DUKE ENERGY
FLORIDA

Matthew R. Bernier
Associate General Counsel

July 8, 2026

VIA ELECTRONIC FILING

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Petition For Limited Proceeding to Approve Large Load Tariff by Duke Energy Florida, LLC;* Docket No. 20260064-EI

Dear Mr. Teitzman:

On behalf of Duke Energy Florida, LLC ("DEF"), please find enclosed for electronic filing in the above referenced docket DEF's Rebuttal Testimony of Matthew Chatelain, Benjamin Borsch, and Steven Wishart.

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

/s/ Matthew R. Bernier

Matthew R. Bernier

MRB/mh
Enclosures

106 East College Avenue, Suite 800 ▪ Tallahassee, Florida 32301
Phone: 850.521.1428 ▪ Email: matt.bernier@duke-energy.com

CERTIFICATE OF SERVICE

Docket No. 20260064-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 8th day of July, 2026.

/s/ Matthew R. Bernier
Attorney

M. Thompson / S. Farooqi Office of General Counsel Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 MThompso@psc.state.fl.us sfarooqi@psc.state.fl.us	Walter L. Trierweiler / Charles J. Rehwinkel Octavio Simoes-Ponce / Austin A. Watrous Office of Public Counsel 111 W. Madison Street, Room 812 Tallahassee, Florida 32399 Trierweiler.walt@leg.state.fl.us Rehwinkel.charles@leg.state.fl.us ponce.octavio@leg.state.fl.us watrous.austin@leg.state.fl.us
Bradley Marshall Jordan Luebkemann Earthjustice/Florida Rising 111 S. Martin Luther King Jr. Blvd. Tallahassee, Florida 32301 bmarshall@earthjustice.org jluebkemann@earthjustice.org flcaseupdates@earthjustice.org	James W. Brew / Laura Wynn Baker Sarah B. Newman Stone Mattheis Xenopoulos & Brew, PC PCS Phosphate – White Springs 1025 Thomas Jefferson Street, NW Suite E-3400 Washington, DC 20007-5201 jbrew@smxblaw.com lwb@smxblaw.com sbn@smxblaw.com
Jon C. Moyle, Jr. / Karen A. Putnal Moyle Law Firm, P.A. FIPUG 118 North Gadsden Street Tallahassee, Florida 32301 jmoyle@moylelaw.com kputnal@moylelaw.com mqualls@moylelaw.com	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

MATTHEW CHATELAIN

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20260064-EI

JULY 8, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matthew Chatelain, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. Have your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the intervenor testimony of Karl Rábago and Ron Nelson.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. My rebuttal testimony explains that this docket is appropriately focused on approving a large load tariff framework, not setting final rates, or resolving detailed cost of service issues, and demonstrates that DEF's proposal fully complies with SB 484 by reasonably ensuring that large load customers bear their cost of service without shifting costs to existing customers. I describe how the Company's proposed LLCP and LLCA establish a comprehensive, coordinated structure of protections, including CIAC requirements, minimum bill obligations, termination provisions, and financial assurance, that work together to address cost responsibility and risk while maintaining commercially reasonable terms. I respond to intervenor testimony by clarifying that their positions rely on overly rigid interpretations of the statute, unsupported assumptions about future conditions, and an improper attempt to convert this proceeding into a rate case. Finally, I explain that DEF's proposal properly preserves the Commission's discretion to evaluate detailed cost allocation, rate design, and system impacts in a future rate proceeding based on a full evidentiary record, while ensuring that appropriate customer protections are in place today.

Q. What is your overall response to the intervenor testimonies?

A. Mr. Rábago and Mr. Nelson place too much weight on issues that are more appropriately addressed in a future customer-specific rate proceeding. This docket is not a general rate case, and the Commission is not being asked to approve final, permanent rates for a specific large load customer based on a complete customer-specific evidentiary record. Rather, DEF has filed a tariff framework that is designed to satisfy SB 484 by establishing reasonable, enforceable protections intended to ensure that qualifying large load customers bear the costs and risks associated with their service and that those costs are not shifted to the general body of ratepayers. The intervenors' recommendations would, in effect, require this limited proceeding to resolve comprehensive cost-of-service and rate-design issues before an actual qualifying customer, final load characteristics, or the full record necessary to make those determinations are available. DEF's proposal addresses the statutory requirements now while preserving the Commission's ability to evaluate detailed cost allocation, rate design, and system impacts in the appropriate future proceeding.

Q. Does DEF's filing comply with SB 484?

A. While I am not a lawyer, it is our Company's position that, yes, our filing fully complies with the new legislation. Section 3 of Senate Bill 484 creates Section 366.043, Fla Stat., requiring each public utility to file a large load tariff, for commission approval, meeting minimum tariff and service requirements that (1) reasonably ensure that each large load customer bears its own full cost of service and that such cost is not shifted to the general body of ratepayers and (2) include provisions reasonably designed to prevent a public utility from providing electric service to a customer that would otherwise qualify as a large load customer if that customer is a foreign entity. Subsection 5 lists utility industry-accepted ratemaking and other financial tool elements that the Commission may approve as part of meeting the large load tariff requirements. The House Message Summary, provided on March 11, 2026, describing the approved House Amendment – 383957, specifically notes that the final revisions to SB 484 make "the rate making and other financial tools to effectuate large load tariffs to be optional and does not provide or direct the PSC to use these in creating minimum standards."

The proposal includes coordinated cost responsibility and risk mitigation mechanisms, such as CIAC requirements, minimum bill obligations, termination provisions, and financial assurance requirements, that collectively satisfy the statute's objectives while preserving the Commission's authority to appropriately determine cost allocation and rate design in a general rate proceeding.

Q. Do you agree with Mr. Rábago's argument that DEF's GSD-1 and GSDT-1 rates cannot comply with section 366.043 F.S. because they were created before the legislation and therefore were not designed to meet that intent (p. 9)?

A. No. DEF's GSD-1 and GSDT-1 rates comply with section 366.043 F.S. when combined with the tariff provisions we filed as well as the 2024 Settlement. First, it is impossible to design a rate that will make certain all customers are protected in perpetuity absent essentially carving the new customers out completely, which would eliminate current customers from the benefits that could be realized from properly executing embedded cost ratemaking. Even if incremental costs for new customers are carved out, it would still be subject to changes over time and imperfect due to nuances between embedded and incremental costs. Second, customers are currently protected by DEF's 2024 Settlement which freezes rates through 2027, ensuring no incremental costs incurred to serve a data center will increase the cost the general body of customers pay. This protects other customers through the end of 2027. Third, since there are no current customers that fall under the new legislation, any rate design, absent a complete carve out, will be somewhat imperfect. It is noteworthy that the legislation contemplates use of cost of service methodology and does not specifically state you must carve out any new large load customers – indeed, the legislature avoided using any mandatory language in section 366.043(5) directing the Commission to utilize any particular ratemaking or financial tools, opting instead for the permissive "may." DEF's proposed tariff is consistent with the legislative requirement that the utility must reasonably ensure that each large load customer bears its own full cost of service and that such cost is not shifted to the general body of ratepayers. DEF's proposed tariffs do that by establishing rates large load customers can take service under now, while the existing settlement ensures no rate increase to existing customers, and committing that as part of our next case to set rates, or in the absence of a rate case filing, in a separate standalone filing for the approval of a new large-load specific rate to take effect on January 1, 2028, we will establish specific rates for these types of customers designed specifically to collect the full cost of providing service based on a new cost of service study.

Q. How do you respond to the testimony that the GSD-1 and GSDT-1 rates are already below parity and will be further below parity due to gradualism (p. 5, 10)?

A. Whether or not the existing rates are below or at parity is irrelevant to this proceeding, as the Commission approved those rates in DEF's 2024 Settlement. While the absence of perfect parity under any single metric does not necessarily render a rate design unreasonable, I do not agree that gradualism would necessarily cause the rates to fall further below parity. Additionally, there is no need for me to specifically rebut that assertion because DEF has clearly stated that it will only serve large load customers on those existing rates until the end of 2027, if it has any large load customers. When coupled with the overall base rate freeze agreed to in the settlement, there is simply no way for other customers to be impacted. Further, DEF does not believe the Commission's practice of gradualism applies when creating a new rate class. To the extent it may, Commission practice should not overcome the requirements in section 366.043 F.S. to reasonably ensure that each large load customer bears its own full cost of service and that such cost is not shifted to the general body of ratepayers. DEF's proposal allows for the Commission to properly evaluate and rule on this issue in a future rate proceeding.

Q. Both Mr. Rábago (p. 10) and Mr. Nelson argue that the new statute requires the direct assignment of incremental costs, rather than any other allocation methodology. Do you agree?

