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Speaker of the House of Representatives

June 24, 2026

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

Re: Docket No. 20260064-EI - Petition for a limited proceeding to approve large load tariff, by Duke Energy Florida, LLC

Dear Mr. Teitzman:

Please find enclosed for filing in the above referenced docket the Direct Testimony and Exhibits of Ron Nelson. This filing is being made via the Florida Public Service Commission's web-based electronic filing portal.

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Walt Trierweiler
Public Counsel

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CERTIFICATE OF SERVICE
DOCKET NO. 20260064-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 24th day of June, 2026, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for a limited proceeding to approve large load tariff by Duke Energy Florida, LLC	DOCKET NO.: 20260064-EI FILED: June 24, 2026

DIRECT TESTIMONY

OF

RON NELSON

ON BEHALF OF THE CITIZENS OF THE

STATE OF FLORIDA

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DIRECT TESTIMONY

OF

RON NELSON

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO. 20260064-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. My name is Ron Nelson. I am a Founding Partner of Current Energy Group ("CEG"). My business address is 4764 E Sunrise Drive Unit #508, Tucson, AZ 85718.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am filing testimony on behalf of the Florida Office of Public Counsel ("OPC").

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have worked with numerous consumer advocates, nongovernmental organizations, utilities, and public utility commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, distributed energy resources ("DER"), rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles. Prior to founding CEG, I briefly worked for my own sole proprietorship and at a consulting firm in various roles for six years, including as a Senior Director.

Prior to 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University, where I also minored in Mathematics. My curriculum vitae is attached as Exhibit RN-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ("PSC" OR "COMMISSION")?

A. Yes, I submitted testimony in Docket No. 20250113-EI.

Q. HAVE YOU TESTIFIED BEFORE OTHER REGULATORY JURISDICTIONS?

A. Yes. I have testified in over 95 proceedings in Alaska, Colorado, Georgia, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New

Hampshire, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, Utah, Virginia, Wisconsin, and Vermont. Among the issues covered in these proceedings were marginal and embedded cost of service studies, revenue allocation, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, DER interconnection, flexible interconnection, pre-emptive DER and load upgrades, DER compensation, DER integration, EV infrastructure investments, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, and smart inverter integration, among other topics. I have also advised the Connecticut, Colorado, Hawaii, and Kentucky state utility commissions and have testified and supported clients at the Federal Energy Regulatory Commission ("FERC").

Q. HAVE YOU TESTIFIED PREVIOUSLY ON LARGE LOAD TARIFFS AND RELATED ISSUES?

A. Yes, I recently testified on the large load tariffs of Dominion Energy ("Dominion"), Appalachian Power Company, PPL Electric Utilities Corporation, and Wisconsin Energy, and I have assisted or testified on large load issues in Arizona, Colorado, New Mexico, Illinois, North Carolina, South Carolina, Utah, Nevada, Oregon, and before FERC. I am also the Georgia Public Service Commission's expert on large load contracts, cost allocation, and rate design.

II. <u>PURPOSE AND RECOMMENDATIONS</u>

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. My testimony on behalf of the customers of Duke Energy Florida ("DEF" or "Company") through the OPC evaluates the merits and deficiencies of the Company's large load customer proposals, including the Large Load Customer Policy ("LLCP") and the Large Load Customer Agreement ("LLCA"). My testimony recommends measures the Commission can take to protect customers and comply with the requirements of Senate Bill 484 when approving a large-load tariff and cost allocation methodology.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I analyze SB 484 and the requirements it imposes on DEF to ensure that large-load customers bear the full cost of service without shifting costs to the general body of ratepayers. Then, I summarize the Company's large load proposals in this proceeding and explain why the Company's recent updates, while an improvement, remain insufficient to protect existing customers and comply with SB 484. In Section V, I discuss large-load cost allocation approaches and the relevant policy background, including why data center load is uncertain and how it can shift cost recovery risk to other ratepayers. In Section VI, I recommend how the Company should allocate incremental distribution and transmission costs to comply with SB 484, and in Section VII, I make corresponding recommendations for incremental generation costs. In Section VIII, I address additional consumer protections in the LLCP's terms and conditions, including early termination fees and security collateral. Finally, in Section IX, I summarize my recommendations and conclude my testimony.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My analysis demonstrates that DEF's proposed CIAC update, LLCA, and LLCP do not comply with SB 484. First, the Company's general theory that embedded rate treatment is sufficient for connecting and serving large loads is illogical, unsupported, and directly in opposition to emerging best practices[1] for large loads and the requirements of SB 484. Action is required from the Commission to ensure that ratemaking mechanisms are in place to allocate and recover connection and incremental transmission and generation costs with certainty to avoid cost shifting to ratepayers. Second, the Company is proposing to collect connection costs through its updated CIAC provision. However, DEF's CIAC results in identifying only a small amount of customer-specific connections costs. Instead, the Commission should consider "but for" connection costs related to large load customers that include incremental transmission upgrades, including network transmission upgrades. The customer-specific, dedicated facilities used to serve large loads should be directly allocated using a non-refundable CIAC, while upgraded facilities that are shared (e.g., shared substation and network upgrades) should be directly assigned and collected through a refundable CIAC. Third, DEF's proposed rates for large load customers, the existing GSD-1 and GSDT-1 rates, do not include embedded or incremental costs related to large load customers and are

[1] *See* Order Instituting proceeding under Section 206 of the Federal Power Act, 195 FERC 61,211, issued June 18, 2026, in Docket No. EL26-67-000. FERC calls for more transparency related to large load cost allocation and recovery including for network transmission upgrades. Additionally, FERC is requiring that ISO create flexibility and co-location processes to minimum the need for grid upgrades.

therefore not compliant with SB 484. Fourth, DEF has not analyzed or included incremental generation costs associated with large load customers. This is, again, in direct opposition to SB 484, and the Commission should require the Company to create an incremental generation charge that is in addition to the embedded cost rate paid by large load customers. Finally, assuming the above improvements are made, I recommend further changes to the early termination fees and security collateral to ensure costs are not shifted onto other ratepayers.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on my review of the Company's large load proposals and my understanding of the requirements of SB 484, I make the following recommendations to the Commission:

1. Decline to approve DEF's LLCA, LLCP, CIAC proposals as filed.
2. Explicitly note in the Commission's order that any large load agreements should be considered contingent on DEF's future large load customer tariff and associated rules and regulations to avoid allowing projects to move forward and shift costs onto other ratepayers.
3. Direct DEF to refile its large load customer proposals to incorporate the following modifications:
    a. Require DEF to allocate the incremental transmission and distribution costs caused by large load customers directly to those customers, using a tiered connection-cost framework. Under this framework all customer-specific, dedicated transmission facilities needed to serve a large load customer should

be directly allocated to that customer through an up-front CIAC payment with no refund. Additionally, upstream from customer-specific facilities, all “but for” connection and incremental transmission, including network upgrade, costs incurred to connect a large load should be recovered through CIAC subject to a refund period of up to 15 years. Implementation of this recommendation can be accomplished by either defining “but for” transmission costs as excess facilities within an LLCA or by further modifying the Company’s line extension policies or LLCA to include these costs within the CIAC provision.

b. Require DEF to recover incremental generation costs directly from large load customers, and to track costs for future cost increases or overruns to ensure these costs are not shifted to other ratepayers.

c. Require DEF to amend the early termination provision of its LLCP so that the termination fee equals the customer’s minimum monthly bills for the entire remaining contract term, regardless of the contract year in which the customer elects to terminate service.

d. Require DEF to replace its open-ended, negotiated security collateral provision with clear and specific parameters set at a higher level-security collateral equal to 24 months of minimum bills based on the customer’s planned post-ramp peak demand.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Utilities are currently in a competitive race to connect large loads, and many are relying on closed-door negotiations and contracts to attract large loads. At the same time, regulators throughout the country are grappling with how to integrate and allocate costs to large loads. It is important for regulators to create regulatory mechanisms that carefully track the information used to inform utility decisions, increase transparency within contracting processes, and ensure detailed records of incremental system upgrades caused by large loads.[2] In the race to connect large loads, regulators must keep prudent decision making at the forefront and, to do this, a transparent record must be built now.

III. POLICY ANALYSIS

Q. WHAT IS YOUR UNDERSTANDING OF SB 484 AS A NON-LAWYER EXPERT IN THIS FIELD?

A. SB 484 was passed by the Florida Legislature this year and signed by Governor DeSantis on May 7, 2026. SB 484 adds Section 366.043 to the Florida Statutes, effective July 1, 2026. This new section includes legislative findings and requirements for public utilities regarding the connection and service of new customers with 50 MW of load or more.

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[2] *See* Order Instituting proceeding under Section 206 of the Federal Power Act, 195 FERC 61,211, Issued June 18, 2026, in Docket No. EL26-67-000. FERC has ordered large load contracts with transmission operators to be filed at FERC. Stakeholders have argued that the Chevron Doctrine should not apply to these contracts as Contracts between large load companies and utilities can harm ratepayers while enriching both parties with little to no transparency.

Q. PLEASE DESCRIBE THE LEGISLATIVE FINDINGS CONTAINED IN SB 484.

A. In §366.043(1), Florida Statutes, the Legislature finds "that when one class of electric service customer requires uniquely large electrical load at a single location, it imposes a disproportionate risk on the other ratepayers of this state and makes it necessary for the commission to develop and enforce rate structures and other policies for such customers which ensure such risk is mitigated as much as possible and prevent shifting of the costs of service large load customer to the general body of ratepayers."[3]

Q. TO ADDRESS ITS CONCERNS REGARDING NEW LARGE LOAD CUSTOMERS, WHAT REQUIREMENTS DID THE LEGISLATURE IMPOSE ON PUBLIC UTILITIES?

A. The Legislature further requires public utilities to develop minimum tariff and service requirements that "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. Such cost of service includes, but is not limited to, connection, incremental transmission, incremental generation, and other infrastructure costs; operations and maintenance expenses; and any other costs required to serve a large customer."[4]

Q. DID THE LEGISLATURE DEFINE WHAT IT MEANS BY COST OF SERVICE?

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[3] § 366.043(1), Florida Statutes.
[4] § 366.043(3)(a), Florida Statutes.

A. Not in exacting detail. As discussed throughout my testimony, the term cost, or cost of service, has many dimensions (e.g., temporal) to it and can be interpreted in many ways. However, the legislation provides some non-exhaustive examples of what the cost of service includes and requires that the risk of the nonpayment of such costs may not be borne by the general body of ratepayers. Further, the Commission's broad authority to set fair, just, and reasonable rates arguably authorizes the Commission to define a large load customer's full cost of service in a way that shields the current body of ratepayers from cost shifting throughout the life of the costs caused by large load customers.

Q. WHAT IS YOUR HIGH-LEVEL SUMMARY OF THESE LEGISLATIVE REQUIREMENTS?

A. While I am not a lawyer, based on my experience and expertise, I interpret these findings and new requirements as an acknowledgment by the Legislature that new large loads, such as data centers, present new and unique risks and have the potential to shift costs to other ratepayers. The legislative intent portion finds that such risks require the Commission to develop new policies and rate structures to mitigate these risks and prevent cost shifting by ensuring that each large load customer pays for its full cost of service. This full cost of service includes, but is not limited to, all the connection and incremental costs incurred to serve large load customers as well as any other costs the Commission should deem necessary to insulate other ratepayers.[5]

[5] § 366.043(3)(a), Florida Statutes, states, "The risk of nonpayment of such costs may not be borne by the general body of ratepayers."

Q. HOW DOES DEF CHARACTERIZE THE COSTS AND RISKS FROM NEW LARGE LOADS?

A. DEF witness Wishart states that "while data centers may be a relatively new development, there is no requirement to treat them differently than how new customers have been treated over the past 100 years."[6] Based on this conclusion, DEF proposes to charge new large load customers based on the embedded cost-of-service approach and to use existing line extension policies, rather than charging customers based on the unique connection and incremental costs caused to serve new large load customers.[7]

Q. IS IT YOUR OPINION THAT SB 484 REQUIRES UTILITIES TO TREAT CUSTOMERS IMPOSING OVER 50 MWS OF DEMAND DIFFERENTLY THAN CUSTOMERS HAVE BEEN TREATED OVER THE LAST 100 YEARS?

A. Absolutely. The Legislature would not have wasted significant time drafting and considering a bill that could be summarized, as DEF suggests, to treat large load customers the same as you always have. Such an interpretation of the legislation is illogical as it assumes legislators drafted policy endorsing the status quo for large load cost allocation, and ignores the intent of the legislation which is clear – to create a new regulatory paradigm that ensures large loads pay their just and reasonable full cost of service and do not shift costs to other ratepayers. DEF has failed to propose a tariff that satisfies the requirements of SB 484.

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[6] Wishart Direct 16:6-7.

[7] Wishart Direct 16:19-17:15.

Q. DOES DEF INCLUDE ANY ANALYSIS TO SUPPORT ITS ASSERTION THAT CHARGING LARGE LOAD CUSTOMERS AVERAGE EMBEDDED COSTS WILL PAY FOR THEIR FULL COST OF SERVICE, INCLUDING CONNECTION AND INCREMENTAL COSTS INCURRED TO SERVE THEM THROUGH AN EMBEDDED COST OF SERVICE METHODOLOGY?

A. No, it does not. When asked in a deposition, DEF witness Wishart stated that "it's been my experience that charging average embedded costs more than covers the incremental cost of transmission and incremental cost of generation."[8] The witness goes on to state that, in his opinion, charging customer rates based on the average embedded costs would be in compliance with SB 484.[9] Witness Wishart provides no support for this claim and the Company provided no supporting analysis either.

Q. WHAT IS YOUR HIGH-LEVEL RESPONSE TO THIS ASSERTION?

A. I disagree with DEF's and witness Wishart's conclusions, and will explain why witness Wishart's statement is misleading. As I will discuss in more detail below, the DEF proposal does not comply with the statutory requirements that large loads pay their full cost of service, including connection and incremental generation and transmission costs, nor does it mitigate the costs and risks shifted to other ratepayers. In the remaining sections of my testimony, I will explain why the tariff does not comply with SB 484 and provide recommendations on how a tariff can comply with these statutory requirements.

