323
35	P3 Authority Transaction Costs	\$ -	\$ -	\$ -
36	Miscellaneous Expenses	\$ 14,099,663	\$ 13,900,277	\$ 14,651,542
37	Total Non-Labor / Other Operating Expenses	<u>\$ 754,726,808</u>	<u>\$ 849,991,286</u>	<u>\$ 887,570,736</u>
38	Total Operating Expenses	\$ 3,634,628,647	\$ 3,677,723,296	\$ 3,686,944,291
39	Share Services Agreement Impact	\$ 7,013,454	\$ 5,762,548	\$ 5,859,988
40	Total Operating Expenses, Adjusted	<u>\$ 3,641,642,101</u>	<u>\$ 3,683,485,845</u>	<u>\$ 3,692,804,278</u>
41	LUMA Fees	\$ 139,367,261	\$ 103,711,032	\$ 137,717,442
42	Bad Debt Expense	\$ 129,957,435	\$ 129,532,871	\$ 125,148,056
43	2% Reserve for Excess Expenditures	\$ 24,132,654	\$ 29,184,971	\$ 32,597,311
44	HoldCo General Civil Cases Settlement and Judgments	\$ 4,000,000	\$ -	\$ -
45	HoldCo Eminent Domain Cases Settlement and Judgments	\$ 6,500,000	\$ -	\$ -
46	HoldCo ERS Pension Funding Requirement	\$ 307,475,422	\$ 298,658,581	\$ 298,438,608
47	GridCo Storm Reserve Account	\$ 120,000,000	\$ 120,000,000	\$ -
48	GenCo Reserve Account	\$ -	\$ -	\$ -
49	Genera Fixed Fees	\$ 26,585,154	\$ 27,621,330	\$ 28,697,890
50	Genera Performance Fees	\$ -	\$ -	\$ -
51	Total Other Expenses	<u>\$ 758,017,926</u>	<u>\$ 708,708,784</u>	<u>\$ 622,599,306</u>

Line No.	Description	FY 2026 (A)	FY 2027 (B)	FY 2028 (C)
	Maintenance Projects (Non-Federally Funded Capital Expenditures)			
52	GridCo	\$ 398,491,970	\$ 504,027,570	\$ 603,716,331
53	GenCo	\$ 209,276,668	\$ 179,961,323	\$ 180,358,438
54	HydroCo	\$ 8,382,150	\$ 5,969,160	\$ 5,767,160
55	HoldCo	\$ 2,065,000	\$ 770,000	\$ 270,000
56	Executive (General & Admin)	\$ -	\$ -	\$ -
57	Customer Service	\$ -	\$ -	\$ -
58	Planning and Environmental Protection	\$ -	\$ -	\$ -
59	Total Maintenance Projects	<u>\$ 618,215,788</u>	<u>\$ 690,728,053</u>	<u>\$ 790,111,929</u>
60	Federal Funding Cost Share (Commonwealth Match Obligation)	\$ 166,652,325	\$ 200,183,583	\$ 197,193,171
61	Total Non-F&PP O&M Expense	\$ 1,785,927,783	\$ 1,989,001,312	\$ 2,153,343,280
62	Total Revenue Requirement - Optimal Budget	<u>\$ 5,017,875,815</u>	<u>\$ 5,082,922,682</u>	<u>\$ 5,105,515,514</u>

Notes and Source

Cols. A-C: Amounts from LUMA's response to ROI PC-of-LUMA-FIN-2, Attachment 1

PC Ex. 62.05

Florida Public Service Commission, Order PSC-2024-0503-PCO-
EI dated December 17, 2024 Approving Florida Power & Light
Company's Interim Storm Cost Recovery Charge, in FPSC Docket No.
20240149-EI

FILED 12/17/2024
DOCUMENT NO. 10261-2024
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for limited proceeding for
recovery of incremental storm restoration costs
related to Hurricanes Debby, Helene, and
Milton, by Florida Power & Light Company.

DOCKET NO. 20240149-EI
ORDER NO. PSC-2024-0503-PCO-EI
ISSUED: December 17, 2024

The following Commissioners participated in the disposition of this matter:

MIKE LA ROSA, Chairman
ART GRAHAM
GARY F. CLARK
ANDREW GILES FAY
GABRIELLA PASSIDOMO SMITH

ORDER APPROVING FLORIDA POWER & LIGHT COMPANY'S
INTERIM STORM COST RECOVERY CHARGE

BY THE COMMISSION:

BACKGROUND

On October 29, 2024, Florida Power & Light Company (FPL or Company) filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover \$1.2 billion for the incremental restoration costs related to Hurricanes Debby, Helene, and Milton, as well as the replenishment of its retail storm reserve. Included in the \$1.2 billion is interest charged on the unrecovered balance of storm restoration costs resulting from Hurricanes Debby, Helene, and Milton (collectively, "the Storms"). Pursuant to the 2021 Stipulation and Settlement Agreement approved by us in Order No. PSC-2021-0446-S-EI, the recovery of storm costs from customers will begin, on an interim basis, 60 days after the filing of a cost recovery petition and tariff with the Commission.¹ FPL has requested a 12-month recovery period, applied to all bills from January 1, 2025, through December 31, 2025.

We have jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

DECISION

Interim storm restoration recovery charge

As stated above, FPL filed a petition for a limited proceeding seeking authority to implement an interim storm restoration charge to recover an estimated total of \$1.2 billion for incremental storm restoration costs for the Storms and to replenish its storm reserve. In its petition, FPL requested to replenish the storm reserve to \$150 million.

¹ Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power and Light Company*.

ORDER NO. PSC-2024-0503-PCO-EI
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PAGE 2

The petition was filed pursuant to the provisions of the 2021 Settlement approved by us in Order Nos. PSC-2021-0446-S-EI and PSC-2021-0446A-S-EI. Pursuant to paragraph 10 of the 2021 Settlement, FPL can begin recovery of storm costs 60 days following the filing of a petition for recovery.

In its petition, FPL stated that it had incurred approximate recoverable costs in the amount of \$113.5 million for Hurricane Debby, \$157.8 million for Hurricane Helene, and \$811.1 million for Hurricane Milton. The Company further stated that all amounts were calculated in accordance with the Incremental Cost and Capitalization Approach methodology prescribed in Rule 25-6.0143, Florida Administrative Code.

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, will be considered by us at a later date.

Based on a review of the information provided by FPL in its petition, we hereby authorize the Company to implement an interim storm restoration recovery charge subject to refund. Once the total actual storm costs are known, FPL shall be required to file documentation of the storm costs for our review and true-up of any excess or shortfall.

Corporate undertaking

We find that all funds collected shall be subject to refund shall be secured by a corporate undertaking. The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. FPL requested a 12-month collection period from January 2025 through December 2025 for the Interim Storm Recovery charges of approximately \$1.2 billion related to the Storms. We reviewed FPL's three most recent annual reports filed with this Commission (2023, 2022, and 2021) to determine if the Company can support a corporate undertaking to guarantee the funds collected for recovery of incremental storm restoration costs related to all the weather events. FPL's financial information demonstrates the Company has acceptable levels of liquidity, ownership equity, profitability, and interest coverage to support a potential refund of \$1.2 billion. Moreover, it is improbable FPL will be required to refund the entire requested amount.

FPL has adequate resources to support a corporate undertaking in the amount requested. Based on our analysis, we find that a corporate undertaking of \$1.2 billion is acceptable. This brief financial analysis is only appropriate for deciding if the Company can support a corporate undertaking in the amount proposed and should not be considered a finding regarding our position on other issues in this proceeding.