A. No. If the statute intended for all costs to be segregated and specific rates designed based on that, it would not have said cost of service methodologies and utility industry-accepted ratemaking could be used (Section 366.043 (3)(a) and (5) F.S.). It would have simply prescribed exactly how this was to be done. DEF believes the law gives the FPSC the ability to review specific facts and determine if a proposal meets the intent. SB 484 does not require the direct assignment of all incremental or "but for" costs to large load customers, rather it explicitly points to "full cost of service" (Section 366.043 (3)(a) F.S.). The proposed LLCP and LLCA tariffs are consistent with the statutory language because they set protections that ensure that large load customers bear appropriate costs while preserving the Commission's discretion to determine how those costs should be allocated and recovered within its established ratemaking framework. Future rate cases will provide an appropriate forum in which to ensure that all customers pay an appropriate share of overall system costs. By contrast, intervenor proposals for a strict incremental cost methodology reflect a policy preference rather than a statutory requirement.

Q. While not a direct issue in this proceeding, what is your opinion as to the appropriate methodology for assigning costs to large load customers?

A. Appropriate cost allocation is a crucial component of ensuring just and reasonable outcomes for current and future customers. As background, cost allocation is a regular part of the ratemaking process, and the cost allocation methodology is reviewed and approved by the Commission in each base rate case. Cost of service studies, which guide the cost allocation process, follow well-established principles of cost causation and ensure that each customer pays an amount that is reflective of that portion of the total system costs that are driven by each customer (as assessed on a class basis).

DEF believes that the present cost of service study approach allocates costs to various customer classes for the system as a whole in a reasonable manner consistent with well-established and tested methodologies, is appropriate, and leads to a just and reasonable outcome. Indeed, while adding load to the system may create the need for additional investments to serve that load, such load additions will be factored into the cost of service study process and costs will be recovered from those customers commensurate with the load additions.

This well-established approach to cost allocation is centered on the reality that all customers are served by the entire system. It would be inconsistent with DEF's cost allocation approach to assign the cost of particular new incremental generation to particular new large load customers premised on the assumption that a particular customer is being served by a specific resource. It would also raise a number of challenging conceptual questions, including determining which new customers are served by which incremental resources and assessing how such "assignment" impacts cost responsibility for that resource and future resource additions.

DEF will evaluate the rates and revenues that result from future cost of service studies and will include appropriate rate design tools that ensure a large load customer covers its full cost of service, as is stated clearly in Part 13.08 that the new large load rate schedule will be designed to comply with the requirements of the statute. This evaluation and any proposed rate design components will be presented in future rate proceedings for Commission review and approval and will afford intervenors the opportunity to examine the impacts with all of the relevant details at that time.

Q. How do you respond to Mr. Rábago's extensive hypothetical on pages 10-12?

A. Mr. Rábago's hypothetical does not show that DEF's proposal is deficient. The statute requires utilities to file large load tariffs for Commission approval by October 1, 2026, even where, as here, the utility does not yet have an actual qualifying large load customer with final load characteristics, timing, location, and service requirements. As a result, DEF necessarily must develop a tariff framework before the Company has the customer-specific information that would be required to perform the type of detailed incremental analysis Mr. Rábago describes. His hypothetical also does not fully account for timing. As Mr. Borsch explains, DEF does not expect to be able to serve a new large load customer greater than 50 MW before DEF next sets base rates. That timing is important because the next rate case will provide the updated cost-of-service study and full evidentiary record needed to establish a specific large load rate schedule.

Mr. Rábago's hypothetical relies on a series of assumed facts to suggest that existing rates might not recover all costs under a future scenario, but it does not demonstrate that DEF's filed tariff framework fails to satisfy SB 484. The hypothetical assumes that DEF will continue serving large load customers under GSD-1 or GSDT-1 indefinitely and that the Commission would not address any future rate-design issues if the facts warranted a different treatment. It also gives insufficient weight to the protections in the current base rate settlement and to DEF's commitment to propose a dedicated large load rate schedule in the next rate case. The more appropriate approach is the one DEF has proposed: establish enforceable protections now and evaluate any future customer-specific rate design on a full evidentiary record when the relevant facts are known.

Q. Do you agree with Mr. Rábago's minimum bill calculation (p. 14)?

A. No. Mr. Rábago's minimum bill calculation does not include any cost for new investment that may be needed to serve new load, and it evaluates the minimum bill as if that provision were the sole mechanism for cost recovery under the LLCP and LLCA. That is not how DEF's proposal is structured. DEF has stated that it will propose a new large load rate schedule in its next rate case and that large load customers would take service under that rate once approved. In the interim, the proposed minimum bill should be evaluated as one component of a broader protective framework that also includes CIAC requirements, termination provisions, and financial assurance. Viewed in that context, the minimum bill serves its intended purpose by supporting meaningful cost recovery over the contract term without attempting to resolve all future rate design questions in this limited proceeding.

Q. How do you respond to Mr. Rábago's claim that there is no way to enforce DEF's commitment to propose a new large load rate in the future (p. 16)?

A. Mr. Rábago's concern does not provide a basis to reject DEF's proposal. DEF is a Commission-regulated utility and must comply with Commission orders. If the Commission directs DEF to propose a new large load rate schedule in its next rate case, DEF will be obligated to do so. To remove any ambiguity, DEF expressly commits to filing a new rate schedule designed to comply with the statutory requirements to take effect on January 1, 2028, and requests that the Commission memorialize that obligation in its order. That commitment provides a clear path for Commission review of the detailed cost allocation and rate design issues that are more appropriately addressed in DEF's next rate proceeding.

Q. If DEF incurs costs to serve a new large load customer between now and the end of 2027, do you agree with Mr. Rábago's claim (pp. 16-17) that it could defer those costs for recovery in the next rate case?

A. No. This testimony demonstrates a lack of understanding as to how rates are set and accounted for during base rate settlements. The Company will not be able to defer costs incurred during the settlement freeze and moreover does not expect to serve a large load customer prior to the end of the settlement freeze. If DEF does incur costs and the GSD-1 and GSDT-1 rates are not adequate to cover them during the settlement period, those costs will fall to the bottom line and be borne by DEF shareholders. To be clear, to the extent such costs are incurred and resulting in DEF falling below its authorized ROE band, it commits that it will not seek to adjust rates during the settlement period. To the extent DEF incurs costs to serve a future data center, DEF plans to account for them consistent with current practices and would include any large load customer costs in future rate proceedings where proper cost allocation is shown.

Q. Both Mr. Rábago (p. 20) and Mr. Nelson (p. 57-59) argue that DEF's proposed termination fee is too low. How do you respond?

A. I disagree that the proposed termination provision is too low. Mr. Rábago's analysis appears to assume that the actual costs incurred to provide service would exclude generation and certain non-CIAC transmission-related costs. DEF does not read the provision that way. Those costs would be included, as applicable, in the actual costs to serve the customer. In addition, the termination payment would be evaluated in the context of the new large load rate schedule once that schedule is established.

Mr. Nelson's proposed changes would impose requirements that are more rigid than necessary to satisfy the statute's objectives. His proposal assumes that all remaining costs should be recovered from the terminating customer, without adequately accounting for revenues already collected or the ongoing value of system assets. Generation and network transmission assets can retain value after one customer terminates service. As a result, a requirement to recover all such costs from the terminating customer could lead to overcollection in some circumstances. DEF's proposed termination provision explicitly recovers all actual costs from a large load customer that terminates prior to reaching full load ramp, as defined in an executed LLCA. As such, when this provision is evaluated as part of the overall tariff structure, it appropriately balances cost responsibility and customer protection without imposing an unnecessarily rigid recovery requirement.

Termination charges provide a two-fold benefit to improved system planning—first, they encourage submission of more accurate load ramps and capacity needs from prospective customers, and second, revenues from termination charges would serve to bridge the planning gap in resources between a reduction in demand from a large load customer and the realization of any planning adjustments necessary to account for such a load departure. In short, termination charges are appropriately sized to address the temporary revenue challenges associated with large load demand reductions, not sized to cover the full costs of a long-lived asset.

Q. Mr. Nelson references a North Carolina docket in his testimony (p. 29-30). Do you have any response?

A. Mr. Nelson's reference to a North Carolina proceeding does not provide a basis for modifying DEF's proposed tariff in this Florida docket. That proceeding involved a different utility, a different jurisdiction, a different evidentiary record, and a different regulatory context. The relevant question here is whether DEF's filing satisfies Florida law and provides reasonable protections under the circumstances presented in this docket. To the extent issues addressed in another jurisdiction may be relevant to future rate design or cost allocation, they can be evaluated, if appropriate, in a future DEF rate proceeding with a Florida-specific record.

Q. Mr. Rábago argues that the Commission should reject the provision that gives DEF flexibility to modify non-material terms. Do you agree?