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[8] Wishart Deposition 28:25-29:3.
[9] Wishart Deposition 29:15-20.

IV. THE COMPANY'S LARGE LOAD PROPOSALS

Q. PLEASE SUMMARIZE THE COMPANY'S LARGE LOAD CUSTOMER PROPOSALS IN THIS PROCEEDING.

A. The Company is proposing to add a LLCP to its tariffs in this proceeding that will apply to all new customers with load greater than 50 MW.[10] To implement these requirements, the Company has also included a LLCA that such customers must sign, based on the requirements of the LLCP.[11] Finally, the Company proposes changes to its CIAC tariff to implement a portion of the LLCP that requires the total estimated costs to extend service to be paid up front by new large load customers and refunded over a period of up to five years, based on its existing line extension rules.[12]

Q. IS THE COMPANY PROPOSING A NEW RATE CLASS FOR LARGE LOAD CUSTOMERS IN THIS PROCEEDING?

A. No, it is not. The LLCP requires large load customers to take service under the Company's existing GSD-1 or GSDT-1 rate until the Company presents a new large load rate schedule in its next rate case.[13] So, while the Company implies that it will eventually establish a new rate class for large load customers, it does not propose one in this proceeding.

[10] Chatelain Direct at 5 :8-16.
[11] Chatelain Direct at 6:8-13.
[12] Chatelain Direct at 5 :17-21.
[13] LLCP at 4.

Q. DO THE EXISTING GSD-1 AND GSDT-1 TARIFF INCLUDE ANY CONNECTION OR INCREMENTAL COSTS ASSOCIATED WITH LARGE LOADS?

A. It is unclear, but unlikely that substantial large loads are included. The rates for GSD-1 and GSDT-1 were set in DEF's previous rate case, so they do not likely contain significant large load related costs within these rates.[14] However, DEF is already incurring some costs related to large loads. For example, DEF is conducting system impact studies, conducting planning studies, and working directly with large load customers. These studies are resource intensive and utilities spend significant resources negotiating contracts and interfacing with large load customers to get them to locate in their jurisdiction.[15] In keeping with DEF's "data centers are just customers we have a duty to serve" approach, it does not appear that DEF is making any attempt to identify, capture, and apply these costs to the cost causer. This business as usual approach strongly suggests that the general body of ratepayers is already at risk for subsidizing these costs. Furthermore, the obligation to serve does not explicitly mean firm service or traditional service. In fact, to ensure just and reasonable rates, utilities must modify service offerings and regulatory processes to avoid excessive cost shifting to other customers.

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[14] DEF could be building, and putting into service, assets for large loads prior to their energization, which would be a clear cost shift and in violation of SB 484.

[15] On May 5, 2026, Duke Energy CEO Harry Sideris stated, "we have a team in place that their goal 7 days a week, 24 hours a day is how do we get these things signed quicker, how do we service them quicker." *See* Duke audio webcast at 31:35, https://events.q4inc.com/attendee/939851751/guest.

Q. PLEASE SUMMARIZE THE CHANGES THAT DEF MADE TO THE LLCP AND LLCA AS COMPARED TO ITS INITIAL FILING IN SEPTEMBER 2025 IN RESPONSE TO SB 484 AND PREVIOUS TESTIMONY SUBMITTED IN DOCKET NO. 20250113-EI.

A. DEF originally filed for approval of its LLCP and LLCA in September 2025 in Docket No. 20250113-EI. Following the passage of SB 484, the Company retracted its petition and filed an updated petition in April 2026. The updates the Company has made include amending several of the LLCP and LLCA's terms and conditions to provide greater protection to existing customers and to comply with requirements under SB 484. These changes include:

1. Reducing the threshold for applicability of the LLCP from 100MW to 50MW;
2. Increasing the minimum LLCA term from 15 years to 20 years;
3. Increasing the termination fees to three years of minimum bills plus the net book value of CIAC facilities;
4. Including a minimum load factor of 60% for calculating a minimum energy charge as part of the monthly minimum bills; and
5. Removing flexibility from the CIAC provision, requiring all customers to pay CIAC upfront, subject to refunds over a five-year period.

Q. ARE THESE CHANGES SUFFICIENT TO PROTECT CUSTOMERS AND COMPLY WITH SB 484?

A. No. The updates that DEF have made to the LLCP and LLCA are incremental progress and include several recommendations that I made in direct testimony filed in Docket

No. 20250013-EI, such as lowering the applicability threshold to 50MW and including a Minimum Billing Energy Volume in monthly minimum bills that is calculated based on a 60% load factor. Although these changes represent some progress, the updates DEF has made are not sufficient to adequately protect existing customers from cost shifting and, as I stated above, do not comply with the requirements of SB 484 that large loads must pay for connection and incremental costs incurred to serve them. Specifically, the Company's definition of connection costs is overly myopic and does not include all "but for" connection or incremental costs, and the Company has no process for estimating, allocating, and recovering incremental transmission and generation costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION CONCERNING LARGE LOADS AND THE IMPLEMENTATION OF SB 484.

A. In the remainder of my testimony, I make recommendations concerning the allocation of incremental generation and transmission costs to customers covered under the LLCP. For all transmission, distribution, and generation costs, this allocation would require a large load customer to pay for all "but for" incremental costs incurred as a result of the new customers. I will discuss these recommendations in more detail below.

Q. OTHER THEN COST ALLOCATION, DO YOU HAVE OTHER RECOMMENDATIONS REGARDING THE LLCP?

A. Yes, I do. Adopting my recommendations for allocating connection and incremental generation and transmission costs would provide much stronger protections for existing customers consistent with the intent of SB 484. Additionally, I have recommendations to the Commission to strengthen the terms of the LLCP, which I discuss in more detail in Section VIII below.

V. LARGE LOAD COST ALLOCATION AND POLICY BACKGROUND

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the various approaches to cost allocation of generation and transmission costs that can be used to allocate costs to large load customers and highlight pros and cons of the different methods as it relates to implementing the requirements of SB 484. I also discuss some of the risks and costs associated with data center growth in general, and how other jurisdictions are addressing these risks and costs.

A. LARGE LOAD COST ALLOCATION APPROACHES

Q. ARE THERE ANY RATEMAKING CONCEPTS THAT ARE IMPORTANT TO UNDERSTANDING DATA CENTERS' IMPACTS ON OTHER CUSTOMERS' RATES?

A. Yes. Average embedded cost of service, incremental cost allocation, or a combination of both can be used to establish rates for new customers, including new data centers and other large-load customers. The cost allocation method a utility chooses will significantly impact the rates new and existing customers will pay as well as the risks those customers will bear. In particular, whether existing customers are protected from short-term rate impacts and whether potential benefits to other customers materialize over the long-term are closely related to how costs are allocated to new customers. This is particularly true for new data centers or other large load customers that trigger extremely large incremental costs to serve them. In addition, ensuring that new large customers pay for all incremental costs is necessary to comply with SB 484's requirements that costs are not shifted from large loads to other ratepayers.

Q. CAN YOU EXPLAIN HOW THE AVERAGE EMBEDDED COST OF SERVICE METHOD WORKS REGARDING LARGE LOADS?

A. At a high level, under an embedded cost of service approach, a utility determines its total revenue requirement both for new investments required to serve large loads as well as all of its historical investments in the electric grid, functionalizes those costs into categories such as production, transmission, and distribution costs, and allocates those costs to each customer class using allocation factors. Allocation factors may be related to the number of customers, energy usage, maximum demand for each customer class, or other metrics. The average embedded cost approach treats new customers and existing customers the same, allocating costs to each in the same manner.[16]

Q. CAN YOU EXPLAIN HOW INCREMENTAL COST OF SERVICE WORKS?

[16] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. "Electric Cost Allocation for a New Era: A Manual" at 29. Montpelier, VT: Regulatory Assistance Project. Available at: https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

A. Utilities can also allocate costs to new customers based on the incremental cost to serve those customers. Under this approach, the new load is directly allocated the incremental cost to serve it in one or more functional categories. While the customer will pay the incremental costs for new resources, it will likely not be charged the costs of system expansion required to serve subsequent new customers or the costs of the existing system.[17] Allocating the incremental cost to new customers can protect existing customers from short-term rate increases and, potentially, insulate customers from risks of stranded assets associated with large loads. However, existing customers may not benefit from potential future rate reductions from new large loads if those costs are all directly allocated to large loads.

Q. ARE THERE HYBRID APPROACHES THAT COMBINE THESE TWO COST ALLOCATION APPROACHES?

A. There are a number of hybrid approaches to allocating costs, many of which draw on FERC cost allocation precedent for "but for" upgrades.

Q. WHAT IS THE "BUT FOR" STANDARD FOR IDENTIFYING TRANSMISSION UPGRADE COSTS THAT COULD BE ALLOCATE TO A SPECIFIC CUSTOMER?

A. The "but for" standard is the foundational principle of cost causation in transmission interconnection at FERC.[18] Under this standard, a network upgrade is deemed to be caused by a specific customer if that upgrade would not have been constructed but for

[17] Lazar et al. at 29.
[18] See FERC Order 2003.

that customer's request for interconnection or service. Costs that meet the "but for" test are properly allocated entirely to the cost-causing customer, regardless of whether other customers may derive incidental benefit from the upgrade.

Q. HOW DOES FERC ALLOCATE TRANSMISSION COSTS THAT MEET THE "BUT FOR" STANDARD?

A. One method used by FERC is the "higher of" principle. This principle governs the rate a customer pays when it requests new capacity that necessitates incremental system expansion. Under this principle, the customer seeking expanded capacity pays the higher of two amounts: the existing rolled-in system rate or the incremental cost of constructing the new facilities required to serve that customer's load. The customer may not elect to pay only the existing system average rate when doing so would require other ratepayers to subsidize the incremental infrastructure costs triggered by the new customer's demand.[19]

Q. WHAT IS THE POLICY RATIONALE FOR THE "HIGHER OF" PRINCIPLE?

A. The rationale has two components. First, it enforces cost causation: a customer who triggers new infrastructure construction should not be subsidized by existing ratepayers simply because the incremental cost exceeds the system average. Second, it prevents strategic behavior: without the "higher of" floor, large customers could extract a subsidy by arguing that they are entitled to pay only the embedded system average rate

[19] See FERC Order 2003.

while the incremental cost of serving them — which may far exceed that average — is spread across all ratepayers.[20]

Q. WHAT IS IMPORTANT TO UNDERSTAND ABOUT "HIGHER OF" PRICING?

A. The "higher of" pricing principle uses a more expansive definition of incremental cost than DEF's CIAC proposal. DEF is essentially identifying "customer-specific" or dedicated facilities as incremental, while "but for" incremental costs would expand beyond this definition into network transmission upgrades and lines that run from a substation to the bulk transmission system. Additionally, even under the more expansive "but for" definition, over a long period of time (e.g., 20 years) customers would often pay less when assigned the incremental costs when compared to embedded costs. Or at least this was true prior to unprecedented large load customers we are currently discussing. For this reason, hybrid approaches can be used to ensure that large loads pay the near-term incremental costs while still paying the higher embedded costs over time. For example, CIAC payments that reflect "but for" incremental costs, with a refund plus the embedded rate, ensure that large loads bear all incremental costs as a floor while maintaining the potential upside that can come from embedded rates over the long term.

Q. ARE THERE OTHER HYBRID PRICING APPROACHES FOR ALLOCATING TRANSMISSION COSTS USED BY FERC?

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[20] See FERC Order 2003.

A. While FERC policy prohibits "and pricing" where the same customer pays both an existing transmission rate and a separate new charge for the same transmission service or the same increment of capacity, there is no such prohibition from separating the cost of pre-existing shared infrastructure from the cost of new dedicated infrastructure triggered by a specific customer's interconnection request. When the two components are properly disaggregated, there is no double-billing: one rate pays for pre-existing network facilities that serve all customers, and the incremental charge pays for new facilities that would not exist "but for" the specific customer. Under "and pricing" the customer separately pays for its incremental costs as well as embedded costs through separate rates. This concept is similar to the incremental generation charge ("IGC") proposed by Florida Power & Light ("FPL") because it charges an incremental amount above the embedded rate directly attributable to large load customers. A similar approach can be taken with transmission. FirstEnergy's supplemental comments in FERC ANOPR RM26-4 make this point directly: the two-component rate structure does not constitute "and pricing" because "the existing [system] rate covers pre-existing infrastructure" while "the expansion rate covers new facilities."[21]

Q. WHAT CAN THIS COMMISSION LEARN FROM THE FERC TRANSMISSION COST ALLOCATION PRECEDENT YOU'VE DISCUSSED?

A. While DEF has sought to cast cost allocation as a binary choice between incremental costs and embedded costs, there are hybrid approaches available to the Commission. The hybrid approaches can avoid shifting costs to other ratepayers in the near term,

[21] *FirstEnergy Supplemental Comments, RM26-4 (June 5, 2026).*

while also allowing for a long-term benefit if embedded costs exceed incremental costs and the customer maintains its load over time. The hybrid approaches would also align with SB 484, while DEF's proposed approach does not because it fails to identify all "but for" connection and incremental transmission and generation costs.

B. DEF COST ALLOCATION PROPOSAL

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE COSTS TO LARGE LOADS IN THIS PROCEEDING?

A. While it is not totally clear how the Company will establish future rates for large loads given that it proposes that rates will be established in a future rate case, the Company spends much of its filing discussing the benefits of the average embedded cost methodology and the challenges with other approaches.[22] In addition, as I discussed above, in a deposition OPC conducted in this proceeding, DEF witness Wishart further stated his opinion that the average embedded cost approach would be in compliance with SB 484.