Interim storm restoration recovery charge

FPL calculated the interim storm surcharge for the 12-month period of January 1, 2025 through December 31, 2025, subject to true-up once the final total recoverable storm amount is known and determined. FPL states that the updated surcharges are allocated to the rate classes consistent with the rate design approved in the 2021 Settlement. We have reviewed the allocation to rate classes and find that the allocations provided in Appendix F to FPL's petition

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are consistent with those approved in FPL's most recent rate case. Furthermore, we have reviewed the derivation of the surcharges provided in Appendix F to the petition and find that the surcharges have been calculated correctly, using projected kilowatt hour (kWh) sales for January through December 2025.

The proposed interim storm restoration surcharges are shown on Fifth Revised Tariff Sheet No. 8.030.7, provided in Appendix G to FPL's petition. For residential customers, the proposed surcharge would be 1.202 cents per kWh, which equates to a total surcharge of \$12.02 for a 1,000 kWh monthly bill. The storm cost recovery surcharge would be included in the non-fuel energy charge on customer bills.

Paragraph 10(b) of the 2021 Settlement states that FPL may petition us for recovery of storm costs at a rate beyond \$4.00 on a 1,000 kWh residential bill if FPL incurs in excess of \$800 million of storm recovery costs. FPL has requested to recover \$1.2 billion in incremental storm restoration costs.

We hereby approve FPL's proposed interim storm restoration recovery tariff and associated surcharges, as shown in Attachment A to this order. The tariff shall become effective the first billing cycle of January 2025. The interim storm restoration surcharges shall be subject to final true-up once the total actual storm costs are known.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's request to implement an interim storm restoration recovery charge subject to refund is hereby granted. It is further

ORDERED that Florida Power & Light Company's interim storm restoration recovery tariff, found in Attachment A hereto, is approved effective the first billing cycle of January 2025. The interim storm restoration surcharges shall be subject to final true-up once the total actual storm costs are known. It is further

ORDERED that Florida Power & Light Company shall post a corporate undertaking in the amount of \$1.2 billion. It is further

ORDERED that this docket shall remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge, if warranted.

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By ORDER of the Florida Public Service Commission this 17th day of December, 2024.



ADAM J. TEITZMAN
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Office of Commission Clerk, in the form prescribed by Rule 25-22.0376, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

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ATTACHMENT A

FLORIDA POWER & LIGHT COMPANY

~~Fourth-Fifth~~ Revised Sheet No. 8.030.7
Cancels ~~Fourth-Third~~ Revised Sheet No. 8.030.7

(Continued from Sheet No. 8.030.3)

2025 INTERIM STORM RESTORATION RECOVERY

APPLICATION:

The 2025 Interim Storm Restoration Recovery Surcharge is designed to recover incremental storm-related costs incurred by the Company related to Hurricanes Debby, Helene, and Milton. The factor is applicable to the Energy Charge under FPL's various rate schedules.

Rate Schedule	¢/kWh
<u>ALL KWH - RS-1, RTR-1</u>	<u>1.202</u>
<u>GS-1, GST-1</u>	<u>1.118</u>
<u>GSD-1, GSD-1EV, GSDT-1, HLFT-1, SDTR-1</u>	<u>0.545</u>
<u>GSLD-1, GSLD-1EV, GSLDT-1, CS-1, CST-1, HLFT-2, SDTR-2</u>	<u>0.522</u>
<u>GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3</u>	<u>0.397</u>
<u>GSLD-3, GSLDT-3, CS-3, CST-3</u>	<u>0.024</u>
<u>OL-1</u>	<u>5.035</u>
<u>OS-2</u>	<u>1.436</u>
<u>SL-1, PL-1, LT-1, OS I/II</u>	<u>2.072</u>
<u>SL-1M</u>	<u>1.089</u>
<u>SL-2</u>	<u>0.598</u>
<u>SL-2M</u>	<u>2.800</u>
<u>SST-1(T), ISST-1(T)</u>	<u>0.021</u>
<u>SST-1(D1), SST-1(D2), SST-1(D3), ISST-1(D)</u>	<u>2.552</u>
<u>CILC-1(D)</u>	<u>0.394</u>
<u>CILC-1(G)</u>	<u>0.513</u>
<u>CILC-1(T)</u>	<u>0.024</u>
<u>MET</u>	<u>0.540</u>
<u>GSCU-1</u>	<u>2.509</u>

~~RESERVED FOR FUTURE USE~~

(Continued on Sheet No. 8.031)

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-FIN-2

SUBJECT

Permanent Rates

REQUEST

Corrections and Revisions to LUMA's Filing. As the Company discovers errors in its filing on (1) LUMA's Optimal budget on Schedule A-1, (2) LUMA's Constrained budget on Schedule A-2, (3) LUMA's financial, operational and other matters on Schedules B through H, and (4) any other relevant schedules or exhibits, please identify and explain such errors and how they are being corrected, and provide the related documentation to support any changes. Please update this response as additional information becomes available.

RESPONDER

Alejandro Figueroa

RESPONSE

In order to be efficient and to minimize third party consultant costs, LUMA will continue to update this RFI response as errors and/or omissions are discovered throughout discovery, and will update the full schedule package one time only, closer to evidentiary hearing on revenue requirement

In terms of identifying the adjustments and their impact on the proposed revenue requirement, LUMA refers PREB's consultants to *PC-of-LUMA-FIN-2_Attachment 1*. The workbook contains updates to Schedule C-2 Optimal and Schedule C-2 Constrained and shows the adjustments to the revenue requirement for each of LUMA, PREPA, and Genera for each fiscal year in the rate period. LUMA submits using C-2 is appropriate because it summarizes the revenue requirement in its entirety, any updates to the revenue requirement will be reflected in this schedule in any event.

Table 2-1, below, lists out the reconciling items that constitute the difference between the Optimal Budget revenue requirement as filed on July 3rd, and the updated revenue requirement detailed in Attachment 1.

Table 2-1. Optimal Budget – Reconciliation to July 3rd Filing

Description	FY2026 (\$)	FY2027 (\$)	FY2028 (\$)	Notes
July 3 rd Total O&M	5,295,179,867	5,466,955,847	5,581,468,402	
PREPA Placeholder	(87,760,970)	(111,127,677)	(117,367,377)	July 3 rd filing included a placeholder for PREPA.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

				This placeholder is backed out and replaced with the next two line items in this table.
PREPA Revenue Requirement	91,870,573	81,357,353	79,009,017	See PC-of-LUMA-FIN-3
PREPA Pension	307,475,422	298,658,581	298,438,608	See PC-of-LUMA-FIN-3
Genera Addition	-	1,000,000	1,000,000	See PC-of-LUMA-FIN-3
Formula error re: Genera reserve	-	30,000,000	30,000,000	LUMA's July 3 rd filing included a formula error whereby these amounts, although present on schedule C-2, was not incorporated into the total revenue requirement.
LUMA Adjustments	(150,000)	-	-	See Table 2-3, below
FOMB Advisory	18,324,982	5,866,071	9,197,272	See Table 2-3, below
LUMA Interim	8,750,000	6,562,500	4,375,000	See Table 2-3, below
Updated Revenue Requirement	5,633,689,875	5,779,272,674	5,886,120,921	

Table 2-2, below, lists out the reconciling items that constitute the difference between the Optimal Budget revenue requirement as filed on July 3rd, and the updated revenue requirement detailed in Attachment 1.