A. No. First, I would note that Mr. Rábago's sweeping statement that DEF's protections are "illusory" and can disappear are a little dramatic. DEF has clearly stated in discovery responses that this provision was designed to give flexibility to negotiate minor changes to the LLCA language without having to file for approval. Intervenors suggest the LLCA permits material changes without Commission oversight; however, the agreement expressly defines a narrow and objective set of "material changes" limited to core provisions governing statutory compliance (including foreign entity restrictions), key definitions (such as the in-service date), minimum term, termination notice, minimum bill design, cost recovery mechanisms (including early termination payments), full CIAC funding, security requirements, and minimum billing demand. These provisions collectively establish the agreement's fundamental economic and risk-allocation framework, and any deviation would require Commission review, thereby ensuring the LLCA cannot be modified in a manner that undermines cost recovery, customer protections, or compliance with Section 366.043, F.S.

This approach was further emphasized in DEF's response to Staff Interrogatory No. 1 as follows: The intent of the LLCP is to help ensure the costs of serving a large load customer are placed on the prospective customer, whether the load comes about or not. Prospective large load customers may have different priorities on certain aspects of the LLCA than others, and this provision allows the Company to be flexible as it pertains to balancing a customer's priority regarding non-material items, while maintaining the intent of the LLCP. The policy is in no way intended to create a "special rate" for individual large load customers and the rate paid pursuant to the applicable rate schedule would not be subject to negotiation. Examples of non-material terms include, but are not limited to, changes in how the parties will be notified under the LLCA (paragraph 17), changes to how long the parties must negotiate in good faith to avoid disputes (paragraph 21), or changes to the nature of the interconnection (paragraph 3c).

Q. How do you respond to Mr. Rábago's and Mr. Nelson's arguments that the security provision does not sufficiently protect DEF's customers?

A. Mr. Rábago and Mr. Nelson evaluate DEF's security provision in isolation and advocate for a rigid, worst-case collateral requirement, such as a fixed amount equal to twenty-four months of minimum bills, designed to fully insulate the Company from all potential risk. By contrast, DEF's proposal appropriately relies on a layered framework of customer protections, including CIAC requirements, minimum bill obligations, termination provisions, and security collateral, each of which addresses a different aspect of cost recovery and risk mitigation. Within this framework, the security provision is not intended to serve as the sole mechanism for guaranteeing recovery under all scenarios, but rather to provide reasonable financial assurance that is aligned with the customer's risk profile and existing protections. Intervenor proposals would effectively require over-collateralization by disregarding prior cost recovery, customer creditworthiness, and the interaction of tariff provisions, resulting in requirements that exceed the Company's actual exposure. DEF's approach, by contrast, ensures that large load customers bear appropriate costs while maintaining commercially reasonable terms and preserving the Commission's balanced ratemaking framework.

Q. What is your understanding of Mr. Nelson's recommendations on transmission costs to serve large load customers (pp. 50-52)?

A. Mr. Nelson divides transmission costs into two buckets. The first bucket is only those costs specifically dedicated to the particular large load customer. The second type of cost includes "shared" transmission facilities and transmission network upgrades. Mr.

Nelson recommends that large load customers fully pay upfront for the first type of cost, without a refund. He recommends that the customer also pays upfront for the full cost of the second type of costs, but those costs can be refunded over a period of 15 years.

Q. Do you agree with these recommendations?

A. No. This docket is not about setting a specific rate or cost allocation treatment for costs from unknown and endless list of possible details, but rather it is about establishing the policy and agreement that would govern the treatment of large load customers. That being said, Mr. Nelson's transmission cost recommendation is based on a rigid "but-for" framework that assumes transmission investments can be isolated and directly assigned to a single large load customer. This approach treats both customer-specific facilities and broader network upgrades as if they were discrete, customer-dedicated assets, rather than components of an integrated transmission system.

DEF's approach reflects how transmission systems are actually planned and operated. Transmission investments, particularly upstream and network facilities, are developed as part of an integrated grid to meet overall system needs, provide reliability, and serve multiple customers over time. As such, these assets are appropriately considered within the utility's broader planning and ratemaking framework.

At the same time, DEF's proposal ensures that large load customers bear appropriate costs in the near term through CIAC requirements, minimum bill obligations, termination provisions, and related contractual protections. These mechanisms provide meaningful cost responsibility without requiring the Commission to adopt a rigid, customer-specific allocation model that does not reflect system realities.

To the extent additional or alternative transmission cost recovery mechanisms may be warranted in the future, those issues are more appropriately addressed in a future rate proceeding with a full evidentiary record. DEF's proposal preserves that flexibility while providing current customer protections and addressing the statutory requirements applicable to this tariff filing.

Q. Mr. Nelson recommends that the Commission require DEF to allocate incremental generation to large load customers. Do you agree?

A. No. This docket is about establishing the policy and agreement that would govern the treatment of large load customers, not assigning specific future generation resources to unidentified customers. Mr. Nelson's incremental generation recommendation rests on a rigid "but-for" construct that presumes new generation can be singularly identified, dedicated to, and fully recovered from an individual large load customer through a standalone charge with ongoing true-up. In my view, that premise is inconsistent with how generation is planned, financed, and regulated. Generation resources are developed through an integrated resource planning process to meet system-wide demand, maintain reliability reserves, and optimize portfolios over time, not to serve a single customer in isolation.

DEF's approach reflects these system realities while still ensuring robust customer protection. In the near term, DEF's framework, through CIAC, minimum bill obligations, termination provisions, and financial assurance, requires large load customers to bear the costs they drive and mitigates risk to existing customers. In the long term, future Ten-Year Site Plan (TYSP) filings will consider the resources needed to serve present and future customers in a least-cost manner, while future rate proceedings will provide an appropriate forum in which full cost of service, load diversity, timing of investments, and system benefits can be assessed on a complete evidentiary record to ensure that all customers pay an appropriate share of overall system costs. To the extent that future large load customers are assigned greater shares of generation costs through DEF's cost of service study, DEF's future large load rate schedule will be designed to reasonably ensure that large load customers bear their full cost of service.

By contrast, Mr. Nelson's proposal could over-assign costs by ignoring the shared and evolving benefits of generation assets, while introducing a true-up mechanism that would depart from stable retail rate design. I do not see anything in section 366.043 F.S. that requires such a prescriptive approach. To the extent the Commission determines in the future that additional tools may be warranted to address generation costs for large load customers, such as a dedicated rate class or alternative recovery mechanisms, those determinations are more appropriately made in a future rate proceeding.

For these reasons, DEF's proposal provides customer protections in this docket while preserving the Commission's flexibility to consider tailored, evidence-based rate design solutions as facts develop.

II. <u>CONCLUSION</u>

Q. Did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. My silence on any particular assertion should not be read as agreement with or consent to that assertion.

Q. Should the Commission approve the Company's tariff as filed?

A. Yes. In my view, DEF's proposed tariff should be approved because it establishes a reasonable and enforceable framework for large load service and provides meaningful protections against cost shifting to existing customers. The intervenor proposals would require the Commission to resolve complex, customer-specific cost allocation and rate design issues prematurely, without an actual qualifying customer or a complete evidentiary record. DEF's proposal strikes the appropriate balance by protecting customers today, preserving commercially reasonable terms for prospective large load customers, and maintaining the Commission's full authority to evaluate detailed cost-of-service issues in DEF's next rate proceeding.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

BENJAMIN M. H. BORSCH

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20260064-EI

JULY 8, 2026

Q. Please state your name and business address.

A. My name is Benjamin M. H. Borsch. My business address is Duke Energy Florida, LLC, 299 1st Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as the Managing Director, IRP & Analytics.

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

A. I am responsible for resource planning for DEF. I am responsible for directing the resource planning process in an integrated approach in order to find the most cost-effective alternatives to meet the Company's obligation to serve its customers in

Florida. I oversee the completion of the Company's Ten-Year Site Plan ("TYSP") filed each April.

Q. Please describe your educational background and professional experience?

A. I received a Bachelor of Science and Engineering degree in Chemical Engineering from Princeton University. I joined Progress Energy in 2008 supporting the project management and construction department in the development of power plant projects. In 2009, I became Manager of Generation Resource Planning for Progress Energy Florida, and following the 2012 merger with Duke Energy Corporation, I accepted my current position. Prior to joining Progress Energy, I was employed for more than five years by Calpine Corporation where I was Manager (later Director) of Environmental Health and Safety for Calpine's Southeastern Region. In this capacity, I supported development and operations and oversaw permitting and compliance for several gas-fired power plant projects in nine states. I was also employed for more than eight years as an environmental consultant with projects including development, permitting, and compliance of power plants and transmission facilities. I am a professional engineer licensed in Florida and North Carolina.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the intervenor testimony of Karl Rábago and Ron Nelson.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. My testimony addresses a couple of significant incorrect assumptions included in the intervenor witnesses' testimonies. First, assuming DEF was to sign an LLCA with a new large load customer prior to the expiration of the current Settlement Agreement, such a customer would be in the early stages of its load ramp-up period when DEF's intended new large load rate schedule takes effect (that is January 1, 2028). Second, again assuming the execution of an LLCA with a customer with enough projected demand to require new generation, the process of building new generation takes years and could not be completed prior to the effect date of the new rate. Finally, intervenor witnesses misunderstand how an integrated utility plans for new generation and transmission assets and therefore are mistaken on what would occur if a large load customer terminated its LLCA prior to the full 20-year term.