Q. WHAT REASONS DOES THE COMPANY PROVIDE FOR PROPOSING THE AVERAGE EMBEDDED COST APPROACH?

A. The Company primarily uses the concept of fairness to justify its proposal to use the average embedded costs for large load customers. Company witness Wishart states that embedded system costs ensures fairness across customer classes and is consistent with

[22] Wishart Direct at 15:10-20:9.

how the Company treats other new customers that join the system.[23] In addition, DEF also stated that by only charging a data center customer incremental costs, a utility would likely undercharge when compared to the average embedded cost approach.[24] Further, he states that "while data centers may be a relatively new development, there is no requirement to treat them differently than how other new customers have been treated over the past 100 years."[25]

Q. DO YOU AGREE WITH MR. WISHART'S ASSESSMENT THAT THERE IS NO NEED TO TREAT DATA CENTERS DIFFERENTLY THAN OTHER NEW CUSTOMERS?

A. I do not, and as I discussed above, the Legislature also does not. As Mr. Wishart notes, there has been "unprecedented growth in the U.S. data center industry in recent years."[26] In addition, the data centers currently proposed and under construction represent new loads of unprecedented size that require unprecedented system upgrades to serve. The cost allocation paradigm we've been using for 100 years was not designed to accommodate such large and unprecedented load growth. For example, DEF states that it has received inquiries from data centers representing 13.2 GW of additional capacity.[27] If all this new data center capacity were to interconnect, it would more than double the Company's 2024 net firm demand of 8.6 GW.[28] The unprecedented size and

[23] Wishart Direct at 19:6-8.
[24] Wishart Deposition 31:1-8.
[25] Wishart Direct at 16:6-7.
[26] Wishart Direct at 3:15-17.
[27] Exhibit RN-2 - DEF Response to Interrogatory 24(c).
[28] DEF 2025 Ten Year Site Plan at 2-15. Available at https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/Duke%20Energy%20Florida.pdf.

scale of data centers create new risks and mean that frameworks that have worked well to create fair cost allocation outcomes in the past will not necessarily work as well in the future.

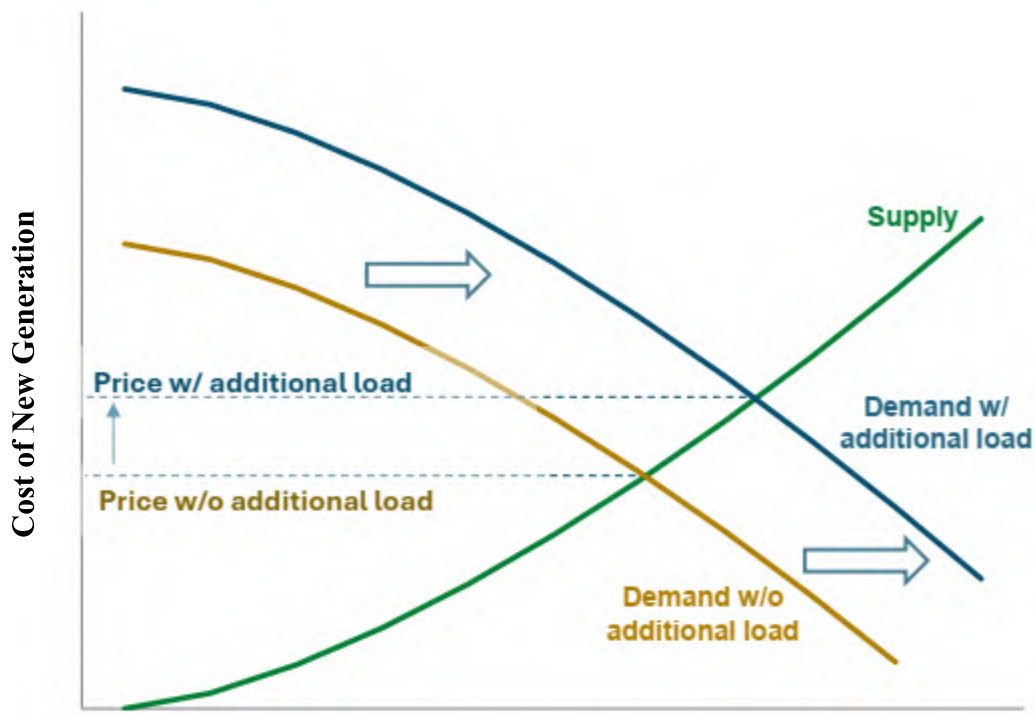
Q. WHAT ARE THE RISKS TO OTHER CUSTOMERS FROM USING THE AVERAGE EMBEDDED COST METHODOLOGY TO ALLOCATE COSTS TO LARGE LOADS?

A. Serving new loads that could more than double the capacity of the electric grid in less than a decade will require investments in incremental generation and transmission infrastructure at an unprecedented speed and scale. Such rapid, large-scale investment will increase prices for new generations, as costs move up the supply curve for new generation resources, raising the marginal price for supply to serve all load. This concept is well articulated in a study commissioned by the Virginia Joint Legislative Audit and Review Commission ("JLARC"), a government entity in Virginia that conducts program evaluation, policy analysis, and oversight of state agencies on behalf of the Virginia Legislature.[29] Virginia is the largest data center market in the world and is grappling with the complex policy challenges related to the impact of data centers on electricity prices and markets. As shown in Figure 1, below, as load increases, the marginal cost to add additional load also increases as demand for new generation resources outstrips the available supply. This concept can be seen in the recent escalating costs of new gas-fired power plants. Due to significant demand for new generation, as well as inflation, recent prices for combined cycle natural gas generators

[29] Exhibit RN-3: Virginia Joint Legislative Audit and Review Commission, Data Centers in Virginia Report. December 9, 2024 https://jlarc.virginia.gov/pdfs/reports/Rpt598-2.pdf ("JLARC Report").

have increased from between $1,116-$1,427 per kw to $2,000 or more per kw in just a few years.[30] Much of the increase is driven by rising electricity demand to power new data centers, creating a backlog and significant waiting lists for new generators. The result of this phenomenon is that the marginal cost to serve this unprecedented new load will be significantly higher than the average cost of historical resources serving existing customers.

Figure 1[31]



Q. IF THE MARGINAL COST TO SERVE NEW GENERATION IS HIGHER THAN THE AVERAGE SYSTEM FIXED COSTS, WHAT WILL BE THE IMPACT ON EXISTING CUSTOMERS' RATES?

[30] The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S. at 4. Available at https://gridlab.org/portfolio-item/gas-tubine-cost-report/.
[31] Exhibit RN-3 - JLARC Report at 80.

A. If the marginal cost to serve a new customer is higher than the average embedded cost of the system, and average embedded costs are allocated to the new customer, there would be a shortfall between what the new customer pays and the costs they caused. The gap between costs caused and allocated would need to be paid for by existing customers, increasing their rates in the short term. Adding the new, more expensive assets to the system will raise the average costs which are allocated to all customers, which will, in turn, raise rates. This will happen even if new large loads are allocated their share of average embedded costs. In addition, as embedded costs are allocated to rate classes using allocators, a portion of the socialized embedded costs will also be allocated directly to existing customers in other rate classes under the embedded cost approach. This shifts costs to other ratepayers in direct conflict with SB 484.

Q. ARE THERE POTENTIAL LONG-TERM BENEFITS FROM USING THE AVERAGE EMBEDDED COST ALLOCATION APPROACH?

A. Over time, if the expected load from large customers is maintained and the need to build new resources slows, rates for other customers may decline relative to what they otherwise would have been.[32]

Rates may decline on a relative basis because the utility's rate base decreases over time due to depreciation, which will lower the utility's overall revenue requirement. While costs decline, the utility's total sales and demand are much larger than they otherwise

[32] This statement is based on an assumption that "all else is equal." This is not a reasonable assumption within the current regulatory framework because utility's have a bias towards investing in capital to increase earnings. Said another way, if rates go up because of data centers, utilities have a strong incentive to maintain or accelerate investments to keep rates from actually going down. Over the more than 100 years of electricity regulation, there are very few instances, comparatively, where utilities request rate decreases as opposed to increases, so suggesting that rates will fall because of data centers is extremely unlikely under the current regulatory framework.

would have been because of the new large load customer. In other words, the system's costs are now spread out over more kilowatt-hour sales. Eventually, new large load customer's contribution to paying for the system's fixed costs may exceed the amount by which the new large customer's marginal costs were initially subsidized by existing ratepayers.

Importantly, the breakeven point for customers that require hundreds of megawatts of new generation and transmission resources to be added to the grid at relatively high marginal costs can be a decade or more in the future. In the interim, other customers pay higher rates than they would have under a different cost allocation methodology.

Q. WILL DEMAND GROWTH IN DEF'S SERVICE TERRITORY FROM DATA CENTERS NECESSITATE INVESTMENT IN NEW INFRASTRUCTURE?

A. DEF has stated that its current projected reserve margin would not support a 500 MW increase in load, nor would it be able to construct new resources to support 500 MW of new load by December 2028.[33] This fact alone shows that substantial new loads taking service under the tariff proposed in this proceeding will require the construction of incremental generation resources. While it is more challenging to make a generalization regarding transmission upgrades for DEF, given that the transmission network upgrades required to connect data centers are extremely locationally dependent and rely on the locational topology of the transmission network, there will likely be significant transmission upgrades needed to interconnect new data center load as shown in other jurisdictions.

[33] DEF Response to Staff's interrogatory request 19-a. in docket no. 2025-0113-EI.

Q. HAS DEF PRESENTED ANY EVIDENCE QUANTIFYING ITS ASSERTION THAT EMBEDDED RATES WILL COVER THE FULL CONNECTION AND INCREMENTAL COST OF GENERATION AND TRANSMISSION RESOURCES?

A. No, it has not.[34]

Q. HAS DUKE ATTEMPTED TO QUANTIFY THE QUANTITY OF BENEFITS TO OTHER CUSTOMERS IN ANOTHER JURISDICTION?

A. Yes, it has. In Rebuttal testimony in Docket No. E-100, Sub 207 in North Carolina, Duke provided a large load impact analysis, which it states, "seeks to address whether the revenue paid by large load customers will exceed the incremental cost to serve such customers."[35]

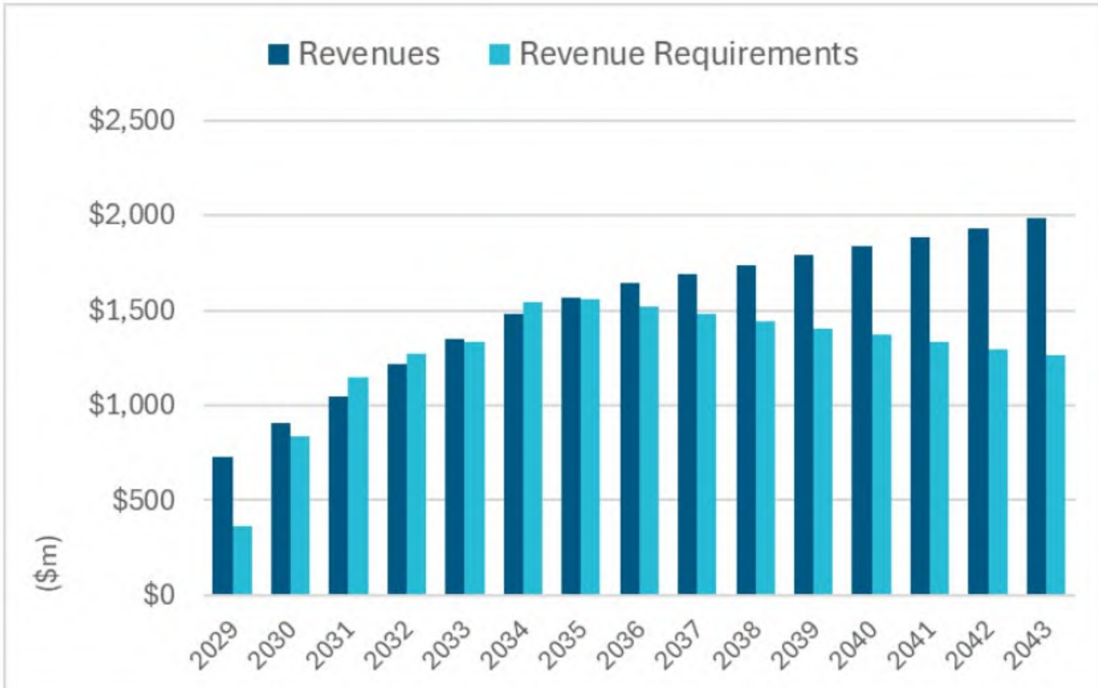
Q. What does Duke's analysis in that proceeding show?

A. I have pasted Figure 2 sourced from Duke's analysis below.

[34] Wishart Deposition 32:20-33:2

[35] North Carolina Public Utilities Commission, Docket No. E-100, Sub 207, Rebuttal Testimony of Bateman and Beveridge, 5-6.

Figure 2: Duke Large Load Impact Analysis – Annual Revenues and Revenue Requirement



Q. DO YOU HAVE ANY CRITIQUES OF THIS ANALYSIS?

A. I do not have access to the workpapers, calculations, and assumptions behind this analysis as it was conducted for a different proceeding, but after reviewing it at a high level I do have a few critiques. First, the analysis does not begin until 2029, once a significant amount of new revenues is forecast. I assume beginning the analysis earlier would remove some of the first-year benefits as costs will be incurred prior to 2029 without corresponding revenues. Second, the analysis just shows the ability for new load to pay for the incremental revenue requirement of new resources. It does not show any contribution from new load to paying for the existing generation and transmission embedded system costs, which it will also use and should pay for. Third, the analysis assumes that the expected load fully materializes and is maintained, which, as I will discuss, is not certain for large loads such as data centers and undermines the entire concept of paying for incremental costs. Fourth, it's not clear whether the revenues are limited to those in cost categories associated with the infrastructure upgrades or whether they include other revenues, such as fuel costs, which would not be an appropriate comparison.