Table 2-2. Constrained Budget – Reconciliation to July 3rd Filing

Description	FY2026 (\$)	FY2027 (\$)	FY2028 (\$)	Notes
Starting Point: July 3 rd Revenue Requirement	4,669,025,586	4,769,520,633	4,797,128,031	
PREPA Placeholder	(78,470,749)	(79,876,521)	(83,459,839)	Reverse PREPA placeholder amounts
PREPA Revenue Requirement	91,870,573	81,357,353	79,009,017	See PC-of-LUMA-FIN-3
PREPA Pension	307,475,422	298,658,581	298,438,608	See PC-of-LUMA-FIN-3
Genera Addition	1,000,000	1,000,000	1,000,000	See PC-of-LUMA-FIN-3
LUMA Adjustments	(100,000)	(165,935)	(172,575)	See Table 2-3, below
FOMB Advisory	18,324,982	5,866,071	9,197,272	See Table 2-3, below
LUMA Interim	8,750,000	6,562,500	4,375,000	See Table 2-3, below
Updated Revenue Requirement	5,017,875,815	5,082,922,682	5,105,515,514	

Explanations for the updates made to *PC-of-LUMA-FIN-2_Attachment 1* appear in Table 2-3, below. The table effectively serves as a map to Attachment 1. The adjustments are not listed in any particular order.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Table 2-3. LUMA's Updates to Revenue Requirement

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
C-2 Reference	Line Item Reference(s)	Applicable Fiscal Year	Description	July 3 Filing Amount	Adjustment	Updated Amount	Reason for Change
<i>C-2 Optimal & C-2 Constrained</i>	42	2026	FOMB Advisor Costs	\$32,964,202	\$18,324,982	\$51,289,184	Inadvertent error in July 3rd filing. This number was provided by the FOMB. See NPFGC-of-LUMA-PROV-19 for details.
<i>C-2 Optimal & C-2 Constrained</i>	41	2026	LUMA Interim Costs	\$18,700,000	\$8,750,000	\$27,450,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed. See NPFGC-of-LUMA-PROV-19 for details.
<i>C-2 Optimal & C-2 Constrained</i>	42	2027	FOMB Advisor Costs	\$19,778,521	\$5,866,071	\$25,644,592	Inadvertent error in July 3rd filing.
<i>C-2 Optimal & C-2 Constrained</i>	41	2027	LUMA Interim Costs	\$11,150,000	\$6,562,500	\$17,712,500	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
<i>C-2 Optimal & C-2 Constrained</i>	42	2028	FOMB Advisor Costs	\$8,241,051	\$9,197,272	\$17,438,323	Inadvertent error in July 3rd filing.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
<i>C-2 Optimal & C-2 Constrained</i>	41	2028	LUMA Interim Costs	\$7,050,000	\$4,375,000	\$11,425,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
<i>C-2 Optimal & C-2 Constrained</i>	7	2026	Other Income	\$56,501,061	\$27,903,135	\$84,404,196	Inadvertent error in July 3 rd filing. <i>Other Income</i> has been standardized to the number used in the Energy Bureau's July 31 st Provisional Rate Order.
<i>C-2 Optimal & C-2 Constrained</i>	7	2027	Other Income	\$56,695,461	\$30,646,002	\$87,341,462	Inadvertent error in July 3 rd filing. This number is based on the FY2026 forecast, inflated by 3.48%.
<i>C-2 Optimal & C-2 Constrained</i>	7	2028	Other Income	\$56,370,898	\$34,010,047	\$90,380,94	Inadvertent error in July 3 rd filing. This number is based on the FY2027 forecast, inflated by 3.48%.
<i>C-2 Constrained</i>	60	FY2027	Non Federally Funded Capital	\$165,935	(\$165,935)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
<i>C-2 Constrained</i>	60	FY2028	Non Federally Funded Capital	\$172,575	(\$172,575)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
C-2 Optimal	35	FY2026	Professional & Technical Services	\$8,085,000	(\$150,000)	\$7,935,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
C-2 Constrained	35	FY2026	Professional & Technical Services	\$5,785,000	(\$100,000)	\$5,685,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Alejandro Figueroa, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Alejandro Figueroa

PC Ex. 62.07
Referenced ROIs

PC-of-LUMA-FIN-2

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-FIN-2

SUBJECT

Permanent Rates

REQUEST

Corrections and Revisions to LUMA's Filing. As the Company discovers errors in its filing on (1) LUMA's Optimal budget on Schedule A-1, (2) LUMA's Constrained budget on Schedule A-2, (3) LUMA's financial, operational and other matters on Schedules B through H, and (4) any other relevant schedules or exhibits, please identify and explain such errors and how they are being corrected, and provide the related documentation to support any changes. Please update this response as additional information becomes available.

RESPONDER

Alejandro Figueroa

RESPONSE

In order to be efficient and to minimize third party consultant costs, LUMA will continue to update this RFI response as errors and/or omissions are discovered throughout discovery, and will update the full schedule package one time only, closer to evidentiary hearing on revenue requirement

In terms of identifying the adjustments and their impact on the proposed revenue requirement, LUMA refers PREB's consultants to *PC-of-LUMA-FIN-2_Attachment 1*. The workbook contains updates to Schedule C-2 Optimal and Schedule C-2 Constrained and shows the adjustments to the revenue requirement for each of LUMA, PREPA, and Genera for each fiscal year in the rate period. LUMA submits using C-2 is appropriate because it summarizes the revenue requirement in its entirety, any updates to the revenue requirement will be reflected in this schedule in any event.

Table 2-1, below, lists out the reconciling items that constitute the difference between the Optimal Budget revenue requirement as filed on July 3rd, and the updated revenue requirement detailed in Attachment 1.

Table 2-1. Optimal Budget – Reconciliation to July 3rd Filing

Description	FY2026 (\$)	FY2027 (\$)	FY2028 (\$)	Notes
July 3rd Total O&M	5,295,179,867	5,466,955,847	5,581,468,402	
PREPA Placeholder	(87,760,970)	(111,127,677)	(117,367,377)	July 3 rd filing included a placeholder for PREPA.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

				This placeholder is backed out and replaced with the next two line items in this table.
PREPA Revenue Requirement	91,870,573	81,357,353	79,009,017	See PC-of-LUMA-FIN-3
PREPA Pension	307,475,422	298,658,581	298,438,608	See PC-of-LUMA-FIN-3
Genera Addition	-	1,000,000	1,000,000	See PC-of-LUMA-FIN-3
Formula error re: Genera reserve	-	30,000,000	30,000,000	LUMA's July 3 rd filing included a formula error whereby these amounts, although present on schedule C-2, was not incorporated into the total revenue requirement.
LUMA Adjustments	(150,000)	-	-	See Table 2-3, below
FOMB Advisory	18,324,982	5,866,071	9,197,272	See Table 2-3, below
LUMA Interim	8,750,000	6,562,500	4,375,000	See Table 2-3, below
Updated Revenue Requirement	5,633,689,875	5,779,272,674	5,886,120,921	

Table 2-2, below, lists out the reconciling items that constitute the difference between the Optimal Budget revenue requirement as filed on July 3rd, and the updated revenue requirement detailed in Attachment 1.