Q. Mr. Rabago's testimony includes a hypothetical regarding the incremental cost of serving a 1 GW large load customer (p. 11). First, does DEF have any current plans to serve any large load customers before the end of 2027?

A. No. Because DEF does not have any large load customers with a signed Large Load Customer Agreement (LLCA), it has not included any load in its TYSP.

Q. Why is this relevant to the hypothetical set forth in Mr. Rabago's testimony?

A. It supports the point that it is highly unlikely and only remotely feasible that DEF could serve any new large load customer during the period of the 2024 Settlement Agreement (through the end of 2027). As Mr. Chatelain testifies, DEF will only place customers on the GSD-1 or GSDT-1 rates until the next rate proceeding, at which time a new rate schedule will be proposed. So, the focus of this proceeding should be on the likelihood that DEF will incur costs to serve a new 50 MW or greater customer in the next 18 months. We do not have any committed large-load data center customers or projects, nothing in the load forecast suggests one is imminent, and the practical realities of siting, interconnection studies, and infrastructure development all point to a longer timeline for large-scale builds. The kind of data center development that would drive new system investment is unlikely to be in service before 2028 and, if it were, it would be only at the beginning of any load phase in. While it is technically possible to serve a 55 MW customer before the expiration of the 2024 Settlement Agreement, it is impossible to begin serving a 1 GW large load customer as posited by Mr. Rabago in his hypothetical.

Q. Mr. Rabago uses estimates from other utilities to support his hypothetical (p. 11). How do you respond?

A. Comparisons to the cost of natural gas generation by JEA and the cost of FPL's transmission lines are irrelevant to this proceeding. While we agree that DEF would likely need to build a combined cycle ("CC") unit to serve a potential data center customer in excess of 1500 or more MW, the fact is that DEF does not currently have any customers ready to take such service now. Even if such a customer were to sign an

LLCA tomorrow, it would take 6-8 years to site and build such a unit. As I understand from Mr. Chatelain's testimony, we are only proposing that large load customers take service on existing rates until the expiration of DEF's current rate settlement (i.e., the end of 2027). Even if we started the CC process tomorrow, no significant costs would be incurred and certainly no assets would go into service until it was used and useful, which would be well after the end of 2027. Mr. Rabago's hypothetical is a red herring and based on facts that simply have no chance of actually materializing.

Q. What is your understanding of how generating and transmission assets built by DEF are used?

A. DEF's generation and transmission assets are planned for, and built to, serve, and benefit the system as a whole. DEF plans to identify resource needs to serve future load increases in a manner consistent with DEF's long standing practice as identified in the 2026 Ten-Year Site Plan. DEF assesses the load for each future year and the capacity available to serve it. New resources are added to meet that load and maintain reliable service. Resources are projected in the years when the need is anticipated. The expansion planning tool assesses the cost effectiveness of different options and proposes alternatives meeting the criteria with the lowest expected cost.

Q. What would DEF do if a large load customer stopped taking service before its 20-year contract term?

A. This response focuses on the Company's actions with respect to system planning. I understand that Mr. Chatelain will address the termination provisions set forth in the large load tariff. From a system planning perspective, just like DEF does with any customer who stops service, DEF will evaluate the load forecast and other system conditions at that time to determine the most efficient way to deploy the system assets. This is particularly so because the large load customer must give at least two years' notice before terminating (unlike other customers who have no such notice requirement).

The reduction in demand from a large load customer resulting from a contract termination before the end of the term could be addressed by several potential changes to the plan. Introduction of a new customer at that same location may be possible (and many of these large load customer sites have a variety of site factors that make them conducive to various types of beneficial economic development), although there could be some delay in meaningful load additions during any transition. Alternatively, the Company would update the resource plan, adapting construction or retirement dates for other generating resources, or make short-term adjustments such as the sale of excess capacity to other utilities or otherwise absorb the load change into the future resource plan. Considering the dynamic nature of the resource planning process, it is arguably even more speculative to assume the generation and transmission resources serving a large load customer will not be able to be beneficially used to serve customers than to assume that they would.

Q. Did you respond to every contention regarding the Company's proposed plan in your rebuttal?

A. No. My silence on any particular assertion should not be read as agreement with or consent to that assertion.

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: DUKE ENERGY FLORIDA, LLC'S PETITION FOR A LIMITED PROCEEDING TO APPROVE LARGE LOAD TARIFF

REBUTTAL TESTIMONY OF

STEVEN W. WISHART

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 20260064-EI

JULY 8, 2026

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven W. Wishart. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Have you previously filed direct testimony in this docket?

A. Yes.

Q. Have your employment status and job responsibilities remained the same since discussed in your previous testimony?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my rebuttal testimony is to respond to the intervenor testimony of Karl Rábago and Ron Nelson.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please summarize your testimony.

A. My rebuttal testimony addresses the recommendations of Mr. Nelson and Mr. Rábago regarding the Company's proposed Large Load Customer Policy ("LLCP") and Large Load Customer Agreement ("LLCA"). My principal conclusions are as follows:

1. Although I am not a lawyer, my interpretation of Senate Bill 484 is that it does not require utilities to adopt an incremental cost pricing methodology. Rather, the statute requires the Commission to reasonably ensure that each large load customer bears its own full cost of service while allowing the Commission flexibility in determining how that standard should be implemented.
2. Traditional embedded cost ratemaking remains an appropriate methodology for pricing large load customers. The vast majority of large load tariffs I reviewed continue to rely on embedded cost rates supplemented with contractual protections such as minimum bills, long-term contracts, customer-funded interconnection facilities, and financial security requirements.
3. I do not agree with Mr. Nelson's proposal to allocate transmission network upgrade costs using a "but for" standard. Transmission network upgrades are shared system facilities that provide benefits beyond a single customer and, in my opinion, should

continue to be recovered through embedded transmission rates rather than being directly assigned to a single triggering customer.

4. The Company's proposed treatment of transmission interconnection facilities is reasonable and consistent with industry practice. Customer-funded, refundable Contributions in Aid of Construction ("CIACs") appropriately assign the cost of customer-specific interconnection facilities while recognizing that those facilities may subsequently provide value to other customers.
5. Most large load tariffs recover generation costs through embedded rates rather than directly assigning the cost of new generating resources to individual customers. Although a small number of utilities are evaluating alternative approaches, the predominant industry practice remains embedded cost recovery.
6. The Company's proposed financial security requirements and early termination provisions appropriately protect existing customers while providing flexibility to address the unique characteristics of individual large load customers.
7. My illustrative analysis demonstrates that revenues collected under the Company's proposed GSD-1 tariff are sufficient to recover the illustrative incremental cost of serving a representative 100 MW large load customer over the term of the contract. Accordingly, I do not agree with Mr. Nelson's assertion that the Company failed to demonstrate that embedded rates can recover the incremental cost of serving large load customers.
8. For these reasons, I recommend that the Commission approve the Company's proposed Large Load Customer Policy and Large Load Customer Agreement.

II. Senate Bill 484

Q. Please summarize Florida Office of Public Counsel's ("OPC") witness Ron Nelson's testimony regarding SB 484 and as it relates to the Company's LLCP and LLCA.

A. Mr. Nelson concludes that the Company's proposed LLCP and LLCA do not comply with the requirements of SB 484 because, in his opinion, they do not reasonably ensure that large load customers bear their full cost of service without shifting costs to the general body of ratepayers. Specifically, Mr. Nelson interprets SB 484 as requiring large load customers to directly bear all connection costs, incremental transmission costs, incremental generation costs, and other infrastructure costs incurred to serve those customers.[1] Based on that interpretation, Mr. Nelson recommends that the Commission reject the Company's proposed LLCP, LLCA, and related CIAC revisions, and instead require the Company to adopt an incremental cost allocation framework, expand the scope of facilities subject to direct customer funding, establish a separate incremental generation charge, and strengthen the proposed early termination and security provisions.[2]

Q. Do you agree with Mr. Nelson's interpretation of SB 484?

A. No, I do not. As an initial matter, I am not an attorney and do not offer legal opinions regarding the interpretation of Florida statutes. Rather, I offer my perspective as an

[1] Nelson Direct Testimony at 8:12–10:17, 11:10–20, and 13:4–16:19.
[2] Nelson Direct Testimony at 5:5–7:20 and 57:1–63:23.

economist with more than two decades of experience performing cost-of-service studies and developing utility rate designs.

In my opinion, Mr. Nelson conflates the types of costs that a large load customer must ultimately bear with the ratemaking methodology used to recover those costs. SB 484 requires that a tariff "reasonably ensure that each large load customer bears its own full cost of service" and provides examples of the types of costs that are included within that cost of service, including connection costs, incremental transmission costs, incremental generation costs, and other infrastructure costs. The statute, however, does not prescribe a particular cost allocation methodology or require utilities to establish rates based on an incremental cost standard.