Q. EVEN WITH THESE CRITIQUES, WHAT DOES THE ANALYSIS SHOW?

A. The analysis shows that any benefit to other ratepayers does begin to accrue in a material way only in 2036, ten years into the future. If revenues from new customers are lower than expected due to lower usage or a customer terminating its contract, the benefits would not materialize until much later, if at all. It certainly does not demonstrate that an embedded cost paradigm will ensure no cost shifting as required by SB 484. Under DEF's proposal in this proceeding, during the contract's early years, all other customers will pay a portion of the incremental costs to serve this new load, thereby increasing rates, with any benefits to other customers not materializing until far in the future.

Q. HAVE OTHER ENTITIES IN NORTH CAROLINA ANALYZED WHETHER A LARGE LOAD CUSTOMER WILL PAY ITS FULL INCREMENTAL COSTS UNDER DUKE'S EMBEDDED COST APPROACH?

A. Yes, North Carolina Public Staff conducted its own analysis based on its review of an ESA for one specific large load customer. This large load customer created approximately $140.4 million in interconnection costs, but the North Carolina Public Staff's calculations show that the customer would only be expected to contribute roughly $2.48 million towards those costs over its 15-year contract term.[36] This leaves a $137.9 million gap between the embedded rates paid by the customer and the upgrades it caused, which will be shifted to other rate classes. DEF has provided no information to suggest the proposal in this proceeding would result in a different outcome.

North Carolina Public Staff identified that the gap between embedded rates and incremental costs arises in large part because of insufficiencies in Duke's CIAC policy. Duke only requires new customers to provide CIAC when newly constructed facilities will not provide sufficient revenue to support the investment, which appears consistent with DEF's line extension rules. Though this policy has worked well historically, Public Staff identified three problems with using this approach, without modification, when investments are being made to support customers adding tens or hundreds of MWs of new demand to the system: the scale of investments being made to serve large load customers is different than those made historically and this reality should be—but is not currently—reflected in the test used; the calculation does not consider allocation factors, leading the CIAC test to overestimate the revenues that will be used to pay for new investments; and the revenue component of the CIAC test includes items such as fuel that should not be counted towards the cost of new infrastructure. [37] The issues that North Carolina Public Staff identified with Duke's CIAC policy are similar to the issues with the policy DEF has proposed, which I discuss in more detail below.[38] In both cases,

[36] North Carolina Utilities Commission, Docket No E-7, Sub 1329. Testimony of Jay Lucas, Jethro Sengonzi, and Leah Weaver at 54:5-55:10.
[37] North Carolina Utilities Commission, Docket No E-7, Sub 1329. Testimony of Jay Lucas, Jethro Sengonzi, and Leah Weaver at 48:7-52:16.
[38] See https://www.law.cornell.edu/regulations/florida/Fla-Admin-Code-Ann-R-25-6-064.

requiring insufficient (i.e., customer-specific versus "but for" costs) upfront investment from large load customers leads to insufficient protection against cost shifting and a timing mismatch between when costs are incurred and when they are recovered, leading to short-term rate increases.

Q. HOW DOES THIS CONCERN RELATE TO THE REQUIREMENTS OF SB 484?

A. As I stated above, when large new loads require significant investments to serve them, costs and risks will be shifted to other customers in the short- to medium-term under the average embedded cost approach to ratemaking. Thus, under the Company's approach, one would expect rates to increase for all other customers in the short term as a result of this cost shift. This aspect of DEF's proposal directly violates the requirements of SB 484.

Q. DID THE COMPANY SUBMIT ANY TESTIMONY ON THE RELATIONSHIP BETWEEN NEW DATA CENTER LOAD AND ELECTRICITY RATES?

A. Yes. Company witness Wishart suggests data centers and other large load customers can help lower the average per unit cost of electricity delivered because they consistently use electricity throughout the day and across seasons, improving the overall utilization of generation, transmission, and distribution infrastructure.[39] Mr. Wishart uses national data on total electric sales volumes, the average price of electricity in the US, and inflation to compare inflation-adjusted electricity prices to

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[39] Direct Testimony of Steven Wishart at 6:19-23.

annual total sales volume. His data shows that from 1979 to 2004, electric sales consistently grew and the average inflation adjusted price fell, while from 2004 to 2024, electric sales and inflation adjusted prices were both steady.[40] Mr. Wishart also runs a second analysis comparing the change in sales volume and the change in average rates from 2015 to 2024 for individual utilities and finds a statistically significant negative correlation between the percentage change in sales and the percentage change in average rates.[41]

Q. WHAT IS YOUR REACTION TO MR. WISHART'S ANALYSES COMPARING ELECTRICITY SALES AND ELECTRICITY PRICES?

A. Mr. Wishart's analyses are of limited, if any, use in this proceeding. All else equal, Mr. Wishart is correct that increasing the utilization of existing infrastructure leads to lower electricity rates for all customers. However, as he notes, many factors influence electricity prices, and the relationship he observed "does not imply that in the future, incremental load growth will lower inflation adjusted electric rates."[42] There are reasons to believe that this relationship will look different in the future. Specifically, as Mr. Wishart states, "unprecedented growth in the U.S. data center industry" is occurring and is expected to continue accelerating.[43] Because of this, data centers will not simply increase utilization of existing infrastructure but will necessitate significant incremental investment in new infrastructure to serve them. Without reasonable changes to the regulatory framework, including cost allocation, these infrastructure

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[40] Direct Testimony of Steven Wishart at 7:19 – 8:6.
[41] Direct Testimony of Steven Wishart at 8:14 – 9:7.
[42] Direct Testimony of Steven Wishart at 8:4-6.
[43] Direct Testimony of Steven Wishart at 3:15-17 and at 4:9-19.

upgrades will largely be socialized. This will cause an increase in rates in the short and medium term that will only lead to potential bill savings for customers if data center load is maintained for an amount of time where the embedded rates paid by these customers cover the initial incremental increase.

Q. WHAT EVIDENCE IS THERE TO SUGGEST THAT LARGE LOADS ARE PUTTING UPWARD PRESSURE ON GENERATION COSTS, LEADING TO RATE INCREASES?

A. In addition to the example from North Carolina, discussed above, the Independent Market Monitor for PJM released a report in June 2025, which found that data center load growth was directly responsible for the extremely high prices observed in the PJM Base Residual Action ("BRA") for capacity. In particular, the authors wrote "data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the tight supply demand conditions, the high prices observed in the BRA for 2025/2026 or the high prices expected for the 2026/2027 and subsequent capacity auctions."[44] PJM is ahead of many jurisdictions with seeing data center impacts because there are large hubs developing in Virginia, Pennsylvania, and Illinois. However, it is likely that the generation and transmission rate increases

[44] The Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction, Part G. June 3, 2025. Available at: https://www.monitoringanalytics.com/reports/reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf.

experienced within PJM will translate to other jurisdictions as development of data centers increases in other markets.

Q. WHAT ARE THE IMPACTS OF TRANSMISSION UPGRADES NECESSARY TO SERVE DATA CENTERS IN PJM?

A. One report estimated that in 2024 alone, utilities in seven PJM states socialized more than $4.3 billion in transmission costs to utility customers to provide service to data centers.[45]

Q. ARE THERE JURISDICTIONS OUTSIDE OF PJM EXPERIENCING INCREASING GENERATION AND TRANSMISSION COSTS BECAUSE OF RAPID DATA CENTER-DRIVEN DEMAND GROWTH?

A. Yes. In Georgia, Georgia Power increased its estimate of how much new capacity would be needed to serve its loads in 2030 from 400 MW in 2022 to 8,500 MW in 2024.[46] Driven by rapidly increasing demand from data centers, Georgia Power filed a request to the Georgia Public Service Commission ("GPSC") for approval to acquire 9,900 MW of resources at a cost of over $15 billion.[47]

Similarly in Wisconsin, Wisconsin Electric filed an application for approval of a Very Large Customer Tariff and Bespoke Resources Tariff aimed at addressing cost

[45] Mike Jacobs *Policy Brief: Connection Costs,* Union of Concerned Scientists (Sept. 2025), https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf.

[46] *2025 Data Center Fact Sheet,* Georgia Public Service Commission, https://psc.ga.gov/site/downloads/datacenterfactsheet.pdf.

[47] Georgia Power Company's Application for the Certification of the All-Source Capacity Power Purchase Agreements and Company-Owned Proposals, Docket No. 56298, https://psc.ga.gov/search/facts-document/?documentId=223493.

allocation for data centers. The company's investor presentations show it expects to spend $19.3 billion on electric generation over the next five years,[48] a $6 billion increase relative to the five-year plan submitted just a year prior.[49]

Q. HOW ARE STATES RESPONDING TO THE SIGNIFICANT INVESTMENTS REQUIRED TO SERVE DATA CENTER LOAD?

A. Many of the states with significant proposed data center development are moving away from their traditional cost allocation approaches to protect other ratepayers from cost increases and also reduce the risk of stranded assets. While this market is changing quickly, we are increasingly seeing commissions and utilities move to either directly allocate a portion, or all, of the incremental costs of new generation and transmission resources directly to new data center load or develop hybrid approaches, where either a portion of incremental resources is directly allocated to data centers or where data centers are required to pay more than their average embedded costs for generation and transmission resources. These revenues would be used to offset cost increases from data centers for those customers and represent a move away from the state's traditional cost-recovery methodology. In my reading of SB 484, such an approach is required to comply with SB 484 to ensure that large loads are paying the full incremental costs to serve and not shifting costs and risks to other ratepayers.

[48] WEC Energy Group Investor Update: December 2025, at 14. https://s22.q4cdn.com/994559668/files/doc_presentations/2025/Dec/05/12-2025-December-Final.pdf.
[49] WEC Energy Group Investor Update: December 2024, at 13. https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Dec/06/12-2024-December-Final.pdf.

In Wisconsin, Wisconsin Electric proposed that generation and transmission costs be directly allocated to data centers to prevent cost shifting to other customers and reduce the risk of stranded assets.[50]

The Oregon Legislature passed the POWER Act in June 2025, requiring the Oregon PUC to ensure large customers demanding 20 MWs or more of power must sign contracts for at least 10 years and pay for all of the costs they cause, including committing to pay for a minimum amount of energy and the costs of new transmission.[51] Portland Gas and Electric ("PGE") has introduced Schedule 96, approved by the PUC in May 2026 establishing a rate class for large load customers and including protections against cost shifting to other customers: large load customers must pay for 100% of dedicated distribution network upgrades; minimum generation and transmission demand charges are based on 90% of contracted capacity; minimum contract terms are set at 10 years and escalate based on demand, with the largest data centers needing to sign 30 year contracts; and termination fees include the net book value of distribution assets and the greater of remaining transmission and demand charges or three years of minimum transmission and demand charges.[52] The changes resulted in PGE filing a rate case that assigns a 30% increase to large load customers, and lowering residential rates.[53] Similarly, PacifiCorp has proposed a tariff that would

[50] Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs, Docket 6630-TE-113, Final Order (May 21, 2026), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=591873.

[51] Relating to large energy use facilities; and declaring an emergency., House Bill 3546 (Oregon Legislative Assembly – 2025 Regular Session). https://olis.oregonLegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled.

[52] Schedule 96 Adopted with Modifications; Revisions to Schedules 89 and 90 Ordered; Revisions to Rules C and I Ordered; First Partial Stipulation Adopted, Oregon Public Utility Commission, Order No. 26-154, Docket No. UM 2377 (May 7, 2026), https://apps.puc.state.or.us/orders/2026ords/26-154.pdf.

[53] See https://www.kgw.com/article/money/business/pge-raise-rates-data-center-residential-commercial-industrial-power-electric/283-420918fa-4f2f-4f4d-9723-e08ae1245581.

create a new rate schedule for "New Large Energy Use Facilities." The proposal would require large load customers to pay the full cost of infrastructure upgrades needed to serve them.[54]

In Utah, the Legislature passed SB 132, which creates a framework for "large-scale electric service" that includes a tariff for large, flexible loads. The law requires that incremental costs, including generation and transmission costs, are excluded from general rates in order to minimize the potential for cross-subsidization between existing customers and new large load customers.[55]

Arizona Public Service ("APS") recently proposed an updated cost allocation methodology in its ongoing rate case. Their approach allocates incremental generation costs to each customer class based on its contribution to the growth in peak demand.[56] APS proposes to differentiate new generation resources between generation needed to replace retiring resources and generation needed to serve new load growth. To do this, APS will compute the effective load carrying capacity ("ELCC") of retiring assets and subtract that value from the ELCC of any new generation resources. The remaining portion will be treated as serving new load growth, and the cost of all new generation resources will be divided accordingly. APS will continue to allocate new generation costs associated with retiring assets using their traditional embedded cost methods, while generation costs associated with serving new load will be allocated according to

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[54] Re: Advice 25-015—Schedule 401—Service to New Large Energy Use Facilities, Docket UE 463 (October 2, 2025), https://edocs.puc.state.or.us/efdocs/UAA/ue463uaa342299028.pdf.
[55] S.B. 132, Electric Utility Amendments, 2025 General Session State of Utah, https://le.utah.gov/Session/2025/bills/enrolled/SB0132.pdf.
[56] Jamie Moe, Direct Testimony, ACC Docket No. E-01345A-25-0105 at 14:21-27.

the proportion of test year load growth in individual customer classes.[57] In this way, existing customers may be insulated from any cost-shifting due to generation costs caused by growth in large load customers.

In June 2026, FirstEnergy Service Company submitted comments to FERC's Advance Notice of Proposed Rulemaking ("ANOPR") on the interconnection of large loads.[58] FirstEnergy's proposal includes two rate components: current zonal transmission rates to pay for the existing transmission system, and an expansion rate that pays for the network upgrades needed to interconnect new large loads. A data center's obligation for the expansion rate would be reassessed annually as new customers interconnect to the same transmission facilities, ensuring the expansion costs are allocated fairly among the class of customers causing the expansion.[59]

In April 2025, the Pennsylvania PUC held an En Banc Hearing regarding the interconnection of and tariffs for large load customers, and subsequently developed a model tariff based on the comments from more than 50 stakeholders. In its final decision, the Pennsylvania PUC found that the cost of network improvements that would not have been needed "but for" the interconnection of a large load customer

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[57] Moe Direct at 17:13-23.