Table 2-2. Constrained Budget – Reconciliation to July 3rd Filing

Description	FY2026 (\$)	FY2027 (\$)	FY2028 (\$)	Notes
Starting Point: July 3 rd Revenue Requirement	4,669,025,586	4,769,520,633	4,797,128,031	
PREPA Placeholder	(78,470,749)	(79,876,521)	(83,459,839)	Reverse PREPA placeholder amounts
PREPA Revenue Requirement	91,870,573	81,357,353	79,009,017	See PC-of-LUMA-FIN-3
PREPA Pension	307,475,422	298,658,581	298,438,608	See PC-of-LUMA-FIN-3
Genera Addition	1,000,000	1,000,000	1,000,000	See PC-of-LUMA-FIN-3
LUMA Adjustments	(100,000)	(165,935)	(172,575)	See Table 2-3, below
FOMB Advisory	18,324,982	5,866,071	9,197,272	See Table 2-3, below
LUMA Interim	8,750,000	6,562,500	4,375,000	See Table 2-3, below
Updated Revenue Requirement	5,017,875,815	5,082,922,682	5,105,515,514	

Explanations for the updates made to *PC-of-LUMA-FIN-2_Attachment 1* appear in Table 2-3, below. The table effectively serves as a map to Attachment 1. The adjustments are not listed in any particular order.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Table 2-3. LUMA's Updates to Revenue Requirement

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
C-2 Reference	Line Item Reference(s)	Applicable Fiscal Year	Description	July 3 Filing Amount	Adjustment	Updated Amount	Reason for Change
<i>C-2 Optimal & C-2 Constrained</i>	42	2026	FOMB Advisor Costs	\$32,964,202	\$18,324,982	\$51,289,184	Inadvertent error in July 3rd filing. This number was provided by the FOMB. See NPFGC-of-LUMA-PROV-19 for details.
<i>C-2 Optimal & C-2 Constrained</i>	41	2026	LUMA Interim Costs	\$18,700,000	\$8,750,000	\$27,450,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed. See NPFGC-of-LUMA-PROV-19 for details.
<i>C-2 Optimal & C-2 Constrained</i>	42	2027	FOMB Advisor Costs	\$19,778,521	\$5,866,071	\$25,644,592	Inadvertent error in July 3rd filing.
<i>C-2 Optimal & C-2 Constrained</i>	41	2027	LUMA Interim Costs	\$11,150,000	\$6,562,500	\$17,712,500	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been included in and approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
<i>C-2 Optimal & C-2 Constrained</i>	42	2028	FOMB Advisor Costs	\$8,241,051	\$9,197,272	\$17,438,323	Inadvertent error in July 3rd filing.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
<i>C-2 Optimal & C-2 Constrained</i>	41	2028	LUMA Interim Costs	\$7,050,000	\$4,375,000	\$11,425,000	Inadvertent omission in July 3 rd filing. <i>LUMA Interim Costs</i> are LUMA's costs associated with supporting the Title III process. In years past these have been approved as part of the <i>PREPA Restructuring & Title III</i> line. For the July 3 rd filing, these were inadvertently missed.
<i>C-2 Optimal & C-2 Constrained</i>	7	2026	Other Income	\$56,501,061	\$27,903,135	\$84,404,196	Inadvertent error in July 3 rd filing. <i>Other Income</i> has been standardized to the number used in the Energy Bureau's July 31 st Provisional Rate Order.
<i>C-2 Optimal & C-2 Constrained</i>	7	2027	Other Income	\$56,695,461	\$30,646,002	\$87,341,462	Inadvertent error in July 3 rd filing. This number is based on the FY2026 forecast, inflated by 3.48%.
<i>C-2 Optimal & C-2 Constrained</i>	7	2028	Other Income	\$56,370,898	\$34,010,047	\$90,380,94	Inadvertent error in July 3 rd filing. This number is based on the FY2027 forecast, inflated by 3.48%.
<i>C-2 Constrained</i>	60	FY2027	Non Federally Funded Capital	\$165,935	(\$165,935)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
<i>C-2 Constrained</i>	60	FY2028	Non Federally Funded Capital	\$172,575	(\$172,575)	\$0	Inadvertent error in the Constrained Budget for PBUT4. See PC-of-LUMA-TRS-6 for details.
C-2 Optimal	35	FY2026	Professional & Technical Services	\$8,085,000	(\$150,000)	\$7,935,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
C-2 Constrained	35	FY2026	Professional & Technical Services	\$5,785,000	(\$100,000)	\$5,685,000	Inadvertent error in July 3 rd filing. See PC-of-LUMA-ACCTPAY-7 for details.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Attestation

I, Alejandro Figueroa, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Alejandro Figueroa

PC-of-LUMA-FIN-3

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-FIN-3

SUBJECT

Permanent Rates

REQUEST

Has LUMA incorporated any revisions or updates that were provided by Genera and/or PREPA to its Optimal and Constrained filing schedules (i.e., Schedules A-1 and A-2 and Schedules B through H) since the initial July 3, 2025 filing date? If so, please identify and explain all such revisions or changes made by Genera and/or PREPA and provide the related documentation to support such changes. Please update this response as additional information becomes available.

RESPONDER

Alejandro Figueroa

RESPONSE

Yes. In the days prior to submitting this response, LUMA sent a letter to PREPA, requesting that they provide any updates to the information that they submitted on June 30, 2025. PREPA counsel confirmed to LUMA counsel that at present, PREPA does not have any updates to the June 30th information aside from the update to the ERS Pension Funding Requirement as filed on July 17th.¹ PREPA's updates have been incorporated into the master revenue requirement schedules attached as *PC-of-LUMA-FIN-2_Attachment 1*. Please refer to the *Information* tab for details on how the costs were incorporated.

Similarly, in the days prior to submitting this response, LUMA sent a letter to Genera, requesting that they provide any updates to the information that was filed on their behalf by LUMA as part of the July 3, 2025 filing. Genera representatives reached out to communicate one update to LUMA representatives. Genera's update has been incorporated into *PC-of-LUMA-FIN-2_Attachment 1*. Please refer to Line 36, columns AF and AW of tab *C-2 Optimal* and Line 36, columns O, AF, and W of tab *C-2 Constrained*.

Attestation

¹ See PREPA's Responses to Hearing Examiner's Request for Information in the Agenda for the July 11 2025 conference and to Supplement Rate Case Application filed on NEPR-AP-2023-0003, July 17, 2025

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

I, Alejandro Figueroa, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Alejandro Figueroa

PC-of-Genera-FIN-4

Docket Number: NEPR-AP-2023-0003

In Re: PUERTO RICO ELECTRIC POWER AUTHORITY RATE REVIEW

Re: RESPONSES TO REQUEST OF INFORMATION PC-OF-GENERA-FIN-4

Genera submits this response without waiving any right regarding admissibility of evidence in this rate proceeding. Genera expressly reserve the right to supplement, amend, clarify, or correct this response at any time, including upon receipt of additional information or pursuant to orders from the Energy Bureau.

GPR- PC- NEPRAP20230003- PC-OF-GENERA-FIN-4

REQUEST:

Corrections and Revisions to Genera's Filing. As the Company discovers errors in its filing on (1) Genera's Optimal budget on Schedule A-1, (2) Genera's Constrained budget on Schedule A-2, (3) Genera's financial, operational and other matters on Schedules B through H, and (4) any other relevant schedules or exhibits, please identify and explain such errors and how they are being corrected, and provide the related documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE:

Genera coordinated with LUMA to inform of any corrections or revisions to its schedules as requested by the Energy Bureau. On August 28, 2025, LUMA submitted the revised schedules with Genera's input, see, ROI PC-of-LUMA-FIN-3. Genera's specific correction related to the Finance Department's line item for "Professional & Technical Outsourced Services". This correction was already

reflected in Exhibit 22.2 REV and consisted of an upward adjustment in the amount of \$1 million to ensure that the Finance Department budgets are accurately represented.

The specific adjustments are reflected as follows:

- Optimal Budget (Schedule A-1): FY2027 (cell BB50) and FY2028 (cell CN50).
- Constrained Budget (Schedule A-2): FY2026 (cell P50), FY2027 (cell BB50), and FY2028 (cell CN50).

These revisions are limited exclusively to the Finance Department's Professional & Technical Outsourced Services line item. No other schedules or budget categories were affected. The adjustment was necessary to align the filed schedules with the supporting documentation and to correct an inadvertent discrepancy.

By confirming the updated figures in its filing, LUMA has ensured that the record now reflects the corrected amounts of Genera's Schedules in accordance with the requirements of the proceeding.