Had the Legislature intended to require utilities to abandon traditional embedded cost ratemaking in favor of incremental cost pricing, it would have stated so explicitly. Instead, the Legislature adopted a performance standard that the tariff must reasonably ensure that each large load customer bears its full cost of service without shifting costs to the general body of ratepayers. In my opinion, that standard can reasonably be satisfied through more than one ratemaking approach.

Moreover, the phrase "cost of service" has a well-established meaning within utility regulation. Cost-of-service studies, which are universally used to allocate costs among customer classes, are based on average embedded costs. Thus, it is entirely reasonable to interpret the statute as requiring that large load customers pay their appropriately allocated embedded cost of service, rather than receive discounted rates that shift costs to other customer classes.

In my opinion, this interpretation is also more consistent with the Legislature's intent in enacting SB 484. Rather than prescribing a specific ratemaking methodology, the statute seeks to ensure that large load customers are not provided preferential or discounted rates that shift costs to the general body of ratepayers. Requiring each large load customer to pay its full embedded cost of service is entirely consistent with that objective because it ensures that large load customers pay the same cost-based rates as other similarly situated customers.

As I discuss later in my testimony, several utilities around the country have proposed incremental pricing mechanisms that are specifically intended to produce rates below average embedded cost in order to attract new data center development. In my opinion, it is those types of discounted pricing proposals that the Legislature sought to guard against when it required that each large load customer bear its full cost of service. Duke Energy Florida has proposed no such discount. Instead, the Company proposes that large load customers pay the applicable embedded cost-based tariff rates, together with substantial contractual protections designed to ensure that they bear the costs associated with serving their load.

Q. How does Florida Rising witness Karl Rábago characterize the requirements of SB 484?

A. Mr. Rábago further contends that allowing large load customers to initially take service under the Company's existing GSD-1 and GSDT-1 tariffs cannot reasonably ensure compliance with SB 484 because those rates were established before the enactment of the statute and, in his opinion, were not designed to recover the costs associated with serving new large load customers. He also concludes that refunding Contributions in Aid of Construction ("CIAC") results in costs being shifted to other customers and therefore is inconsistent with the requirements of SB 484.[3]

Q. Do you agree that the existing GSD-1 and GSDT-1 tariffs are not appropriate for new large load customers and are not compliant with SB 484?

A. No, I do not.

Mr. Rábago's principal argument appears to be that because the GSD-1 and GSDT-1 tariffs were established before the enactment of SB 484, they cannot reasonably ensure that large load customers bear their full cost of service. I do not find that reasoning persuasive. The timing of when a rate schedule was approved has no bearing on whether the underlying rates appropriately allocate the costs of providing service.

The rates under the GSD-1 and GSDT-1 tariffs are based on a traditional embedded cost-of-service methodology, under which costs are allocated among customer classes using well-established cost allocation factors, including measures of customer demand and energy usage. These methodologies do not distinguish between "small" and "large"

[3] Rábago Direct Testimony at 8:9–13:6.

customers within a class. Rather, customers are allocated costs in proportion to the extent they utilize the utility system. Consequently, a customer with a larger demand is allocated a proportionately larger share of system costs than a customer with a smaller demand. In my opinion, there is nothing inherent in the existing GSD-1 or GSDT-1 rate designs that makes them inappropriate simply because a customer's demand exceeds 50 MW.

I also disagree with Mr. Rábago's conclusion that the Company's existing CIAC refund provisions render the GSD-1 and GSDT-1 tariffs non-compliant with SB 484. The refund of qualifying CIAC payments has long been an established component of the Company's line extension policy and is reflected in the Company's existing revenue requirement and base rates. In other words, the cost of refunding qualifying CIAC payments is already embedded in the rates paid by customers taking service under the GSD-1 and GSDT-1 tariffs. Accordingly, to the extent a large load customer receives a refund consistent with the Company's approved tariff, that customer also pays the embedded rates that were designed to recover the costs associated with those refunds.

For these reasons, I do not agree that allowing new large load customers to temporarily take service under the existing GSD-1 and GSDT-1 tariffs is inconsistent with the requirements of SB 484. As discussed previously, the Company has committed to proposing a dedicated large load rate schedule in its next general rate case, or in the absence of a rate case filing, in a separate standalone filing for the approval of a new large-load specific rate to take effect on January 1, 2028. In the interim, the existing

GSD-1 and GSDT-1 tariffs provide a reasonable mechanism for recovering the Company's embedded cost of service. In my opinion, this measured approach is both consistent with sound ratemaking principles and fully consistent with the requirements of SB 484.

<u>III.</u> <u>Incremental versus Average Embedded Costs</u>

Q. Before addressing the specific proposals of Mr. Nelson and Mr. Rábago, would you briefly explain the difference between incremental cost and average embedded cost?

A. Yes. Throughout their testimony, both Mr. Nelson and Mr. Rábago advocate for the use of an incremental cost methodology rather than the traditional embedded cost methodology used by the Company. Before addressing their specific proposals, I believe it is helpful to explain, at a high level, the relationship between these two concepts.

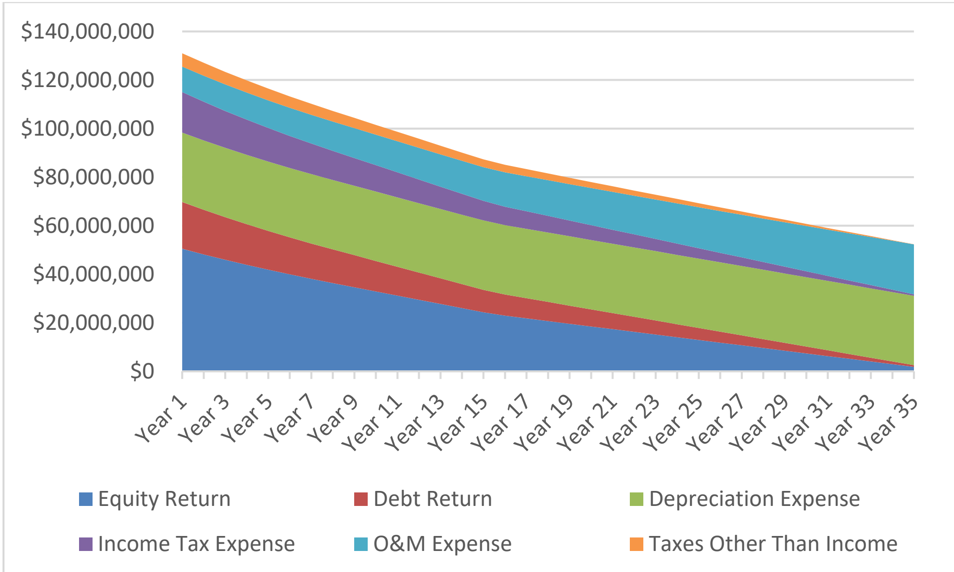
Average embedded costs represent the average cost of the utility's existing investment and operating expenses allocated among customers through a traditional cost-of-service study. As utilities continue to replace aging infrastructure, expand their systems, and invest in new generation, transmission, and distribution facilities, the embedded cost of providing service changes over time and rates generally trend higher.

Incremental costs, in contrast, represent the additional costs associated with serving a particular customer or increment of load at a specific point in time. Because incremental costs are generally associated with newly constructed facilities, they initially reflect the highest undepreciated investment in those facilities.

The important distinction is that these two measures move in opposite directions over time. The revenue requirement associated with a newly constructed utility asset declines throughout its useful life as the investment is depreciated and the required return on the remaining undepreciated investment decreases. At the same time, the utility continues to invest in new facilities needed to serve all customers, causing the average embedded cost of the overall system to tend to increase over time.

Figure SWW-1 presents the revenue requirement for a hypothetical $1 billion generating facility with a 35-year book life. As shown in the figure, the annual revenue requirement associated with that facility declines throughout its life at an average rate of approximately 2.6 percent per year as depreciation reduces the remaining investment on which the utility earns a return.

Figure SWW – 1 – 35 Year Revenue Requirements



While the cost of a newly constructed facility is highest when it first enters service, that cost declines steadily over the life of the asset. Conversely, the utility's average embedded cost of service reflects the continual addition of new infrastructure and generally increases over time. As a result, comparisons between a customer's initial incremental cost and the utility's current embedded rates provide only a snapshot at a single point in time. They do not reflect how utility costs are recovered over the multi-decade lives of utility assets. In my opinion, evaluating whether a large load customer bears its full cost of service requires consideration of this long-term relationship rather than focusing exclusively on the initial cost of newly constructed facilities.

Q. What implication does this relationship have for evaluating proposals to recover costs through an incremental pricing methodology rather than traditional embedded cost-based rates?