[58] *Interconnection of Large Loads to the Interstate Transmission System*, Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025) (the Commission issued the ANOPR following a directive from the Secretary of Energy ("Secretary") pursuant to section 203 of the Department of Energy Organization Act); see also the full text of the proposed ANOPR, *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025).

[59] Supplemental Comments of FirstEnergy Service Company, *Interconnection of Large Loads to the Interstate Transmission System,* Docket No. RM26-4-000 (Jun. 5, 2026), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260605-5169&optimized=false&sid=0a8a51cb-1d1c-46c6-9dc9-868f7f952218.

should be allocated to that customer. In such cases, utilities should assess CIAC to recover all distribution and transmission costs needed to connect the new customer.[60]

Public Service Company of Colorado ("Public Service"), in April 2026, proposed a new large load tariff ("Schedule TL") that was designed to ensure large load customers pay *at least* the incremental costs incurred to serve them, with the goal of protecting existing customers from cost shifting. To do this, Public Service will calculate the incremental cost of generation and transmission assets required to serve new large load customers. Then, in a ratemaking proceeding, the company will assess the costs that would be allocated to large load customers under the standard cost allocation framework and allocate to the large load customer class the greater of the incremental or embedded costs. Public Service's "higher of" approach is a clear demonstration that it is not obvious whether incremental or embedded costs are greater for large loads. In addition, large load customers will be required to pay standard rates for other rate components.[61]

Finally, in a contested, non-unanimous settlement agreement with a select number of non-residential customers, FPL introduced a new rate for data centers in its last rate case. The rate includes an IGC which claims to recover incremental generation costs incurred to serve the large load customer.[62] Notably, like DEF, FPL introduced this

[60] Interconnection and Tariffs for Large Load Customers, Docket Number M-2025-3054271, Final Order (May 2026), https://www.puc.pa.gov/pcdocs/1929842.pdf.
[61] *In the Matter of Advice No. 2018 – Electric Filed by Public Service Company of Colardo to Revise Colorado P.U.C. No. 8 – Electric Tariff to Address Large Loads and Add Transmission Large (Schedule TL) and Clean Transition Tariff (Schedule CTT) and Implement Changes to the Transmission Line Extension Policy,* Proceeding No. 26AL-0137E, Direct Testimony of Jeffrey R. Knighten, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_832352.
[62] Order No. PSC-2026-0022-S-EI in Docket No. 20250011-EI, issued January 22, 2026. https://www.floridapsc.com/pscfiles/library/filings/2026/00561-2026/00561-2026.pdf. It is my understanding that this order is not final but was subject to a motion for reconsideration filed on February 6, 2026 (Doc. No.

new rate class in anticipation of new data center customers, but does not have a high concentration of data centers currently.[63]

Across all these states, there is a recognition that data center demand growth is unprecedented, poses new risks, and can expose customers to increased costs in the short run and stranded assets and cost-shifting over the medium-to-long term. Because of this, each of these states has introduced new laws or proposed legislation, regulatory frameworks, or cost allocation approaches aimed at addressing the incremental cost increases that data centers threaten to impose on other customers. DEF has not addressed the fact that all of these jurisdictions are moving away from the embedded cost of service model to avoid cost shifting, in direct opposition to DEF's claims and proposal.

Q. WHAT CAN THIS COMMISSION LEARN FROM RECENT EXPERIENCES IN OTHER JURISDICTIONS?

A. Across both deregulated markets like PJM and vertically integrated markets like Xcel Energy and Wisconsin Energy, areas with significant demand growth from data centers and other large load customers - whether existing or forecast - have experienced increased costs and the increased risk of cost shifting and stranded assets. These jurisdictions are altering their ratemaking practices to address incremental costs with different forms of cost allocation, including direct allocation of costs. Unless the

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00986-2026). Additionally, I am not testifying to reasonableness of the method used to identify incremental generation charges. Any method proposed by DEF should be reviewed and analyzed based on the circumstances at that time.

[63] "Q&A with FPL President on expected data center growth and the company's new customer protections." *FPL Newsroom* (Jan. 2026). https://newsroom.fpl.com/Q-A-with-FPL-President-on-expected-data-center-growth-and-the-companys-new-customer-protections.

Commission puts safeguards in place to protect customers from costs related to building generation and transmission to serve new data center customers, residential and C&I rates could likewise increase in Florida because of cross-subsidies flowing from existing customers to data centers. This cross-subsidization will be in direct conflict with the requirements of SB 484.

C. <u>DATA CENTER LOAD IS UNCERTAIN AND CAN SHIFT COST RECOVERY RISK TO OTHER RATEPAYERS</u>

Q. IS THERE A RISK THAT LARGE LOAD CUSTOMERS' DEMAND FOR ELECTRICITY IS OVERSTATED?

A. Yes, there is. The rapid escalation in demand for training AI models such as ChatGPT has led to significant uncertainty surrounding data centers' future electricity demand. This uncertainty has multiple underlying sources, including uncertain future demand for AI products and potential technological advancements.

Q. PLEASE ELABORATE ON WHAT YOU MEAN BY UNCERTAIN DEMAND FOR AI PRODUCTS.

A. Current forecasts for data center demand are premised on underlying demand for the products that data centers help create: artificial intelligence models like ChatGPT, Claude, and others. However, it is possible that the need for computational power—which requires electricity—is less than expected, either because forecast demand for AI products is overstated or because companies become more efficient at turning electricity into artificial intelligence.

As an example of the former, Sam Altman, the Chief Executive of OpenAI, the company that develops ChatGPT, stated that "Are we in a phase where investors as a whole are overexcited about AI? My opinion is yes," and that some investors may get "very burnt" as projections of future demand moderate.[64] As an example of the latter, in early 2025, DeepSeek, a Chinese competitor to US-based generative AI models like ChatGPT, announced significant reductions in energy consumption following an innovative new approach to designing training algorithms.[65]

Finally, Microsoft announced that it has released Maia 200, "a breakthrough inference accelerator engineered to dramatically improve the economics of AI token generation. … (It) is also the most efficient … with 30% better performance … ."[66] Microsoft's announcement demonstrates at least that (1) technology companies are investing a lot in more efficient chips and (2) the improvements in efficiency are significant leaps, not rounding errors.

Whether because future demand is less than expected, AI developers learn to use energy much more efficiently, or both, the possibility of an AI "bubble" bursting creates the risk that electric generation, transmission, and distribution assets built to serve data centers will become stranded before they are fully depreciated.

Q. YOU SAY THERE IS UNCERTAINTY SURROUNDING FUTURE DEMAND FROM DATA CENTERS, BUT IS THERE ALSO UNCERTAINTY ABOUT

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[64] Beatrice Nolan, *Wall Street isn't worried about an AI bubble. Sam Altman is.*, Fortune (Aug. 19, 2025), https://fortune.com/2025/08/19/wall-street-ai-bubble-sam-altman.

[65] Lauren Laws, *Why DeepSeek Could be Good News for Energy Consumption*, University of Illinois Urbana-Champaign (Feb. 6, 2025), https://grainger.illinois.edu/news/stories/73489.

[66] See https://blogs.microsoft.com/blog/2026/01/26/maia-200-the-ai-accelerator-built-for-inference/.

HOW MANY DATA CENTERS WILL ULTIMATELY BE BUILT AND WHERE?

A. Yes, there is. While there is broad consensus that energy demand from data centers is set to increase rapidly, there is a wide range among those estimates. For example, the International Energy Agency projects global data center demand could double by 2030,[67] a Lawrence Berkeley National Lab study suggests data center load tripling by 2028,[68] and a Deloitte study estimates that U.S. data center capacity could grow from 33 GW in 2024 to 176 GW by 2035.[69]

This uncertainty has been acknowledged by industry participants and data center customers alike. For example, Astrid Atkinson, a former senior director of software engineering at Google, stated that there are "five to 10 times more interconnection requests than data centers actually being built."[70] The president of a shale gas producer has likewise said he expects only 10% of data center projects that have been announced to be built.[71] Similarly, Microsoft, in testimony on Georgia Power Company's 2023 IRP Update, commented "over-forecasting demand from data centers could lead to procuring excessive carbon intensive generation," and recommended that the GPSC only approve near-term resource planning decisions based on "known, mature projects

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[67] *Energy and AI*, International Energy Agency (Apr. 10, 2025), https://iea.blob.core.windows.net/assets/601eaec9-ba91-4623-819b-4ded331ec9e8/EnergyandAI.pdf.

[68] Arman Shehabi, et al., *2024 United States Data Center Energy Usage Report*, Lawrence Berkeley National Laboratory, (Dec. 2024) https://escholarship.org/uc/item/32d6m0d1.

[69] Martin Stansbury et al., *Can US infrastructure Keep Up with the AI Economy?,* Deloitte (June 24, 2025), https://www.deloitte.com/us/en/insights/industry/power-and-utilities/data-center-infrastructure-artificial-intelligence.html.

[70] Brian Martucci, *A Fraction Of Proposed Data Centers Will Get Built. Utilities Are Wising Up*, Utility Dive (May 15, 2025), https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/.

[71] Energy Intelligence, *US Gas Companies Temper Data Center Demand Expectations,* 41 *Natural Gas Week* 11 (Mar. 14, 2025), https://www.energyintel.com/00000195-9503-d464-a7b7-d7bff5ce0000.

that have made firm commitments to Georgia Power."[72] Data center customers have suggested that current forecasts are inaccurate and include double counting issues, speculative loads, and low probability projects.[73]

VI. ALLOCATION OF INCREMENTAL TRANSMISSION COSTS TO COMPLY WITH SB 484

Q. UNDER THE COMPANY'S PROPOSAL, HOW WOULD INCREMENTAL DISTRIBUTION AND TRANSMISSION COSTS CAUSED BY NEW DATA CENTERS BE ALLOCATED?

A. The Company is allocating connection costs through its CIAC policy, and relying on embedded costs rates to recover incremental transmission and generation costs. However, the Company has not conducted any analysis on "but for" connection costs or incremental transmission and generation needs, so there is no verification that the costs caused by large loads are actually being allocated and recovered directly from the responsible large load.

As I have discussed, connection costs can be defined as extremely limited, which include customer-specific assets and only dedicated facilities, to more expansive, such as "but for" upgrades that include all modifications to the system that were caused by the customer. Because SB 484 requires no cost or risk shifting, large load customer connection costs must be considered expansively and include "but for" connection

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[72] Georgia Public Service Commission Docket No. 55378, Microsoft Comments on Georgia Power's 2023 Integrated Resource Plan Update at 1, 4 (Ref # 218199) (Apr. 1, 2024) https://psc.ga.gov/search/facts-document/?documentId=218199.

[73] *Joint Stakeholder Options PJM CIFP-Large Load Additions* at 3, PJM (Oct. 1, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251001/20251001-item-05d---joint-stakeholder-options---amazon-calpine-constellation-google-microsoft-talen.pdf.

costs (which will likely include incremental transmission costs) to fully shield other ratepayers. DEF does not suggest identifying these costs much less recovering them from large loads.

Q. DOES THE COMPANY'S MODIFICATION OF ITS CIAC POLICY COMPLY WITH SB 484'S REQUIREMENT TO PAY CONNECTION AND INCREMENTAL TRANSMISSION COSTS?

No, it does not. The LLCP states that a customer is required to pay 100% of the total estimated cost to extend service in advance. Those payments, less any CIAC, would be refunded to the customer over a period of up to five years.[74] The refund would be handled through the base revenues billed to the customer, with any monies not refunded after five years becoming non-refundable. The Company states that these changes are designed to protect the general body of customers from incurring costs to serve new load if that load does not materialize.[75]

Q. WHAT COSTS ARE INCLUDED IN THOSE THAT MAY BE PAID UP FRONT BY A LARGE LOAD CUSTOMER?

A. It is not clear from the Company's filing, but appears that the CIAC policy only considers site/customer specific costs. While under the Company's tariff these costs may include customer-specific, dedicated substation facilities, the tariff language leave significant discretion to the utility to determine which costs may be covered by a CIAC,

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[74] Legislative Tariff at 9.
[75] Chatelain Direct at 5:19-20.

and outcomes could vary based on engineering configurations.[76] My interpretation of the limited information DEF has provided, is that only costs behind the point of common coupling, on the customer's property side, are recovered through CIAC. When asked in deposition to clarify the CIAC costs recovered, the Company could not provide additional detail.[77] It is extremely concerning that the Company could not provide detail on the connection costs recovered through CIAC as it is required that the large load customers pay for all connection and incremental transmission costs and CIAC is a key mechanism for doing so.[78]

Q. WOULD ANY OF THE CIAC FUNDS NOT BE ELIGIBLE FOR REFUND UNDER THE COMPANY'S PROPOSAL?

A. Part 3 of Section IV of DEF's General Rules and Regulations uses a revenue test to determine whether a CIAC is required. Specifically, the revenue test evaluates the estimated revenue from a customer compared to the costs of its upgrades.[79] If the estimated revenue exceeds the cost by 4 times, the customer is not required to pay a CIAC. The revenue test is applied to several customer types, but applying it to a high load factor, large load customer will almost always result in socializing all connection costs covered under the Company's existing line extension policies.

[76] DEF Response to OPC Interrogatory 48.
[77] Deposition of Matthew Chatelain 33:20-35:6.
[78] Interrogatory 48 also provided vague language associated with assets that could be included within CIAC. Based on the language provided, it is unclear exactly what costs are directly allocated to large load customers. Additionally, the revenue test applied may result in little, to no, costs being included in CIAC.
[79] Section 3.01.