Attestation

I, Maria Sanchez Bras, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Maria Sanchez Bras

PC-of-PREPA-FIN-5

ROI #PC-of-PREPA-FIN-5

Author: PREB Consultants

Category: Financial Costs

Recipient: PREPA

Due Date: Aug. 26, 2025

Corrections and Revisions to PREPA's Filing. As the Company discovers errors in its filing on (1) PREPA's Optimal budget on Schedule A-1, (2) PREPA's Constrained budget on Schedule A-2, (3) PREPA's financial, operation and other matters on Schedules B through H, and (4) any other relevant schedules or exhibits, please identify and explain such errors and how they are being corrected, and provide the related documents to support any changes. Please update this response as additional information becomes available.

Supplemental Response

Aug. 28, 2025

Response

PREPA and its financial consultants have evaluated PREPA's revenue requirement submitted by LUMA, on behalf of PREPA, on July 3, 2025 with the Energy Bureau as part of the Rate Application, as supplemented by PREPA in *PREPA's Responses to Hearing Examiner's Request for Information in the Agenda for the July 11 2025 conference and to Supplement Rate Case Application* (where PREPA submitted *PREPA Exhibit 45 07.17.25 PREPA Employee Retirement System, Forecast of Proposed Cash Transfers, July 31, 2025 through June 30, 2026*) and have determined that it is correct and requires no further amendments or updates.

In the event PREPA identifies any errors or deficiencies in the information currently submitted, it will promptly correct, update and/or supplement its submission.

Attestation

I, Gerard A. Gil Olazábal, Managing Director at Ankura and PREPA consultant, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief, and I would give the same response orally and present the same attachments if asked under oath.

/s/Gerard A. Gil Olazábal

PC-of-LUMA-PROV-34

Rate Review

Responses for Information on Provisional Rates

NEPR-AP-2023-0003

Response: PREPA-of-LUMA-PROV-34

SUBJECT

Provisional Rates

REQUEST

According to LUMA's Exhibit 1.0, Alejandro Figueroa's Direct Testimony, and Exhibits 1.05 and 1.06, LUMA is seeking to recover approximately \$209 million over a two-year period to reimburse LUMA's Operating Account for Outage Event Costs that were paid from the Operating Account rather than from the Outage Event Reserve Account. Of this amount, LUMA requested \$90 million to be recovered by the provisional rate during FY2026 (the total requested amount is \$120 million of which \$30 million is earmarked to replenish the Outage Event Reserve Account). According to LUMA's Exhibit 1.05, the \$209 million represent expenditures incurred from December 2023 to February 2025. How does LUMA reconcile its request for provisional rates with the regulatory principle prohibiting retroactive ratemaking? LUMA is essentially requesting a revenue increase for the period of December 2023 to February 2025 in the amount of \$209 million, \$90 million of which were requested to be recovered through provisional rates. How does LUMA reconcile this request with the Filed Rate Doctrine?

RESPONDER

Counsel for LUMA

RESPONSE

LUMA notes that this discovery request improperly seeks a legal opinion or a response on matters of law. Without waving future objections to discovery requests that elicit legal opinions, LUMA notes that there judicial precedent holds that under the filed-rate doctrine and rule against retroactive ratemaking a utility is prohibited "from collecting a rate other than the one filed with the relevant government agency and that agency "itself" cannot retroactively "impos[e] a rate increase for [power] already sold."¹ Other jurisdictions have stated that the purpose of the filed-rate doctrine and the rule against retroactive ratemaking serves two basic functions: "protect[ing] the public by ensuring that present consumers will not be required to pay

¹ *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 578 (1981).

RESPONSES TO JULY 17, 2025, REQUEST

Rate Review

for past deficits of the company in their future payments,” and (2) “prevent[ing] the company from employing future rates as a means of ensuring the investments of its stockholders.”²

Judicial precedent holds that “[t]he ‘filed rate doctrine’ forbids a regulated entity from charging a rate for its services other than the rate on file with the appropriate regulatory authority.” *Crumley v. Time Warner Cable, Inc.*, 556 F.3d 879, 881 (8th Cir. 2009) (citing *Ark. La. Gas Co. v. Hall*, 453 U.S. at 577). Under the Federal Power Act (“FPA”), the Federal Energy Regulatory Commission (“FERC”) “itself lacks authority to alter filed rates retroactively.” *City of Osceola v. Entergy Arkansas, Inc.*, 791 F.3d 904, 908 (8th Cir. 2015). If the FERC “finds a filed rate to be unreasonable, it only has statutory authority to impose a new rate prospectively.” *Id.* (citing *Ark. La. Gas Co. v. Hall*, 453 U.S. at 578). LUMA is not proposing a retroactive change to the rates that it charged customers in the past. LUMA has filed a provisional rate to be included in its new tariff charges to be applied prospectively. As required by the statute, LUMA filed a provisional rate to change the rates it charges its customers from the rates that are currently on file with the Puerto Rico Energy Bureau (“PREB”) to new rates to be charged after notice to customers with new tariff rates to be effective on September 1, 2025, provided that PREB approves the new rates. LUMA is not proposing to change any tariff rates that it charged customers prior to the effective date of the new provisional rates to collect the unfunded storm costs. Rather, it is seeking to recover unfunded storm costs through prospective rate increases.

Other jurisdictions have also recognized that there is a “plethora of cases from other jurisdictions permitting a utility to recover the extraordinary costs associated with an unusually severe storm indicate that the rule against retroactive ratemaking does not come into play in such instances.”³ Those jurisdictions have explained that if the filed-rate doctrine and rule against retroactive ratemaking came into play there would be perverse incentives contrary to public safety and reliability.⁴ For example, it has been held that “[t]he next time a storm of this magnitude occurs, the [utility] would have no incentive to . . . to restore service efficiently and swiftly to customers if no reimbursement for extraordinary expenses would be forthcoming.”⁵

² *Pub. Advocate v. PUC*, 718 A.2d 201, 206-207 (Me. 1998) (quoting *Narragansett Elec. Co. v. Burke*, 415 A.2d 177, 178-79 (R.I. 1980)).

³ *Narragansett Elec. Co.*, 415 A.2d, at 179-180 (citing the *plethora* of cases); see also *State ex rel. Pittman v. Miss. Pub. Ser. Comm’n.*, 520 So. 2d 1355, 1362 (Miss. 1987) (“The exception to the rule against retroactive ratemaking applies where an extraordinary event such as a severe storm causes damage to a utility resulting in great expense on repair and restoration of service to its customers.”); *Phila. Elec. Co. v. Pa. Publ. Util. Comm’n.*, 502 A.2d 722, 728 (Pa. 1985) (“An exception to this rule in the case of retroactive recovery of unanticipated expenses has been recognized where the expenses are extraordinary and nonrecurring”) (citing *Blue Mountain Consol. Water Co. v. Pa. Pub. Util. Comm’n.*, 57 Pa. Commonwealth Ct. 363, 426 A.2d 724 (1981); *UGI, Corp. v. Pa. Pub. Util. Comm’n.*, 49 Pa. Commonwealth Ct. 69, 410 A.2d 923 (1980)); *Re United Illuminating Co.*, 7 P.U.R. 4th 417 (Conn. P.U.C. 1974) (“The rule [against retroactive ratemaking] serves to protect present customers from paying for a utility’s past operating deficits. This aspect of the rule must be weighed against the interest of providing immediate service to customers when a destructive, unexpected storm occurs. On such an occasion the public interest in quickly restoring heat and electricity to the homes of customers must prevail.”).

⁴ *Narragansett Elec. Co.*, 415 A.2d, at 179 (stating the “application of the rule [against retroactive ratemaking] to expenses related to such an emergency situation so inextricably related to the public health and safety would serve to thwart the goal of effective customer service.”).