A. At first glance, charging a customer based on the incremental cost of the facilities constructed to serve that customer may appear to be a reasonable approach. However, utility assets remain in service for decades, and the costs associated with those assets change significantly over time.

As illustrated in Figure SWW-1, the annual revenue requirement associated with a new utility investment declines throughout the life of the asset as depreciation reduces the remaining investment on which the utility earns a return.

As a result, a customer paying embedded cost-based rates over a long-term contract will generally contribute more revenue over time than would be collected by continuing to recover only the revenue requirement associated with the original incremental facilities constructed to serve that customer. In my opinion, this demonstrates why the appropriateness of an embedded cost methodology should be evaluated over the expected life of the customer relationship rather than based solely on the facilities initially constructed when service begins.

Q. What types of incremental costs do Mr. Nelson and Mr. Rábago identify as costs that should be directly recovered from large load customers?

A. Although they differ somewhat in their specific recommendations, Mr. Nelson, and Mr. Rábago generally identify the following categories of costs as incremental costs that, in their opinion, should be directly assigned to large load customers:

- Customer connection facilities and interconnection costs.

- Incremental transmission facilities and network upgrades.
- Incremental generation facilities.
- Operations and maintenance expenses associated with serving the customer.
- Any other costs that would not have been incurred but for the addition of the large load customer.[4]

Q. What cost categories are included in traditional cost-of-service rates?

A. A traditional cost-of-service rate include all of the costs incurred by a utility to provide electric service. Major cost categories typically include:

- Production (generation) plant;
- Transmission plant;
- Distribution plant;
- Customer facilities;
- General plant;
- Production, transmission, distribution, customer, and administrative Operations and Maintenance ("O&M") expenses; and
- Administrative and General ("A&G") expenses.

The implication is that embedded cost-based service encompasses substantially more than the recovery of incremental plant investment alone. It provides for the recovery of the broad range of costs incurred by the Company to provide reliable electric service.

[4] Nelson Direct Testimony, pp. 13-16; Rábago Direct Testimony, pp. 7-12.

IV. “But For” Cost Allocation Approach

Q. Please summarize Mr. Nelson’s testimony regarding the “but for” cost allocation approach.

A. Mr. Nelson recommends expanding the application of the "but for" cost allocation principle beyond the Company's proposed CIAC provisions. He testifies that, under the "but for" standard, costs should be directly assigned to a large load customer whenever those costs would not have been incurred but for that customer's request for service. In support of this position, Mr. Nelson relies on the cost causation principles underlying FERC Order No. 2003 and recommends that the Commission apply those principles to require large load customers to bear not only the cost of customer-specific interconnection facilities, but also incremental transmission upgrades and incremental generation resources constructed to serve the customer.[5]

Q. Please summarize FERC Order 2003?

A. FERC Order No. 2003 established the Commission's standard generator interconnection procedures and agreements for the wholesale transmission system. The Order distinguished between customer-specific interconnection facilities and broader network upgrades. Interconnection facilities are paid for by the interconnecting generator because they are dedicated to that customer's project. In contrast, although an interconnecting generator may initially fund network upgrades, FERC generally

[5] Nelson Direct Testimony, pp. 19–26 and 46–56.

required the transmission provider to refund those costs through transmission service credits because network upgrades benefit the transmission system as a whole.[6]

Order No. 2003 also discussed a "but for" or participant-funding approach under which a customer pays for upgrades that would not have been constructed but for its interconnection request. However, FERC declined to adopt that approach as the general rule for non-independent transmission providers, such as DEF, concluding that determining which facilities satisfy the "but for" test is inherently subjective and could permit discriminatory cost allocation. Instead, FERC generally preserved its crediting policy.

Q. Does FERC Order No. 2003 provide persuasive precedent for applying a "but for" cost allocation methodology to retail electric service for large load customers?

A. Mr. Nelson relies on FERC Order No. 2003 as support for extending a 'but for' cost allocation methodology to DEF's retail large load tariff. However, Order No. 2003 addressed wholesale generator interconnections under the Federal Power Act, not retail electric service. Also, the order did not adopt a broad “but for” pricing rule for shared network facilities. Rather, FERC generally required transmission providers to refund the costs of network upgrades because those facilities provide system-wide benefits, while limiting permanent participant funding to certain circumstances involving independent transmission organizations.

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[6] FERC Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 104 FERC ¶61,103 (2003).

Q. Is the “but for” principle a traditional cost allocation and rate making approach?

A. No. Traditional retail utility rates are generally based on an embedded cost-of-service methodology, under which the utility's total revenue requirement is allocated among customer classes using established cost allocation principles. While the "but for" concept may be appropriate for identifying certain customer-specific facilities, it is not the traditional methodology used to allocate the broader costs of providing retail electric service.

Q. Does the integrated nature of the electric system affect your opinion?

A. Yes. Unlike customer-specific facilities, transmission and generation resources become part of an integrated system that serves all customers. Over time, additional customers may utilize those facilities, and the facilities may provide broader system reliability and operational benefits. Traditional embedded cost-of-service ratemaking recognizes these shared system benefits.

Q. Would application of a "but for" cost allocation methodology only to future large load customers result in consistent treatment among customer groups?

A. In my opinion, it would not. DEF's existing transmission and generation system was constructed over many decades to serve the load growth of prior residential, commercial, and industrial customers. Those investments were generally recovered through traditional embedded cost-of-service ratemaking. Applying a different methodology only to future large load customers would subject those customers to a fundamentally different cost recovery framework than the one applied to the customers whose load growth drove prior system investments.

Q. Please explain further.

A. Under Mr. Nelson's proposal, a new large load customer would continue to pay embedded rates that recover the costs of the Company's existing generation and transmission system, including facilities originally constructed to serve prior customer growth. At the same time, the new customer would also be required to bear the full incremental cost of new facilities constructed to serve its load. By contrast, prior customer growth was generally accommodated through investments that were incorporated into rate base and recovered through embedded rates. In my opinion, that represents inconsistent treatment of similarly situated customers over time.

Q. Based on your review of Mr. Nelson's testimony, what is your overall opinion regarding the application of the "but for" cost allocation principle to Duke Energy Florida's proposed Large Load Customer Policy?

A. In my opinion, the "but for" principle is an appropriate tool for identifying customer-specific facilities, such as dedicated interconnection facilities, that are constructed solely to serve a particular customer. The Company's proposed LLCP and LLCA do exactly this through the application of the modified extension policy that requires large load customers to make an upfront payment for 100 percent of the dedicated transmission facilities needed to serve them. However, I do not believe it is an appropriate replacement for the traditional embedded cost-of-service methodology for shared network transmission and generation. As investments become integrated into the Company's transmission and generation system, those facilities provide benefits to the electric system as a whole and ultimately serve many customers over their useful lives. Applying a broad "but for" methodology to those system investments would represent a significant departure from traditional utility ratemaking and, in my opinion, is neither required by SB 484 nor supported by FERC Order No. 2003.

V. Large Load Tariffs and Policies in Other Jurisdictions

Q. What is the purpose of this section of your testimony?

A. In this section I will address large load tariffs, studies, and policies in other states that were mentioned by Mr. Nelson.

Q. Mr. Nelson mentions the Virginia JLARC report. What is the JLARC report?

A. JLARC is the Joint Legislative Audit and Review Commission, which is the nonpartisan research and policy analysis arm of the Virginia General Assembly. In 2023, the Virginia General Assembly directed JLARC to conduct a comprehensive study of the impacts of the rapidly growing data center industry in Virginia. The resulting report evaluated a number of policy options and recommendations intended to address the challenges associated with serving large new data center loads while protecting existing customers. Because Virginia has the largest concentration of data centers in the world, the JLARC report has become one of the most comprehensive and widely referenced independent studies of the regulatory and ratemaking issues associated with data center growth.[7]

Q. What did the JLARC study conclude regarding the rates data centers pay for electricity?

A. The JLARC report concluded that data centers are currently paying their full cost of service under existing utility rate structures. Specifically, the report states that its study "found that current rates appropriately allocate costs to the classes and customers responsible for incurring them, including data center customers." The report further notes that Dominion charges data centers under the same customer class as similarly situated industrial and large commercial customers and that reviews of Dominion's rates found only minor differences between the consultant's independently developed cost allocations and those used by the utility.[8]

Q. Does Dominion base its data center rates on average embedded costs?

A. Yes.

Q. Does Mr. Nelson reference the large load tariff proposal by Wisconsin Electric?

A. Yes. Mr. Nelson cites the recently approved Wisconsin Electric Very Large Customer (VLC") and Bespoke Resources tariffs as an example of a utility moving away from traditional embedded cost recovery. He states that Wisconsin Electric proposed directly

[7] Joint Legislative Audit and Review Commission, Data Centers in Virginia, Commission Draft, p.44.
[8] Joint Legislative Audit and Review Commission, Data Centers in Virginia (Commission Draft), p. 44.

assigning generation and transmission costs to data centers to prevent cost shifting to other customers and reduce the risk of stranded assets.[9]

Q. Is it possible that Wisconsin Electric's proposal could result in less revenue from data center customers?

A. Yes. That is possible. Under Wisconsin Electric's proposal, a customer receiving service from dedicated "bespoke" generation resources pays the costs associated with those dedicated resources rather than necessarily paying the utility's standard embedded generation rates. If the dedicated resources cost less than the average embedded cost reflected in standard tariff rates, the customer's total payments could be lower than they would have been under traditional bundled service. [10]

Q. Did Mr. Nelson mention Georgia Power in his testimony?

A. Yes. Mr. Nelson cites Georgia Power as an example of a utility experiencing significant data center-driven load growth. He notes that Georgia Power substantially increased its forecast of future generation needs and filed an application to acquire approximately 9,900 MW of new generating resources to serve that anticipated demand.[11]

Q. How did Georgia Power propose to use the incremental revenues received from large load customers?

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[9] Nelson Direct Testimony, p. 38.