Q. WHAT ARE THE OTHER COSTS TO INTERCONNECT LARGE LOADS THAT WOULD NOT BE INCLUDED IN UNDER THE CIAC POLICY?

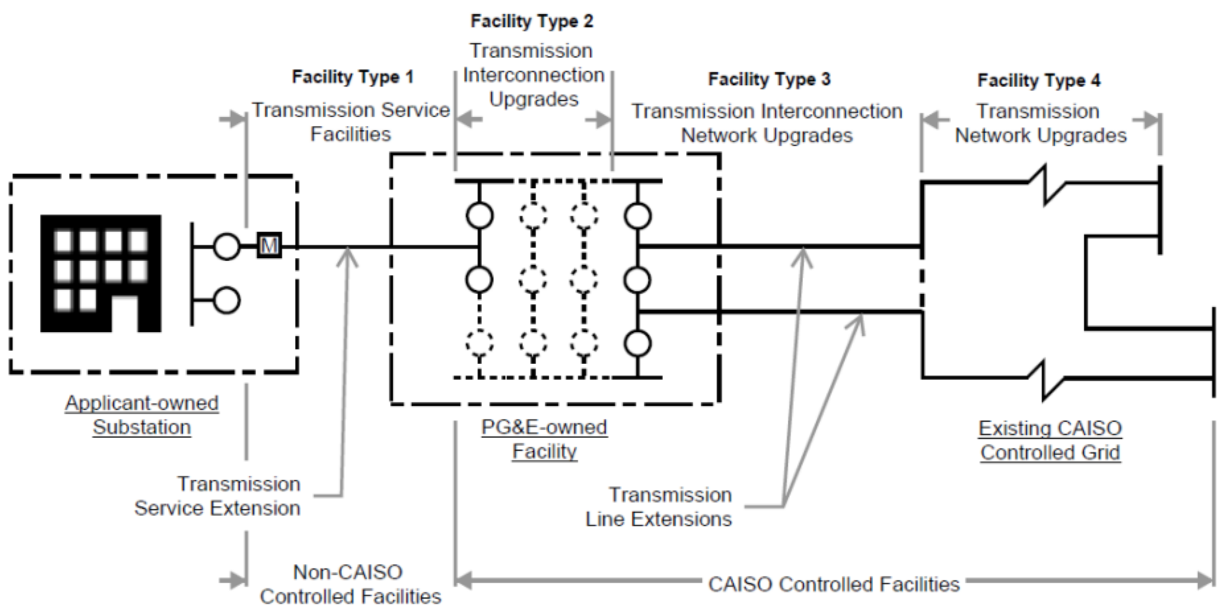
A. The Company's CIAC policy includes an extremely limited amount of connection costs, especially when applied to large load customers. It may not include service lines connecting to offsite substations, off-site substations (even when primarily or solely used by the large load) will not be included, the line from the substation to the bulk transmission system will not be covered, and any network transmission upgrades will not be covered. The CIAC certainly does not cover all upgrades needed "but for" the new customer's interconnection or really any of the system upgrade costs at all. Instead, all of these connection and incremental transmission costs would be socialized among all customers—in direct violation of SB 484. A single substation, for example, can cost between $25-50 million, while network transmission costs can reach into the billions of dollars.[80] The Company has no process of identifying these costs nor allocating them.

Q. HOW WOULD YOU DEFINE THE CONNECTION AND INCREMENTAL TRANSMISSION COSTS FOR LARGE LOAD CUSTOMERS?

A. The upgrades triggered by large loads can be categorized into two types of upgrades: customer-specific, dedicated upgrades, and "but for" upgrades. First, there are dedicated facilities that are built solely to serve one large load customer. These facilities can include customer-specific transmission service lines and/or distribution facilities, dedicated substations, and other incremental transmission and distribution facilities that will only serve the large load. Second, are substations (when not dedicated),

[80] See Nelson Direct in Virginia Docket Nos. PUR-2026-00056 and PUR-2026-00011.

transmission line extension, and network transmission upgrades to shared transmission facilities that may serve many customers, but are still needed "but for" the large load customer. PG&E's Rule 30 includes the following graphic.



The above graphic shows one engineering design. In this case, the large load has a dedicated substation and transmission service facility. These are customer-specific, dedicated facilities in most instances. Then facility types 2 and 3 are a transmission substation and transmission line extensions, that could be dedicated or shared, depending on the circumstances. Facility type 4 is a transmission network upgrade, which is always shared.

Q. HOW SHOULD THE VARIOUS CONNECTION COST TYPES BE ALLOCATED FOR DEF'S LARGE LOADS?

A. I recommend that all customer-specific, dedicated transmission and distribution facilities built to serve large load customers be directly allocated to the customers and paid for through a non-refundable CIAC. These facilities may already be covered by the Company's line extension policy, but would not be contingent on any revenue test within the line extension rule. In the example above, facility types 1 and 2 would be directly allocated through CIAC and nonrefundable.

Q. WHY SHOULD CUSTOMER-SPECIFIC, DEDICATED CONNECTION AND INCREMENTAL TRANSMISSION COSTS BE DIRECTLY ALLOCATED THROUGH CIAC WITHOUT REFUNDING MECHANISM TO LARGE CUSTOMERS?

A. Requiring direct cost allocation of all dedicated transmission and distribution facilities will align with the requirements of SB 484, will help to reduce speculative load by requiring more upfront payments from large load customers, and better reflect cost causation because these facilities will be solely used by the large load customer. It achieves this by removing customer-specific, dedicated facilities from rate base to ensure that other ratepayers will never pay for these assets including if a large load were to terminate service. Similar approaches are being supported by NV Energy's line extension policy, PG&E's Rule 30 proposal, Oregon, and proposed by the PA PUC.[81] Most importantly, directly allocating these dedicated assets to large load customers ensures compliance with SB 484, requiring large loads to pay the full incremental

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81 See https://olis.oregonLegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled. See also https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-rules-north/Rule_09_Electric_North.pdf.

transmission costs to serve them for facilities that will only be used by the large load customer.

Q. HOW SHOULD SHARED TRANSMISSION, INCLUDING SHARED SUBSTATIONS, TRANSMISSION LINE EXTENSIONS, AND NETWORD TRANSMISSION UPGRADE COSTS BE ALLOCATED?

A. These costs should be funded through CIAC with refunds. For example, facility types 2-4 above could be shared, but upgraded due to large loads. Network transmission upgrades present a potentially huge set of costs, as do substations (type 2) and transmission line extensions (type 3) built "but for" the large load customer. To identify network upgrade costs caused by a large load customer, DEF can do modeling with and without large loads to identify which costs are attributable to new large loads. The full cost of any substations, transmission line extensions, and transmission network upgrades caused by a large load or cluster of large loads should be funded up front by large loads to comply with SB 484, with an option to refund over time if the load is maintained.

Q. HOW WOULD YOU DESCRIBE THIS COST RECOVERY APPROACH WITHIN THE FERC FRAMEWORK YOU DISCUSSED ABOVE?

A. I would characterize this approach for dedicated facilities as tradition CIAC and the approach for other upgrades as "higher of" pricing. First, by directly allocating costs that will only serve large loads to the large load customer, DEF will align with cost causation and SB 484. Second, by requiring the large load customer to prepay for all local transmission and transmission network upgrades that are needed for the interconnection of the large load, and allowing the refund of those costs over time, DEF would ensure that a large load customer pays the higher of the embedded and incremental transmission costs it incurs.

Q. WHAT IS YOUR PROPOSED REFUND PERIOD FOR NETWORK TRANSMISSION COSTS PAID FOR BY LARGE LOADS THROUGH A CAIC?

A. Large load customers require significant investments, often ranging from hundreds of millions to billions of dollars for connection and incremental transmission assets. Existing customers would be left paying for these resources if the forecasted load does not materialize. Requiring the costs for network upgrades be paid for in advance is a strong protection for customers because if the forecasted load does not materialize, the large load customers are not refunded and the infrastructure costs are not shifted to other customers. Given the potential scope of costs I recommend customers fund through CIAC, I recommend that the customer be eligible for a refund period of up to 15 years. Any CIAC payment eligible for refund would become non-refundable after this time.

Q. DOES YOUR RECOMMENDATION FOR ALLOCATION OF CONNECTION AND INCREMENTAL TRANSMISSION COSTS COMPLY WITH SB 484?

A. Yes, it does. Under my recommendation, large load customers are required to pay up front for all connection and incremental transmission costs needed to serve them. This complies with the plain language of SB 484 to not shift costs and risks onto other ratepayers.

Q. HOW COULD YOUR PROPOSED CHANGES BE IMPLEMENTED?

A. The Commission could direct DEF to include CIAC specific language into the LLCA, or create an excess facilities charge within the LLCA. Many large load agreements include excess facilities charge when upgrades to the system are distinct compared to status quo upgrades. While DEF did not include an excess facilities term, one could be added to the LLCA using the guidance I provided above.

VII. <u>ALLOCATION OF INCREMENTAL GENERATION COSTS TO COMPLY WITH SB 484</u>

Q. HOW DOES DEF PROPOSE TO ALLOCATE INCREMENTAL GENERATION COSTS IN THIS PROCEEDING?

A. As with other system upgrade costs, it appears that DEF proposes to collect incremental generation costs using its traditional embedded-cost approach. DEF is not proposing to identify or quantify any incremental generation costs caused by large load customers.

Q. DO YOU HAVE CONCERNS WITH THIS COST ALLOCATION APPROACH?

A. Yes, I do. Many of the concerns I have discussed regarding transmission costs that would not be incurred, "but for" a large load, also apply to generation costs. As I discussed above, DEF does not have a sufficient capacity margin to interconnection one 500 MW customer, let alone the over 13 GW it has received inquiries about. Thus, incremental generation will be required to serve new large loads that interconnect to the DEF system.

Q. DOES THE COMPANY'S PROPOSAL FOR ALLOCATING AND RECOVERYING INCREMENTAL GENEATION COSTS COMPLY WITH THE REQUIREMENTS OF SB 484?

A. No, it does not. As I've discussed for other costs, socializing incremental generation costs to all customers will shift costs and risks to other ratepayers and would not be in compliance with SB 484.

Q. WHAT IS YOUR RECOMMENDATION REGARDING ALLOCATION OF INCREMENTAL GENERATION COSTS TO LARGE LOAD CUSTOMERS?

A. As the DEF proposal does not comply with the statute, I recommend that the Commission reject the Company's approach and require it to propose a different cost allocation approach in a future filing where incremental generation costs are directly allocated to large load customers.

Q. WHAT ARE SOME EXAMPLES OF COST ALLOCATION APPROACHES FOR INCREMENTAL GENERATION THAT MAY COMPLY WITH SB 484?

A. An IGC, where large load pays for incremental generation costs and embedded generation costs separately, would comply, assuming the IGC costs are included within the calculation of minimum bills and exit fees. I would also support a similar mechanism to what I recommend for transmission and distribution costs, where the large load customer pays for the full incremental cost upfront through a CIAC payment, with the potential for refund over time. Wisconsin Energy, Xcel Energy Colorado, and FPL have all developed approaches to identifying and allocating incremental generation requirements to large loads.[82] However, any such proposal is complex and will require scrutiny beyond the time required in the instant proceeding. For this reason, the Commission should reject DEF's proposal in full and require a refiled proposal.

Q. DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS RELATED TO INCREMENTAL GENERATION COSTS?

A. Yes. The cost of generation capacity is rapidly increasing. The Commission should ensure that any incremental generation charge includes cost overruns and cost increases incurred through the construction process to ensure these costs are not shifted onto other ratepayers.

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[82] Order No. PSC-2026-0022-S-EI in Docket No. 20250011-EI, issued January 22, 2026. https://www.floridapsc.com/pscfiles/library/filings/2026/00561-2026/00561-2026.pdf. It is my understanding that this order was subject to a motion for reconsideration filed on February 6, 2026 (Doc. No. 00986-2026); *In the Matter of Advice No. 2018 – Electric Filed by Public Service Company of Colardo to Revise Colorado P.U.C. No. 8 – Electric Tariff to Address Large Loads and Add Transmission Large (Schedule TL) and Clean Transition Tariff (Schedule CTT) and Implement Changes to the Transmission Line Extension Policy,* Proceeding No. 26AL-0137E, Direct Testimony of Jeffrey R. Knighten, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_832352;

Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs, Docket 6630-TE-113, Final Order (May 21, 2026), https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=591873.

VIII. <u>LLCP TERMS AND CONDITIONS</u>

Q. ASSUMING THE COMMISSION ADOPTS YOUR RECOMMENDATIONS CONCERNING ALLOCATING CONNECTION AND INCREMENTAL TRANSMISSION AND GENERATION COSTS DO YOU HAVE OTHER RECOMMENDATIONS REGARDING THE LLCP CONSUMER PROTECTIONS?

A. Yes, I do. While the other LLCP terms and conditions have been improved compared to the filing in Docket No. 20250113-EI, there are additional recommendations to increase consumer protections regarding the shifting of costs and risks to other ratepayers. These recommendations assume approval of an approach to allocation of incremental costs for generation and transmission similar to what I propose above. If the Commission does not adopt these recommendations and instead maintains the Company's proposal to allocate costs using average embedded costs, significant additional requirements would be needed to comply with SB 484's requirement to avoid shifting costs and risks to other ratepayers.

A. <u>EARLY TERMINATION FEES</u>

Q. WHAT ARE THE LLCP'S PROVISIONS REGARDING EARLY CONTRACT TERMINATION?

A. The LLCP requires a customer terminating service prior to the end of its contract term to pay a termination fee equivalent to three years of the customer's minimum monthly billing amount, plus the net book value CIAC for new facilities to extend service, less any refundable portion of the upfront CIAC payment which has not yet been refunded.

Customers planning early termination must notify DEF at least two years prior to termination. Customers wishing to terminate the contract prior to achieving full load ramp are responsible for all costs incurred to provide service.[83]

Q. DOES THE LLCP SET PARAMETERS ON WHEN A CUSTOMER MAY REQUEST EARLY TERMINATION?

A. It does not. A customer may request early contract termination at any point during the contract term so long as it gives the Company at least two years of notice; the only consequence of the timing of early termination is the size of the termination payment.