⁵ *Id.*

RESPONSES TO JULY 17, 2025, REQUEST

Rate Review

In addition, it has been held the filed-rate doctrine and the rule against retroactive ratemaking are not implicated when a rate adjustment “was not used to insure or improve the return of investors in the utility.”⁶

LUMA is requesting to recover extraordinary costs that it incurred to restore service to Puerto Rico following severe storm events. As an agent for a municipal utility, none of the costs that LUMA recovers are used to insure or improve the return of investors. Therefore, the filed-rate doctrine and the rule against retroactive ratemaking are not implicated here.

⁶ *Pub. Advocate*, 718 A.2d, at 206-07.

PC-of-LUMA-PROV-38

Rate Review**Responses for Information on Provisional Rates****NEPR-AP-2023-0003****Response: PC-of-LUMA-PROV-38****SUBJECT**

Provisional Rates

REQUEST

Refer to the Excel file:

LUMA Ex. 1.06 (7.03.25) - Working Papers_Provisional Rate Revenue Requirement

Refer to the following line items (amounts in \$000):

9 Bad Debt, Schedule C-2 Constrained, Row 51 of \$129,957

14 Total Provisional Revenue Requirement of \$2,419,989

Less: Projected Revenues at Present Rates, Schedule B-1 Constrained, Row 17 of -\$1,179,202

Deficiency to be Funded by Provisional Rates of \$1,184,285

Please confirm that the Bad Debt amount that LUMA has proposed for Provisional Rates of \$129,957 is 11.02% of the Projected Revenue at Present Rates of \$1,179,202. If this cannot be confirmed, explain fully and provide calculations.

What is the relationship of the Bad Debt amount and the amount of Projected Revenues at LUMA's proposed Provisional Rates?

RESPONDER

Sam Shannon

RESPONSE

For the reasons stated below, I am unable to confirm that the Bad Debt amount proposed by LUMA for Provisional rates of \$129,957 should be compared to the Projected Revenue at Present Rates of \$1,179,202.

The comparison outlined in this ROI is based upon incorrect assumptions. First, the deficiency to be collected from customers via the provisional rate rider is the difference between the revenues at present rates and the provisional revenue requirement. The proper formula for determining the bad debt

RESPONSES TO JULY 17, 2025, REQUEST

Rate Review

percentage of the total projected revenue would use the proposed permanent revenue requirement as the denominator. Therefore, the correct calculation must be done applying the bad debt percentage established in the January 10, 2017 Rate Case (2.97%)¹ to the total projected revenue.

Second, the provisional revenue requirement allows the utility to begin collecting some portion of its proposed permanent revenue requirement while the Energy Bureau considers the general revenue requirement. Provisional rates exist because, in some cases, such as this one, the test year overlaps with the period of consideration by the Energy Bureau. Because the provisional revenue requirement is only a portion of the eventual permanent revenue requirement, the evaluation of any component of the provisional revenue requirement should be based on its relation to and inclusion within the permanent revenue requirement.

Attestation

I, Sam Shannon, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Sam Shannon

¹ Final Resolution and Order entered in case no. CEPR-AP-2015-0001, *In Re: Puerto Rico Electric Power Authority Rate Review*, 6. Bad debt expense. P. 50 ("Directive. The revenue requirement for bad debt expense shall be \$97.384 million, resulting from multiplying PREPA's estimated uncollectibles rate of 2.97% by the full amount of PREPA's proposed expenses (as adjusted by the [Energy Bureau]). <https://energia.pr.gov/wp-content/uploads/sites/7/2017/01/Final-Resolution-and-Order.pdf>,

PC-of-LUMA-PROV-39

Rate Review

Responses for Information on Provisional Rates

NEPR-AP-2023-0003

Response: PC-of-LUMA-PROV-39

SUBJECT

Provisional Rates

REQUEST

Refer to Excel file:

LUMA Revenue Requirement Schedules (7.03.25)

At Schedule C-2 Constrained, Row 51 for Bad Debt which shows the \$129,957 amount (in \$000) for Bad Debt for FY 2026.

- a) What are the comparable amounts of recorded Bad Debt expense for each fiscal year, FY 2024 and FY 2025?
- b) What has LUMA done in each fiscal year, FY 2024 and FY 2025 and to-date in FY 2026 to improve collections and reduce bad debts.
- c) What else does LUMA intend to do in FY 2026 to improve collections and reduce Bad Debt.
- d) On Schedule C-2 Constrained, Row 51 for Bad Debt, the FY 2026 amount of \$129,957 (in \$000) is a typed in value amount with no supporting calculations. Identify and provide the supporting calculations in Excel. Alternatively, indicate where the supporting calculations for the FY 2026 Bad Debt amount can be found in the Excel files that were provided with LUMA's filing.
- e) Since the July 3, 2025 filing, has there been any update or revision to the FY 2026 amount of \$129,957 (in \$000) for Bad Debt? If so, identify, quantify and explain the revisions.
- f) Which components of the total annual revenue are subject to not being collected, i.e., are subject to ending up being recorded as Bad Debt or Uncollectibles Expense?
- g) Provide an analysis of the aged accounts receivable balances as of 6/30/2025.
- h) Was an analysis of the aged accounts receivable balances as of 6/30/2025, or as of any other date, used by LUMA to develop the projected FY 2026 amount for Bad Debt? If not, explain fully why not. If so, please identify and provide the analysis conducted by LUMA of aged accounts receivable and explain how that resulted in LUMA's proposed FY 2026 amount for Bad Debt in LUMA's proposed Provisional Rates Revenue Requirement.

RESPONDER

Alejandro Figueroa

RESPONSES TO JULY 17, 2025, REQUEST

Rate Review

RESPONSE

a) Historical bad debt forecasts can be referenced in previous Annual Budget Filings under Docket No. NEPR-MI-2021-0004.¹ In the FY2024 Budget the Energy Bureau approved \$59,450,000 for Bad Debts.² In the FY2025 Budget the Energy Bureau approved \$59,529,000 for Bad Debts.³

b-c) To effectively manage Accounts Receivable, LUMA has formed a specialized “Revenue Protection” team dedicated to collecting overdue debts and ensuring a focused effort, from the outset, to mitigate the accumulation of past-due accounts. LUMA’s Revenue Protection team plays a crucial role in overseeing collections, identifying delinquent accounts, enforcing credit policies, and managing bankruptcy cases. The team is committed to ensuring fair treatment for customers experiencing financial difficulties while safeguarding LUMA’s financial health, which is essential for LUMA to be able to safely and provide reliable service. LUMA has implemented a standardized 30/60/90-day collection process that involves proactive customer outreach via phone, email, and letters to facilitate payment plans for outstanding balances.

LUMA is enhancing its Customer Care and Billing System (CC&B) to automate the identification of accounts requiring collection actions during daily billing cycles, promoting consistent and efficient collection practices across various customer segments. Additionally, LUMA is nearing the completion of a Request for Proposal (RFP) to source vendor support for an initiative designed to improve digital processing capabilities, which will enhance vendor management and expand payment options for customers, thereby facilitating smoother payment transactions and improving revenue recovery. With these planned enhancements, LUMA will be able to accept payments at over 900 locations throughout the island.

d-f) To calculate bad debt expense, LUMA has used the 2.97% figure established in the Puerto Rico Electric Power Authority (PREPA) 2017 Rate Order, as discussed in *LUMA Ex. 1.0* Alejandro Figueroa’s Testimony. The calculation of Bad Debt should be the total revenue requirement (Schedule B-1 Optimal, Line No. 14), less Bad Debt Expense (Schedule B-1 Optimal, Line No. 9) multiplied by 2.97%. Given that, as described herein and in PC-of-LUMA-PROV-38, Bad Debt is a function of the total revenue requirement, LUMA respectfully requests the Energy Bureau approve the Bad Debt amount that is included in the provisional rate workpapers LUMA Ex. 1.06 (7.22.25) – Working Papers_Provisional Rate Revenue Requirement.⁴ The February 12th Resolution and Order recognized that “LUMA’s rebuttal, which will file last, might make changes to its original filing in response to comments by intervenors and the Energy Bureau’s consultants.”⁵

¹ In Re: LUMA Initial Budgets and Related Terms of Service, Docket No. NEPR-MI-2021-0004.