[10] Wisconsin Electric Power Company, *Very Large Customer – Market Pricing Tariff* (Rate Schedule VLC), Volume 19 – Electric Rates, Original Sheet No. 238 et seq., Docket No. 6630-TE-113 (effective June 1, 2026).

[11] Nelson Direct Testimony, pp. 36-37.

A. As part of a recently approved settlement, Georgia Power agreed to file its next base rate case in a manner that ensures the incremental revenues received from large load customers place downward pressure on residential customer bills. Specifically, the settlement provides that the incremental revenues from large load customers will reduce the bill of a typical residential customer using 1,000 kWh per month by at least $8.50 per month during the years 2029 through 2031. In my opinion, this illustrates that another state has recognized that large load customers can make a positive contribution toward the utility's embedded costs, thereby reducing rates for existing customers.[12]

VI. Transmission Interconnection Cost

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony I respond to Mr. Rabago and Mr. Nelson’s proposal for the treatment of interconnection costs for new large load customers. This section is focused on just network interconnection cost. I will discuss transmission network upgrades and incremental generation resources later in my testimony.

Q. Please summarize Mr. Nelson's recommendations regarding transmission interconnection costs.

A. Mr. Nelson recommends that large load customers be required to directly fund all customer-specific transmission interconnection facilities through a non-refundable CIAC. He identifies these facilities as including customer-specific transmission service

[12] *Stipulation*, Docket Nos. 56298 and 56310, ¶ 4, p. 1.

lines, dedicated substations, and other dedicated transmission and distribution facilities constructed solely to serve a large load customer. Mr. Nelson also recommends that these facilities be funded through a non-refundable CIAC regardless of any revenue test contained in the Company's existing line extension policy.[13]

Q. Please summarize Mr. Rábago's recommendations regarding transmission interconnection costs.

A. Similar to Mr. Nelson, Mr. Rábago recommends that large load customers bear the cost of customer-specific transmission interconnection facilities and other dedicated infrastructure constructed solely to provide service to the customer. He generally characterizes these as costs that would not have been incurred but for the customer's request for service and recommends that they be directly assigned to the customer rather than recovered from other ratepayers.

Q. Do you agree with Mr. Nelson's and Mr. Rábago's recommendations regarding the treatment of transmission interconnection costs?

A. I disagree with Mr. Nelson's recommendation that the CIAC for those facilities should be non-refundable. In my opinion, DEF's proposal to require the customer to advance 100 percent of the estimated interconnection costs, while allowing those costs to be refunded over time through the revenues received from that customer, is a reasonable approach. The refund mechanism appropriately recognizes that the customer is making an ongoing contribution toward the Company's embedded cost of service while also

[13] Nelson Direct Testimony, pp. 49-51.

protecting existing customers if the projected load fails to materialize. Unlike Mr. Nelson, Mr. Rábago does not appear to recommend eliminating the refund mechanism associated with the Company's proposed CIAC provisions.

Q. Have other Florida utilities adopted refundable CIAC provisions for large transmission-voltage customers?

A. Yes. Florida Power & Light's ("FPL") Large Load Contract Service ("LLCS") tariff requires customers taking service at transmission voltage to pay any applicable CIAC pursuant to FPL's General Rules and Regulations. Specifically, the LLCS tariff applies to customers taking service at 69 kV or higher through dedicated interconnecting transmission substations and requires customers to pay the applicable CIAC established under FPL's tariff.[14]

Q. How does FPL treat large interconnection projects?

A. Under Section 11.1.1(c) of FPL's General Rules and Regulations, when an applicant requires new or upgraded facilities with an estimated cost of $50 million or more at the point of delivery, the customer must advance the total estimated construction cost before construction begins. The advance is then eligible for refund through monthly bill credits based on the customer's actual base demand and base energy charges. Refunds continue until the refundable balance has been repaid or for a maximum of five years, after which any remaining balance becomes non-refundable.[15]

[14] Florida Power & Light Company, Rate Schedule LLCS-2, Original Sheet Nos. 8.953 and 8.956 (effective Jan. 1, 2026)

[15] Florida Power & Light Company, General Rules and Regulations, Section 11.1.1(c), Fourth Revised Sheet No. 6.199 (effective Jan. 1, 2026).

Q. Why is that relevant to Duke Energy Florida's proposal?

A. It demonstrates that the Florida Commission has already approved a regulatory framework under which a large transmission-voltage customer advances the cost of facilities needed to serve its load while allowing those advances to be refunded over time through revenues generated by the customer's service. In my opinion, DEF's proposal reflects the same underlying regulatory principle of protecting existing customers while permitting the customer to recover its advance if the projected load materializes.

<u>VII. Transmission Network Upgrades</u>

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony I respond to Mr. Rabago and Mr. Nelson's proposal for the treatment of transmission network upgrade costs related to new large load customers.

Q. Please summarize Mr. Nelson's recommendations regarding transmission network upgrade costs.

A. Mr. Nelson recommends that large load customers be directly assigned the cost of transmission network upgrades that are required to serve their load, even when those facilities become part of the Company's shared transmission system. He recommends applying a "but for" cost allocation methodology under which a large load customer would be responsible for transmission network upgrades that would not have been constructed but for that customer's request for service. Unlike customer-specific interconnection facilities, Mr. Nelson recommends that these shared network upgrade costs initially be funded through a refundable CIAC, with refunds based on the revenues received from the customer over time.[16]

Q. Please summarize Mr. Rábago's recommendations regarding transmission network upgrade costs?

A. Unlike Mr. Nelson, Mr. Rábago does not distinguish between customer-specific transmission interconnection facilities and shared transmission network upgrades, nor does he propose a specific methodology for allocating the various categories of transmission costs. Rather, he generally concludes that large load customers should be responsible for the incremental transmission costs associated with serving their load in order to comply with the requirements of SB 484.[17]

Q. Do you agree that shared transmission network upgrades should be directly assigned to a single large load customer?

A. No. In my opinion, shared transmission network upgrades should not be directly assigned to a single customer because they become part of the Company's integrated transmission system and provide benefits beyond the interconnecting customer. Unlike customer-specific interconnection facilities, shared transmission network upgrades may improve system reliability, increase transfer capability, accommodate future load growth, and provide operational flexibility that benefits multiple customers over time.

[16] Nelson Direct Testimony, pp. 49-52
[17] Rábago Direct Testimony, pp. 5-6, 14-18

For these reasons, I believe shared transmission network upgrades are appropriately recovered through traditional embedded transmission rates rather than being directly assigned to a single customer.

Q. Do you agree that the costs of transmission network upgrades should be allocated using a "but for" standard?

A. No. While a large load customer may ultimately trigger the need for a particular transmission network upgrade, I do not believe that customer should automatically bear the entire cost of the upgrade. Transmission network upgrades are typically the result of many years of cumulative system growth, changing reliability requirements, evolving generation patterns, and long-term transmission planning. The addition of a new large load customer may simply be the event that causes the utility to undertake an upgrade that has been approaching the need for some time. In my opinion, it is neither equitable nor consistent with traditional cost-causation principles to assign the entire cost of a shared transmission facility to the customer whose request happens to trigger the upgrade, while ignoring the many other system conditions that also contributed to the need for the investment.

Q. What other jurisdictions does Mr. Nelson reference in support of his recommendation to directly assign transmission network upgrade costs to large load customers?

A. Mr. Nelson principally relies on FERC Order No. 2003 and its discussion of participant funding and the "but for" principle as support for directly assigning transmission network upgrade costs to the customer that triggered the need for the upgrades.[18]

Q. Do you believe FERC Order No. 2003 provides persuasive support for Mr. Nelson's recommendation?

A. No. In my opinion, FERC Order No. 2003 does not provide persuasive support for applying Mr. Nelson's proposed cost allocation methodology in this proceeding.