² See NEPR-MI-2021-0004, Determination on the FY24 Annual Budgets for the electric utility system – LUMA, Genera, and PREPA, Attachment B, FY2024 Electric Utility Annual Budgets Summary. Available at <https://energias.pr.gov/wp-content/uploads/sites/7/2023/06/20230625-MI20210004-Resolution-and-Order.pdf>

³ See NEPR-MI-2021-0004, Determination on the FY25 Annual Budgets for the electric utility, Attachment A, FY2025 Electric Utility Annual Budgets Summary. Available at <https://energias.pr.gov/wp-content/uploads/sites/7/2024/06/20240626-MI20210004-Resolution-and-Order.pdf>

⁴ Amended version submitted with PC-of-LUMA_PROV-35.

⁵ See NEPR-AP-2023-0003, Order Establishing Scope and Procedures for Rate Case, p. 4. Available at <https://energias.pr.gov/wp-content/uploads/sites/7/2025/02/20250212-AP20230003-Resolution-and-Order.pdf>

RESPONSES TO JULY 17, 2025, REQUEST

Rate Review

Based on the foregoing, and since the July 3, 2025, filing⁶ there have been no updates or revisions to LUMA's FY 2026 amount of \$129,957 (in \$000) for bad debt.

- g) Please refer to *PC-of-LUMA-PROV-39_Attachment 1* for an aging of Accounts Receivable by customer class in total and outstanding for (a) 0-30 days, (b) 30-60 days, (c) 60-90 days, and beyond (d) 90-120 days, (e) 120 days to 365 days and (f) beyond 365 as at May 31, 2025 and June 30, 2025. The data provided in ROI-LUMA-AP-2023-0003-20250324-PREB-072_Attachment 1 that was submitted as part of the July 3rd filing contained an error. Please refer to *PC-of-LUMA-PROV-39_Attachment 1* for the correct information.
- h) No analysis was conducted. Please refer to responses to d) and f) above.

Attestation

I, Alejandro Figueroa, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Alejandro Figueroa

⁶ LUMA's Motion Submitting Rate Review Petition of July 3, 2025, Docket No. NEPR-AP-2023-0003.

May 2025						
Rev. Class	0 - 30 days	30 - 60 days	60 - 90 days	90 - 120 days	+120 days	Overall
Agricultural Industrial	\$369,161	\$143,347	\$106,406	\$86,615	\$849,357	\$1,554,886
Commercial	\$86,873,731	\$25,606,973	\$10,962,802	\$5,899,501	\$83,301,798	\$212,644,804
Government *	\$47,201,116	\$33,540,883	\$25,492,917	\$12,963,203	\$46,473,555	\$165,671,676
Industrial	\$20,473,417	\$4,696,359	\$2,391,396	\$1,179,227	\$12,386,565	\$41,126,964
Other	\$10,894,859	\$5,892,687	\$21,463,493	\$6,415,580	\$147,679,684	\$192,346,304
Public Lighting	\$173,602	\$172,927	\$169,614	\$167,929	\$13,055,331	\$13,739,402
Residential	\$85,342,109	\$38,934,688	\$23,982,172	\$20,179,976	\$196,343,721	\$364,782,666
Overall	\$251,327,994	\$108,987,864	\$84,568,801	\$46,892,031	\$500,090,011	\$991,866,701

Jun 2025						
Rev. Class	0 - 30 days	30 - 60 days	60 - 90 days	90 - 120 days	+120 days	Overall
Agricultural Industrial	\$403,817	\$144,672	\$89,717	\$81,129	\$867,503	\$1,586,838
Commercial	\$94,471,037	\$23,062,587	\$9,760,110	\$6,371,949	\$83,929,384	\$217,595,066
Government *	\$52,091,993	\$30,186,601	\$23,840,897	\$12,950,164	\$43,937,182	\$163,006,837
Industrial	\$21,001,317	\$3,271,316	\$2,015,587	\$749,311	\$19,524,060	\$46,561,591
Other	\$11,043,962	\$6,374,371	\$3,781,010	\$3,113,414	\$152,407,134	\$176,719,892
Public Lighting	\$173,353	\$170,796	\$167,825	\$169,448	\$13,214,102	\$13,895,525
Residential	\$101,553,707	\$36,273,330	\$24,562,924	\$18,240,386	\$198,315,031	\$378,945,378
Overall	\$280,739,185	\$99,483,672	\$64,218,071	\$41,675,801	\$512,194,397	\$998,311,127

* Excl. CELI/ Public Lighting Gov. accounts

Response_1753220773226_PC-of-LUMA-PROV-39_PC-of-LUMA-PROV-39_Attachment 1

May 2025						
<i>Rev. Class</i>	<i>0 - 30 days</i>	<i>30 - 60 days</i>	<i>60 - 90 days</i>	<i>90 - 120 days</i>	<i>+120 days</i>	<i>Overall</i>
Agricultural Industrial	\$369,161	\$143,347	\$106,406	\$86,615	\$849,357	\$1,554,886
Commercial	\$86,873,731	\$25,606,973	\$10,962,802	\$5,899,501	\$83,301,798	\$212,644,804
Government *	\$47,201,116	\$33,540,883	\$25,492,917	\$12,963,203	\$46,473,555	\$165,671,676
Industrial	\$20,473,417	\$4,696,359	\$2,391,396	\$1,179,227	\$12,386,565	\$41,126,964
Other	\$10,894,859	\$5,892,687	\$21,463,493	\$6,415,580	\$147,679,684	\$192,346,304
Public Lighting	\$173,602	\$172,927	\$169,614	\$167,929	\$13,055,331	\$13,739,402
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Overall	\$251,327,994	\$108,987,864	\$84,568,801	\$46,892,031	\$500,090,011	\$991,866,701

Jun 2025						
<i>Rev. Class</i>	<i>0 - 30 days</i>	<i>30 - 60 days</i>	<i>60 - 90 days</i>	<i>90 - 120 days</i>	<i>+120 days</i>	<i>Overall</i>
Agricultural Industrial	\$403,817	\$144,672	\$89,717	\$81,129	\$867,503	\$1,586,838
Commercial	\$94,471,037	\$23,062,587	\$9,760,110	\$6,371,949	\$83,929,384	\$217,595,066
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Industrial	\$21,001,317	\$3,271,316	\$2,015,587	\$749,311	\$19,524,060	\$46,561,591
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Public Lighting	\$173,353	\$170,796	\$167,825	\$169,448	\$13,214,102	\$13,895,525
Residential	\$101,553,707	\$36,273,330	\$24,562,924	\$18,240,386	\$198,315,031	\$378,945,378
Overall	\$280,739,185	\$99,483,672	\$64,218,071	\$41,675,801	\$512,194,397	\$998,311,127

* Excl. CELI/ Public Lighting Gov. accounts

OIPC-of-LUMA-
NONPHYS_OPS-56

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: OIPC-of-LUMA-NONPHYS_OPS-56

SUBJECT

Permanent Rates – Non-Physical Operations

REQUEST

Request of Information – Bad Debt

Provide for each fiscal year from FY2021 through FY2025:

1. The total actual uncollectible balances recorded (in dollars) by customer class and in total.
2. The total actual revenues for each year.
3. The resulting bad debt percentage for each year, calculated as the ratio of actual uncollectible balances to total actual revenues.
4. Identify any changes in accounting policies or definitions of “bad debt” during this period that may affect comparability across years.
5. Provide a reconciliation, by fiscal year, comparing:
 - a. The bad debt amounts approved by the Energy Bureau in each Annual Budget.
 - b. The amounts budgeted by LUMA.
 - c. The actual uncollectible amounts recorded.
 - d. Any variances between approved, budgeted, and actual amounts, with explanations for significant differences.