As discussed earlier in my testimony, FERC Order No. 2003 addressed wholesale generator interconnections under the Federal Power Act, not retail electric service. Moreover, FERC did not adopt the "but for" methodology as the general rule for shared network facilities. Instead, the Commission generally required transmission providers to refund the costs of network upgrades because those facilities provide benefits to the transmission system as a whole.

Q. Is Duke Energy Florida's proposed treatment of transmission network upgrade costs consistent with the approach taken by other electric utilities?

A. Yes. Based on my review of large load tariffs and policies adopted or proposed by other electric utilities, Duke Energy Florida's approach is consistent with the prevailing industry practice. While these utilities generally require large load customers to directly fund customer-specific transmission interconnection facilities, they continue to recover

[18] Nelson Direct Testimony, pp. 19-21 .

the costs of shared transmission network upgrades through their embedded transmission rates because those facilities become part of the integrated transmission system and provide benefits to multiple customers.

For example, I reviewed the large load policies or tariffs of AEP Ohio, Dominion Energy Virginia, Evergy Kansas and Missouri, Wisconsin Electric Power Company ("WEC"), and Ameren Missouri. Although each utility's tariff differs in its specific terms and conditions, none requires a large load customer to permanently fund all shared transmission network upgrades under the type of "but for" methodology proposed by Mr. Nelson. Instead, these utilities generally distinguish between customer-specific interconnection facilities, which are directly assigned to the customer, and shared transmission network facilities, which remain part of the utility's transmission system and are recovered through transmission rates paid by all transmission customers.

In my opinion, DEF's proposal is consistent with this longstanding distinction between customer-specific facilities and shared network infrastructure.

<u>VIII.</u> <u>New Generation Resources</u>

Q. Please summarize Mr. Nelson's and Mr. Rábago's testimony regarding new generation resources associated with large load customers.?

A. Both Mr. Nelson and Mr. Rábago argue that the costs of new generation resources constructed to serve large load customers should be borne directly by those customers rather than recovered through traditional embedded rates. They contend that Senate Bill 484 requires large load customers to pay the full incremental cost of generation resources needed to serve their load and that existing general service rates are insufficient to ensure compliance with the statute. Mr. Nelson recommends that incremental generation costs be directly assigned to the large load customer and discusses mechanisms such as an Incremental Generation Charge ("IGC") or customer-funded CIAC to recover those costs. Mr. Rábago similarly recommends that the Commission require a separate large load rate class that recovers both embedded and incremental generation costs from large load customers.[19] [20]

Q. Do other electric utilities generally require large load customers to pay the incremental cost of new generation resources?

A. No. Based on my review of large load tariffs, regulatory proceedings, and state legislation from across the country, the predominant approach is to recover generation costs through traditional embedded rates rather than directly assigning the incremental cost of new generation resources to large load customers. While some utilities have proposed mechanisms to recover incremental generation costs, very few have adopted the type of direct assignment proposed by Mr. Nelson and Mr. Rábago.

Q. What examples did you identify?

A. FPL's Large Load Contract Service tariff includes an Incremental Generation Charge ("IGC") and is one example of a utility that has adopted a mechanism to recover the

[19] Nelson Direct Testimony, pp. 54–56
[20] Rábago Direct Testimony, pp. 7–12

cost of new generation resources from large load customers. However, in my opinion, FPL's approach is an outlier among the large load tariffs I reviewed.

For example, Evergy originally proposed a System Support Rider designed to recover the cost of incremental generation resources from large load customers. However, that charge was removed as part of the settlement approved by the Kansas Corporation Commission. Similarly, Arizona Public Service has proposed a methodology for allocating certain new generation costs based on customer class load growth, and Xcel Energy Minnesota has proposed evaluating whether new large loads satisfy an incremental cost test. Neither proposal directly assigns the cost of new generation resources to individual large load customers in the manner proposed by Mr. Nelson and Mr. Rábago.

Q. How are generation costs recovered under most other large load tariffs that you reviewed?

A. The majority of the large load tariffs and policies I reviewed continue to recover generation costs through traditional embedded cost-of-service rates. This includes the large load proposals adopted or proposed by AEP Ohio, Dominion Energy Virginia, Indiana Michigan Power, Consumers Energy, Santee Cooper, Ameren Missouri, and Northwestern Energy. While these tariffs contain customer protections such as minimum bills, long-term contracts, security requirements, and customer responsibility for dedicated interconnection facilities, they generally do not require customers to pay a separate charge equal to the incremental cost of new generation resources.

Q. What conclusion do you draw from your review of these other large load tariffs?

A. In my opinion, the national trend is not to directly assign the cost of new generation resources to individual large load customers. Rather, the prevailing approach is to recover generation costs through embedded cost-of-service rates while using other mechanisms, such as long-term contracts, minimum bills, security requirements, and customer-funded interconnection facilities, to protect existing customers from the financial risks associated with serving large new loads. Duke Energy Florida's proposal is consistent with that broader industry practice.

<u>IX. Security and Early Termination</u>

Q. Please summarize Mr. Nelson's and Mr. Rábago's testimony regarding the Company's proposed financial security requirements and early termination provisions.

A. Both Mr. Nelson and Mr. Rábago conclude that the Company's proposed financial security requirements and early termination provisions do not adequately protect existing customers from the risk that a large load customer could terminate service before the Company fully recovers the costs incurred to serve that customer. Mr. Nelson recommends increasing both the early termination obligation and the required financial security. Mr. Rábago similarly concludes that the proposed termination payment and security provisions are insufficient but does not offer any specific modifications to the Company's proposal.[21] [22]

[21] Nelson Direct Testimony, pp. 57-62

[22] Rábago Direct Testimony, pp. 19-21

Q. What changes does Mr. Nelson recommend to the Company's proposed early termination provisions?

A. Mr. Nelson recommends substantially increasing the Company's proposed early termination fee. Specifically, he recommends that a customer terminating service before the end of its contract term be required to pay the greater of:

- all remaining minimum monthly bill payments for the balance of the contract term; or
- the remaining undepreciated (net book) value of the incremental generation and transmission facilities that were directly assigned to the customer.

Mr. Nelson concludes that the Company's proposed termination fee of three years of minimum monthly bills, plus the net book value of facilities subject to the CIAC provisions, does not provide sufficient protection against stranded costs.

Q. Do you agree with Mr. Nelson's proposed changes to the Company's early termination provisions?

A. No. In my opinion, the Company's proposed early termination provisions provide a reasonable balance between protecting existing customers and recognizing that the Company may mitigate or avoid many of the costs associated with an early customer departure.

First, the Company's proposed termination fee is not without precedent. For example, AEP Ohio similarly requires an early termination payment equal to three years of minimum bills under certain circumstances.[23] In contrast, Mr. Nelson recommends one of the most stringent termination provisions that I reviewed, requiring a departing customer to pay all remaining minimum monthly bills for the balance of the contract term.

More importantly, I do not believe Mr. Nelson's proposal is reasonably related to the Company's potential damages resulting from an early termination. His proposal assumes that the Company will lose all revenues associated with the remaining contract term while continuing to incur all associated costs. In practice, that assumption is unlikely to hold. The generation and transmission resources that were serving the departing customer remain part of the Company's integrated electric system and can be used to serve other retail customers or to make wholesale sales. In addition, given the strong demand for large load service, particularly from data center customers, it is reasonable to expect that, in many circumstances, the Company could replace the departing customer's load with another large load customer over time.

Accordingly, I do not believe it is reasonable to require a departing customer to pay the equivalent of all remaining minimum monthly bills regardless of the Company's ability to mitigate its damages or repurpose the underlying resources.

[23] Ohio Power Company, Schedule DCT (Data Center Tariff), Terms of Contract, Original Sheet No. 223-5, filed July 11, 2025, Case No. 24-508-EL-ATA.

Q. Do you agree with Mr. Nelson's proposal to require financial security equal to 24 months of minimum monthly bills?

A. No. Although Mr. Nelson's recommendation is generally consistent with the fixed security requirements adopted or proposed by several other utilities, I continue to support the Company's proposal.

In my opinion, the Company's proposal provides a more flexible and practical approach to establishing financial security. Unlike many large load tariffs that prescribe a fixed collateral requirement for all customers, the Company's proposal allows the required security amount to reflect the specific characteristics of each large load customer, including the size of the customer's financial obligations and its creditworthiness. At the same time, the proposal establishes a minimum level of security for customers with large termination payment obligations by requiring a Security Percentage of at least 10 percent for termination fees exceeding $100 million.

I believe this approach appropriately balances the need to protect existing customers while recognizing that the financial risk presented by a highly rated Fortune 100 company may be substantially different from that presented by a customer with a weaker financial profile. In my opinion, allowing the Company to tailor the security requirement to the circumstances of each project is preferable to imposing a single fixed collateral requirement for all large load customers.

Q. Does this conclude your testimony?

A. Yes, but the fact that I have not responded to every assertion or contention raised by intervener witnesses should not be taken to mean that I agree with them.