RESPONDER

Andrew Smith

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

1. Please refer to the response to *OIPC-of-LUMA-NONPHYS_OPS-55*. Due to system limitations the total by class would require extensive work that would take a considerable amount of time. When done in response to ROI-LUMA-AP-2023-0003-20250324-PREB-72 this took ~4 weeks to produce for just that snapshot in time. For the total aggregate balance please refer to *OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1*.
2. Please refer to *OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1*.
3. Please refer to *OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1*.
4. Please refer to the response to *OIPC-of-LUMA-NONPHYS_OPS-55*.
5. a-c. Please refer to *OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1*.

d. Variance explanations between approved, budget, and actuals are provided as follows.

FY2021 – LUMA submits that variances would need to be explained by the Puerto Rico Electric Power Authority (PREPA) management as these numbers were prepared by PREPA.

FY2022 – The main variance is driven by audited adjustments prepared by PREPA's management. Bad debt records by LUMA are aligned with the budget approved by the Energy Bureau.

FY2023 – The current variance is minimal. However, LUMA notes the audit remains ongoing and most likely this number will change.

FY2024 and FY2025 – LUMA, as transmission and distribution (T&D) Operator, recorded approximately \$60 million of Bad Debt expense in FY2024 and FY2025 with a corresponding Allowance for Doubtful Accounts.¹ This amount represents the expected bad debt related to services rendered during the fiscal period(s) and is aligned with the budget(s) approved by the Energy Bureau. Additionally, in connection with its responsibilities under the Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement (T&D OMA), LUMA began a cleanup process of the aging accounts receivable, which, on commencement, had receivables that were over 10 years outstanding and no longer collectible in accordance with Puerto Rico law.

During FY2024 and FY2025, \$77 million and \$339 million of write-offs were recorded, respectively as incremental bad debt derived from old receivables that have passed the prescriptive term(s),² or the time when the probability of collection is low to nil. All the receivables written down are attributable to legacy PREPA operations (i.e., recorded before LUMA took over responsibility of the T&D System). In accordance with applicable accounting pronouncements,

¹ See NEPR-MI-2021-0004, Determination on the FY24 Annual Budgets for the electric utility system – LUMA, Genera, and PREPA, Attachment B, Line 13 Bad Debts. Available at <https://energia.pr.gov/wp-content/uploads/sites/7/2023/06/20230625-MI20210004-Resolution-and-Order.pdf>; and NEPR-MI-2021-0004, Determination on the FY25 Annual Budgets for the electric utility, Attachment A, Line 14 Bad Debts. Available at <https://energia.pr.gov/wp-content/uploads/sites/7/2024/06/20240626-MI20210004-Resolution-and-Order.pdf>. Bad Debt amounts are based on 1.5% of total revenues.

² Prescriptive terms are provided in *OIPC-of-LUMA-NONPHYS_OPS-55*.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

these write-offs need to be recorded against the existing Allowance for Doubtful Accounts in PREPA's books, which amounted to \$954 million and \$937 million as of FY2024 and FY2025, respectively.

However, PREPA has not allowed LUMA to record the transactions (the debit is affecting PREPA Company 01 while the credit is impacting LUMA Company 03, both in the Oracle system), as evidenced by a letter sent to PREPA on August 5, 2024. While LUMA continues to perform the write-offs in Company 03 in accordance with appropriate accounting pronouncements, there will continue to be a variance in bad debt against budget until the corresponding transactions are reflected in Company 01. This failure to be allowed to record transactions between the parties, also was communicated to the FOMB in a communication sent on January 24, 2025.

Accordingly, the incremental bad debt expense is due to a missing intercompany transaction between PREPA entities and should not be construed as an incremental expense.

Attestation

I, Andrew Smith, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Andrew Smith

Response_1756259199148_OIPC-of-LUMA-NONPHYS_OPS-56_OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1

		Audited		Unaudited **		
	In million	2021 *	2022	2023	2024	2025
Request 2.	Operating revenues, net	3,197,390	4,189,802	4,531,886	4,027,652	4,309,923
	Bad debt expense	62,302	147,342	75,398	137,288	398,979
Request 3.	Bad debt as a % of revenues	2%	4% 	2%	3%	9%
Request 5a.	Bad debt approved by PREB	68,407	63,405	74,400	59,450	59,529
Request 5b.	Bad debt budgeted by LUMA	68,407	63,405	74,400	59,450	59,529
Request 5c.	Uncollectible amounts recorded	62,302	147,342	75,398	137,288	398,979
Request 5d.	Variances	(6,105)	83,937	998	77,838	339,450

* During FY21 the financial results were led and worked by PREPA until May 2021, LUMA started in June 2021.

** Note: As explained in response provided on OIPC-of-LUMA-NONPHYS_OPS-55, unaudited numbers are subject to change as part of the Financial Statements Audit.

OIPC-of-LUMA-
NONPHYS_OPS-57

Rate Review

Responses for Information on Permanent Rates

NEPR-AP-2023-0003

Response: OIPC-of-LUMA-NONPHYS_OPS-57

SUBJECT

Permanent Rates – Non-Physical Operations

REQUEST

Request of Information – Bad Debt

Regarding the 2.97% Bad Debt Factor established on 2017 Rate Order:

1. Provide any benchmarking studies, industry comparisons, or regulatory precedents relied upon to support the proposed 2.97% bad debt factor.
2. Explain why the Energy Bureau should approve a bad debt methodology that deviates from historical practice and provide all quantitative evidence supporting that the proposed factor is reasonable and necessary.

RESPONDER

Alejandro Figueroa

RESPONSE

LUMA files this discovery response without in any way implying that it considers this response could be admissible as evidence in this rate review proceeding. LUMA expressly reserves the right to supplement, clarify, revise, or correct this response.

- 1-2. LUMA respectfully submits there are no benchmarking studies or useful industry comparisons due to the necessary cleanup of accounts receivable aging (and balance sheet remediation). Bad debt should be tied to sales that are written off by the utility, but LUMA needs to go through these cleanup and remediation processes first. LUMA will eventually be able to produce an accurate, credible bad debt factor. But, in the meantime, for purposes of the present rate review, LUMA chose to rely on the 2.97% that was approved in the Puerto Rico Electric Power Authority (PREPA)'s 2017 Rate Order.¹ That is the regulatory precedent from the last time an adjudicative proceeding on rates was held. The 2.97% was based upon the ratio of uncollectibles to utility

¹ Page 50, Section III(4)(6), Bad Debt Expense of Final Resolution and Order dated January 10, 2027, Docket No. NEPR-AP-2015-0001.

RESPONSES TO PERMANENT RATE REQUEST

Rate Review

operating revenue that PREPA says it experienced in FY2016. The Puerto Rico Energy Bureau (PREB)'s then-consultants, Smith and Dady, concluded that the percentage was appropriate.²

Despite the challenges described in *OIPC-of-LUMA-NONPHYS_OPS-55* of PREPA not writing off accounts receivable, and the auditing of financial statements occurring two years after the close of the year, *OIPC-of-LUMA-NONPHYS_OPS-56_Attachment 1* shows that bad debt as a percentage of revenue is higher than the 1.5% that has been the default bad debt factor approved in LUMA's annual budgets since FY2024.

Attestation

I, Alejandro Figueroa, state that the information contained in this response is complete, true, and accurate to the best of my knowledge and belief.

/s/ Alejandro Figueroa

² *Id.*, paragraph 133.