Q. HOW DOES THIS POLICY COMPARE TO EARLY TERMINATION CONDITIONS IN LARGE LOAD TARIFFS RECENTLY APPROVED OR PROPOSED AROUND THE COUNTRY?

A. The early termination conditions proposed in DEF's LLCP are more lenient than most of the recent large load policies I have reviewed. AEP Ohio's proposed large load sub-class is similar to DEF's proposal, with an early exit fee of three years of minimum bills after the first five years of the contract. In Virginia, Rappahannock Electric Cooperative leaves the termination fee open to negotiation within the large load contract in its large load rate sub-class proposal. Every other large load tariff I have reviewed requires an early termination fee of either 1) all minimum monthly bills for the duration of the contract, or 2) the remaining undepreciated value of facilities whose costs have been directly assigned to the customer, whichever is higher. Although DEF's

[83] DEF Rate Schedule, Part XIII, Section 13.05, "Early Termination," pg. 2.

updated LLCP has increased the termination fee to include the net book value of CIAC for new facilities constructed for the large load customer, this provision offers minimal protection to existing customers because only a small subset of incremental costs are included in the CIAC provision, as discussed above. Requiring either an early termination fee equivalent to all minimum monthly bills for the duration of the contract or the remaining undepreciated value of facilities whose costs have been directly allocated to the customer provides more consumer protection than the proposal by the Company, which does not adequately protect DEF's other customers from cost shifting.

Q. HOW DOES AN INSUFFICIENT EARLY TERMINATION FEE CREATE RISK FOR EXISTING DEF CUSTOMERS?

A. When a large load customer terminates service before a utility has recovered the costs incurred to provide that service, the physical grid assets built to serve them remain on the utility's system and in the company's rate base. If the company cannot quickly repurpose those assets, their costs will be socialized to customer groups that do not receive any benefits from them.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION REGARDING THE TERMINATION POLICY IN THE COMPANY'S PROPOSED LLCP?

A. I recommend that the Commission require the Company to amend the early termination section of its LLCP proposal to require customers to pay an early termination fee equal to the monthly minimum bills for the entire duration of their contract term, regardless of which contract year they elect to terminate service early, or the net book value of CIAC facilities for incremental generation or transmission, whichever is greater.

B. <u>SECURITY COLLATERAL</u>

Q. WHAT IS THE COMPANY'S PROPOSAL FOR SECURITY COLLATERAL REQUIREMENTS IN THE LLCP?

A. The LLCP as proposed would require a security amount, in the form of cash or a letter of credit, equal to a percentage of the customer's termination payment obligation. The security percentage would be determined based on the size of the termination payment and the credit rating of the customer. The only firm parameter for the security percentage is that if a customer's termination payment exceeds $100 million, the percentage must be at least 10%.

Q. DOES THE SECURITY COLLATERAL POLICY DO ENOUGH TO PROTECT DEF CUSTOMERS?

A. No. I see two areas for concern with the security policy in the LLCP. First, the language allows far too much case-by-case negotiation with too much discretion by DEF to leave significant costs unsecured based on negotiations with the large load customer; such costs are then at risk of being socialized to the general body of customers. There are few details in the policy, with the only fixed term being the 10% security percentage threshold at an early termination fee of $100 million. Beyond that, the Company can set whatever security percentage it negotiates with the customer, with no input from the Commission, outside stakeholders, or other customer groups. Second, while the policy is light on details, what details are included would result in security collateral amounts too low to protect existing customers from harm. This is partly because the amount is tied to a customer's early termination payment, which is too low under the proposed LLCP, as I explained above. I am also concerned that the negotiated security percentages envisioned in the policy are too low. By setting a low floor of 10% for the security percentage at the $100 million termination fee level, the Company suggests that security percentages for smaller customers could be even lower.

Q. HOW DOES THE COMPANY'S SECURITY COLLATERAL PROPOSAL COMPARE TO OTHER RECENT LARGE LOAD TARIFFS?

A. Compared to the suite of early termination fee policies discussed above, there is a broader range of security collateral provisions in recent large load tariffs. Four of the utilities I have surveyed have weaker terms than the Company's proposal in that they do not specify a collateral requirement or leave it entirely to the utility's discretion: Ameren Missouri, Wisconsin Electric Power Company, Consumer's Energy in Michigan, and Rappahannock Electric Cooperative in Virginia. However, the utilities that do have specific security policies have significantly higher requirements, ranging at the low end from three months of estimated bills up to 50% of minimum charges for the entire contract term, with the most common policy requiring a cash deposit or letter of credit equivalent to two years of monthly bills.[84]

[84] Public Service Company of Colorado requires three months of estimated bills; Appalachian, Indiana Michigan Power Company, and Evergy Kansas and Missouri require 24 months of either minimum or maximum bills; Dominion requires $1.5 million per MW of capacity; AEP Ohio requires 50% of remaining minimum charges; Portland General Electric requires a deposit plus a letter of credit equal to the early exit fee.

Q. WHAT RECOMMENDATIONS DO YOU HAVE TO REMEDY THE SHORTCOMINGS OF THE PROPOSED SECURITY COLLATERAL REQUIREMENT POLICY?

A. To protect existing DEF customers, the LLCP should have more specific parameters for security collateral, and those parameters should result in higher security requirements than the policy currently envisions. While I understand the Company's desire to maintain some flexibility in negotiating collateral amounts for specific customers, the initial parameters for negotiation need to be well defined and much higher. I recommend the LLCP be amended to require security collateral equal to 24 months of minimum bills, based on a customer's planned peak post-ramp period demand.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does at this time. The fact that I do not address any other particular issues in my testimony or am silent with respect to any portions of DEF's Petition or direct testimony in this proceeding should not be interpreted as an approval of any position taken by DEF.

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Education

MS, Agricultural and Resource Economics
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BA, Environmental Economics
Western Washington University, 2006

Work Experience

Founding Partner, Current Energy Group (May 2024 – Present)

- Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, gas decarbonization, and DER integration and compensation.
- Designing and implementing policies and programs to decarbonize energy systems including deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.

Founder, Volt-Watt Consulting LLC (2024 – Present)

Senior Director, Strategen Consulting, (2018 –February 2024)

- Expert witness and advisor that has testified across 20 states in over 80 proceedings and supported multiple state commissions in various proceedings

Economist, Minnesota Attorney General's Office (2013-2017)

- Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models.
- Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO.
- Reviewed and made recommendation to improve gas company pipeline replacement programs, demand response tariffs, performance metrics, and rate designs

Graduate Research Associate, Colorado State University (2011-2013)

Select Publications

DER Integration Framework: Regulatory Innovation for DER Compensation and Cost Allocation. McDonnell, Nelson, and Mims Frick. January 2025. Lawrence Berkeley National Laboratory.
Report

Demand Charges in the Electricity Sector. Speetles, LeBel, Nelson, Zimny-Schmitt, Stright, and McLaren. Funded by the DOE: Office of Electricity. Forthcoming

"A Regulator's Blueprint for 21st Century Has Utility Planning," A Report for Advanced Energy United (2023)
Report
Led the development of a report that provided a blueprint for state public utility commissions that are interested in developing gas utility planning requirements to improve transparency into gas utility resource and capital investment plans.

Nonpipeline Alternative Analysis Framework for the Colorado Public Utilities Commission on Behalf of Lawrence Berkeley National Laboratory (2023)
Report, Report
Through a collaboration with Lawrence Berkeley National Laboratory and the Colorado Public Utilities Commission, led the development of two reports that first examined the existing regulatory approaches for non-pipeline alternatives, and then proposed a regulatory framework.

Consumers Energy Gas Bill Impact Analysis: A Case Study of the Effects of Planned Capital Expenditures and Electrification Trends on Behalf of Advanced Energy United (2023)
White Paper
Quantified the impact of gas utility capital improvement projects on customer rates Consumers Energy gas in Michigan. The paper found that Michigan residential customers with Consumers Energy can expect to see their gas bills steadily increase over the next decade – up to 49% over 2021 levels – due to projected utility capital expenditures and electrification trends.

Select Projects

Worked with Green Mountain Power to develop their Embedded Cost of Service Model. Case No. 25-1955-PET.

Represent Maryland OPC in PC44 DSP and Interconnection Working Groups. 2022-Present. The DSP has been working on a process for stakeholder engagement and review of Maryland utilities distribution system planning processes. The interconnection has designed and implemented a new DER cost allocation approach called the Maryland Cost Allocation Mechanism (MCAM). The ultimately adopted MCAM was designed by Ron and prices hosting capacity by location and scarcity.

GridLab CHARGED Initiative - Flexible Connections, DER Planning, and Advance Rate Design Working Groups – Represent clients in Minnesota, Massachusetts, and Illinois in interconnection, flexible interconnection, interagency rates working group, long term system planning processes, and proactive planning processes. 2021-Present

Maine's Governor's Energy Office: Working in collaboration with Central Maine Power to design and implement non-firm import and export tariffs. 2024

Puerto Rico Energy Bureau – Facilitator and presenter for the Smart Inverter Implementation Working Group. Case No. NEPR-MI-2019-0009. 2024-Present

Puerto Rico Energy Bureau – Support on various regulatory matters. 2024-Present

Hawaii Public Utilities Commission: Advanced Rate Design Proceeding. Docket No. 201-90323. 2020-2021. Documents available here.

Hawaii Public Utilities Commission -Consulted on PBR, rate design, community solar gardens program design, and DER integration. 2018-2024

Kentucky Public Service Commission – Trained staff on cost of service, rate design, distribution system planning, and DER integration. Supported the Commission on all Net Energy Metering Dockets from 2020-2024.

Minnesota Valley Electric Cooperative. Supported on power supply and advanced rate design roadmap. 2023

Xcel C&I Rate Design. Ron used the cost duration model and other embedded cost results to inform a C&I critical peak pricing rate proposal on behalf of Fresh Energy. The MN PUC eventually required Xcel to pilot Ron's proposal across 100s of its customers.
MPUC Docket No. E002/M-20-86

California Energy Storage Alliance. Supported CESA in the SCE Wholesale Distribution Access Tariff Proceeding at FERC. 2019

Expert Testimony

98. Application of Virginia Electric and Power Company For Approval of a Rate Adjustment Clause Rider T-1. Docket No. PUR-2026-00056
Large Load Cost Allocation

97. Application of Virginia Electric and Power Company For Approval of its Large-Load Connection Queue Process Standards. Docket No. PUR-2026-00011. On Behalf of Sierra Club.
Large Load Queue Process

96. Maryland Office of People's Counsel v. PJM Interconnection, LLC. On Behalf of Maryland OPC.
PJM Large Load Cost Allocation
Affidavit

95. ComEd's Petition for Approval of Multi-Year Integrated Grid Plan pursuant to 220 ILCS 5/16-105.17. Docket No. 26-0047. On Behalf of Illinois Citizens Utility Board.
Large Investments and Cost Allocation, Hosting Capacity and Interconnection Investments

94. Illinois-American Water Company. Proposed Rate Increase for Water and Sewer Services. Docket No. 26-0127. On Behalf of Illinois Citizens Utility Board.
Cost of Service, Rate Design, and Rate Riders

93. In the matter of the application of Arizona Public Service Commission for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. Docket No. E-01345A-25-0105. On Behalf of Western Resource Advocates.
Formula Rates
Direct

92. In re: Petition for a limited proceeding to approve large load tariff by Duke Energy Florida, LLC. Docket No. 20250113-EI. On Behalf of the Florida Office of Public Counsel.
Large Load Tariffs, Flexible Connection, and Cost Allocation

91. Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs. Docket No. 6630-TE-113. On Behalf of Walnut Way Conservation Corp.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

90. Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation. Docket No. R-2025-3057164. On Behalf of Environmental Intervenors.
Large Load Tariffs, Flexible Connection, and Cost Allocation

89. In the Matter of Application of Duke Energy Carolinas, LLC Authority to Adjust and Increase its Electric Rates and Charges. Docket No. 2025-172-E. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct Surrebuttal

88. In the Matter of Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges. Docket No. 2025-154-E. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct Surrebuttal

87. Application of Appalachian Power Company for approval of Revisions to the Terms and Conditions of Rate Schedules L.P.S.. Case No. PUR-2025-00057. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

86. Commonwealth Edison Company. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act. Docket No. 25-0514. On Behalf of the Joint Non-Governmental Organizations.
Performance Metrics
Direct Rebuttal

85. Application of Virginia Electric & Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to Virginia Code 56-585.1. Case No. PUR-2025-00058. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

85. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of the Company's Monson-Palmer-Longmeadow (Northwest) Capital Investment Project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U. 20-75-B (2021). Case No. D.P.U 25-31. On Behalf of The Office of the Attorney General.
Distribution System Planning, Interconnection, DER Integration
Direct

84. Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, Docket No. 25-02016. On Behalf of Western Resource Advocates.
Embedded and Marginal Cost of Service, Large Load Line Extensions and Cost Allocation
Direct

83. Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Case 25-E-0072. On behalf of the Environmental Defense Fund.
Rate Design
Direct

83. Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan. Docket No. P-2024-3049223. On Behalf of the Pennsylvania Office of Consumer Advocate.
DERMS, DER Cost Allocation, DERMS Alternatives, Cost-Benefit Analysis

CURRENT ENERGY GROUP

82, In the Matter of the Application of the Yankee Gas Services Company d/b/a Eversource Energy to Amend Its Rate Schedules. Docket No. 24-12-01. On Behalf of the Connecticut State Office of Consumer Advocate.
Rate Design and Cost of Service
Direct Surrebuttal

81. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates. Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates. On Behalf of the Massachusetts AGO (with Andy Eiden).
EV TOU Rate Design, Submetering
Direct

80. In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations. On Behalf of the Utah Office of Consumer Services.
Embedded Cost of Service Study, Flexible Connections, Rate Design
Direct Surrebuttal

79. In the Matter of the Applications of The Dayton Power and Light Company for Approval of Phase 2 of Its Smart Grid Plan and for Approval of Certain Accounting Methods. Case No. 24-0112-EL-GRD. On Behalf of Office of Consumer Counsel.
Grid Modernization Rider Proposal
Direct

78. Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan. Docket No. R-2024 -3049223. On Behalf of PA OCA.
DERMS Implementation, Flexible Interconnection, Export Tariffs, Smart Inverters
Direct

77. Pennsylvania Public Utility Commission v. PECO Gas Company – Electric Division. Docket No. R-2024-03046932. On Behalf of PA OCA.
Weather Normalization Adjustment

76. Pennsylvania Public Utility Commission v. PECO Energy Company – Electric Division. Docket No. R-2024-3046931. On Behalf of PA OCA.
EV Program Design and Load Management

75. Southern Maryland Electric Cooperative, INC's Application for adjustment to Its retail rates and changes for electric distribution service and other tariff revisions. On Behalf of Maryland OPC.
Cost of Service, Rate Design
Direct Rebuttal

CURRENT ENERGY GROUP

74. Order Requiring Ameren Illinois Company to Refile an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. May 13, 2024. Docket No. 22-0487. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Marginal Cost of Service, Proactive Hosting Capacity
Direct

73. Order Requiring Commonwealth Edison Company to Refile an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. May 22, 2023. Docket No. 22-0486. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Marginal Cost of Service, Proactive Hosting Capacity, Peak Load Reduction Programs
Direct Rebuttal

72. PJM Interconnection, L.L.C., Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades (Jan. 10, 2024), Docket No. ER24-843, Accession No. 20240110-5117. Affidavit on behalf of Maryland OPC
Transmission Planning and Cost Allocation
Affidavit

71. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to F.L. c. 164 for approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-based Ratemaking Plan. DPU 23-150.
Cost of service and Rate Design
Direct

70. Easton Utilities Commission's Application for Authority to Increase Its Rates and Charges for Electric Service and Gas Service. On behalf of Maryland OPC. Case No. 9719.
Cost of service and Rate Design
Direct

69. In the Matter of the Tariff Revisions Designated as TA544-8 Filed by Chugach Electric Association, INC. U-23-047. On behalf of AARP.
Cost of service and Rate Design
Direct

68. Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-12, Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-11, Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-10. On behalf of the MA AGO
Grid Planning and DER Integration

Direct

67. In the Matter of the Application of Potomac Electric Power Company for and Electric Multi-Year Plan for the Distribution of Electric Energy Case No. 9702. On behalf of Maryland OPC.
Electric Rate Design and Forecasting
Direct

66. In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, files pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers. On behalf of SWEEP.
Electric TOU Rate Design
Testimony

65. In the Matter of Advice No. 1923 – Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reset the General Rate Schedule Adjustments, to Place into Effect Revised Base Rates, and to Implement Other Phase II Tariff Proposals to Become Effective June 15, 2023. On behalf of WRA.
Electric TOU Rate Design
Testimony

64. Application of Baltimore Gas and Electric Company for a Second Electric and Gas Multi-Year Plan Case No. 9692. On behalf of Maryland OPC
Electric and Gas Rate Design, Gas Transition, Bill Impacts
Direct

63. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: D.P.U. 22-170, 23-06, 23-09, and 23-12 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

62. Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. Docket No. 22-0486. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Hosting Capacity, Value of DER, Peak Load Reduction, Flexible Interconnection, DERMS
Direct

61. Ameren Illinois Company. Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service. Docket No. 23-0067. On Behalf of Environmental Law and Policy Center, Environmental Defense Fund, Natural Resources Defense Council, Illinois State Public Interest Research Group, Inc.
Gas Transition, Capital Planning, Line Extensions, Non-Pipeline Alternatives, Bill Impacts, Gas System Planning, PBR, Rate Design

Direct Rebuttal

60. Pennsylvania Public Utility Commission V. Philadelphia Gas Works. Docket No. P-2022-3034264. On Behalf of The Office of Consumer Advocate
Weather Normalization Adjustment and Decoupling

59. DEP and DEC EVSE Program. Docket No. 2022-158-E. On Behalf of The South Carolina Office of Regulatory Staff
EV Program Design
Direct | Surrebuttal

58. Petition of Philadelphia Gas Works for Approval on Less than Statutory Notice of Tariff Supplement Revising Weather Normalization Adjustment. Docket No. 2022-3034264. On Behalf of the Office of the Consumer Advocate
Weather Normalization Adjustment

57. In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance Based Regulation. Docket No. E-2, Sub 1300. On Behalf of the North Carolina Attorney General's Office
Cost of Service, Rate Design, Performance-Based Regulation
Direct

56. Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations, and Conditions of Service for Electric Service in the State of Oklahoma and to Approve a Formula Based Rate Proposal . On Behalf of AARP
Cost of Service and Rate Design
Responsive Testimony

55. Montana-Dakota Utilities Co. 2022 Electric Rate Increase Application. On Behalf of AARP
Cost of Service and Rate Design
Direct | Surrebuttal

54. Northern Indiana Public Service Company Rate Case. On Behalf of Citizens Action Coalition
Cost of Service and Rate Design
Direct

53. Central Maine Power Company: Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. Section 307, Docket 2022-00152, On Behalf of the Governor's Energy Office w/Panelists Caroline Palmer and Nikhil Balakumar. On Behalf of the Governor's Energy Office
Marginal Cost of Service, Performance-Based Regulation, Distribution System Planning
Direct

52. Georgia Power Company's 2022 Rate Case. DOCKET NO.: 44280. On Behalf of Americans for Affordable and Clean Energy
Electric Vehicle Rate Design
Direct

51. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Citizen's Utility Board of Minnesota
Rate Riders, Fuel Clause Risk Sharing, and MYRP Structure
Direct | Rebuttal

50. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Clean Energy Organizations
Advanced Rate Design, Regulatory Sandbox, TOU Rate Design
Direct | Surrebuttal

49. NSTAR Electric Company d/b/a Eversource Energy, Capital Investment Project Filing: D.P.U. 22-51 through 55 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

48. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: Shutesbury (D.P.U. 22-61) On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct

47. In the Matter of Delmarva Power and Light Company's Application for an Electric Multi-Year Plan (Case No. 9681) On Behalf of the Office of People's Counsel w/ Panelist Jorge Camacho
Distribution System Planning, Capital Investment Plan, Multi-Year Rate Plan Structure, Revenue Decoupling
Direct (No. 21) | Rebuttal (No. 23)

46. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021) (D.P.U. 22-47) On Behalf of the MA AGO w/ Panelists Jorge Camacho, Eli Asher, and Fred Schaefer
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

45. Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. (Docket No.

CURRENT ENERGY GROUP

22-0432 and 22-0442) On Behalf of NRDC, Sierra Club, EDF, RHA and Little Village Environmental Justice Organization (LVEJO)
Electric Vehicle Rate Design and Energy Management Systems

44. Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act (Docket No. 22-0431 and 22-0443) On Behalf of NRDC, Sierra Club, EDF, and RHA
Electric Vehicle Rate Design and Energy Management Systems

43. In the Matter of the Application of a Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma
Cost of service, rate design, formula rate plan
Direct | Stipulation

42. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Commonwealth Edison Company, Docket No. 22-0067 On Behalf of NRDC
Demand Response and Electric Vehicle Performance Metrics
Direct | Rebuttal

41. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Ameren Illinois Company, Docket No. 22-0063 On Behalf of NRDC
Demand Response and Electric Vehicle Performance Metrics
Direct | Rebuttal

40. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC
Performance-based regulation and gas decarbonization
Direct

39. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021)
DER integration, Flexible interconnection, Capital Investment Project
Direct | Surrebuttal

38. In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma
Cost of service, rate design, formula rate plan
Direct | Stipulation

37. In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota. Docket No. E-015/GR-21-335. On Behalf of CUB Minnesota

Cost recovery, cost of service, and revenue apportionment
Direct | Surrebuttal

36. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC
Performance-based regulation and gas decarbonization
Direct

35. Phase 2: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

34. Phase 2: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

33. Phase 2: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

32. Phase 1: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

31. Phase 1: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

30. Phase 1: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative

Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

29. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota
Prudency Review
Direct

28. In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota (Docket No. 21-435) On Behalf of the Clean Energy Organizations
Rate Design and Line Extension Policy
Direct

27. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota
Prudency Review
Direct

26. Green Mountain Power (DKT: 2021-3707-PET) On Behalf of Green Mountain Power
Multi-Year Rate Plan
Prefiled Direct Testimony

25. Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP
ECOSS and Rate Design
Responsive Testimony

24. Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

23. PECO (DKT: R-2021-3024601) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct (note: please type in the docket number, the testimony cannot be directly referenced)

22. Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services
Embedded COS, Rate Design, and AMI Rollout
Direct

21. Minnesota Power* On Behalf of the MN CUB
ECOSS and low-income rate design

20. Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA
DER integration
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

19. Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA
Embedded and marginal COS, Rate Design, and PBR
Direct

18. Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA
Marginal COS, Rate Design, decoupling and PBR
Direct *Settled before direct was filed

17. Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP
Rate Design and CCOSS
Direct

16. Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center
CCOSS and Rate Design
Direct | Supplemental | Case link

15. Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

14. Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case file

13. Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP
Formula Rates, Performance Metrics, Rate Design, and CCOSS
Direct

12. Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP
CCOSS and Revenue Apportionment
Responsive | Case link

11. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

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10. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

9. Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG
Marginal and Embedded CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Case link

8. Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG
CCOSS, Rate Design, and Performance-Based Regulation
Direct | Rebuttal | Surrebuttal |Case link

7. Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG
CCOSS and Rate Design
Direct : | Rebuttal | Surrebuttal | Case link

6. CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG
CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Surrebuttal | Case link

5. Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal | Case link

4. Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal: Case Link

3. Xcel Energy, Minnesota Energy Resources Corp, CenterPoint Energy (DKT: 21-138)
Natural Gas Prudence Testimony
Case Details | Direct

2. Minnesota Energy Resources Corp. (DKT: G-011/GR-13-617) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

1. CenterPoint Energy (DKT: G-008/GR-13-316) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Duke Energy Florida, LLC, for a limited proceeding to approve large load tariff	Docket No. 20250113-EI Dated: February 10, 2026

DUKE ENERGY FLORIDA, LLC'S RESPONSE
TO CITIZENS' SECOND SET OF INTERROGATORIES (NOS. 24-36)

Duke Energy Florida, LLC, ("DEF") hereby responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC"), Second Set of Interrogatories to DEF (Nos. 24-36) as follows:

INTERROGATORIES

For the following interrogatories please refer to DEF's proposed Large Load Customer Policy:

24. Refer to DEF Witness Yager's Direct Testimony at 5:5-13.

a. Explain how the hypothetical sales, load factor, and 12-CP demand assumptions for the LLC rate class were developed. Provide any workpapers used in developing these assumptions in an unlocked Excel workbook with formulas intact.

b. Did DEF perform any modeling of annual hourly load for potential LLC rate class customers? Please provide any 8,760 hourly annual load projections used in such an analysis in an unlocked Excel workbook with formulas intact.

c. Provide a list of prospective data center or other applicable large-load customers currently in any stage of project development within DEF's service territory. This list should include, to the extent information is available:

i. Line of business (e.g. data center, hyper-scaler, AI training, etc.)

ii. Requested capacity requirements

iii. Expected load and capacity utilization ratios

iv. Nameplate capacity, fuel type, and number of onsite generators

v. Service delivery voltage

vi. Stage of development (e.g. submitted capacity request, completed feasibility study, signed electricity supply agreement, enhancement construction in progress, etc.)

vii. Dollar amount and purpose of any contribution in advance of construction

d. Provide a description of current DEF customers under existing rate classes that would be eligible for the proposed LLC-1 class, including:

i. Average billing demand

ii. Annual and 8,760 hourly load

iii. Nameplate capacity, fuel type, and number of onsite generators

iv. Service delivery voltage

e. Provide a description of current DEF customers under existing rate classes that would be covered by the proposed LLCP, including:

i. Average billing demand

ii. Annual and 8,760 hourly load

iii. Nameplate capacity, fuel type, and number of onsite generators

iv. Service delivery voltage

Response:

a. Please refer to DEF's response to question 15, subpart a. of Staff's first set of Interrogatories.

b. Please refer to cells D34 and D35 of attachment Exhibit MJC-1 – Development of LLC-1 Unit Costs.xlsx, provided as a response to #29. These numbers are the kWh sales assumptions from Exhibit KY-1 and a formula that calculates a requisite kW demand billing determinant assuming a consistent 90% load factor, which is in line with expected data center or other applicable large-load customers.

c. Total number of large load projects: **19**
Line of business: **Data center/AI training**
Requested capacity requirements: **13.2 GW**
Expected load and capacity utilization ratios: **80-90% Load Factor**
Nameplate capacity, fuel type, and number of onsite generators: **Unknown at this time**
Service delivery voltage: **230 kV**
Stage of development: **Initial transmission capacity check requested (10), Transmission assessment complete (8)**

Dollar amount and purpose of any contribution in advance of construction: **None requested at this point.**

d. Please refer to DEF's response to question 13 of Staff's first set of Interrogatories.

e. The Company does not currently have any customers that are taking firm service with billing demand of 100 MW or more.

25. Refer to DEF Witness Wishart's Direct Testimony at 23:3-5, and Part XIII of the proposed Large Load Customer Policy, sections 13.02-13.03.

a. What reasoning did DEF use in not placing a limit on a customer's load ramp period?

b. 13.03 states "Minimum Demand shall be between 75% and 85% of annual contract capacity." Under what circumstances would minimum demand be 85% of annual contract capacity, and what circumstances would cause it to be 75% of annual contract capacity?

Response:

a. The Company wants the customer to provide their actual expected ramp and timelines. A limit could require resource planning that is unrealistically accelerated due to an arbitrary policy limit, whereas maybe if a ramp could be extended, beneficial planning and cost management could be achieved. The agreed upon load ramp in an executed LLCA is a very important element for large load projects.

b. The minimum demand will be specified by the Company at a given point in time and will apply to all customers that sign at that time. It will begin at 75% and the range provides flexibility in the event minimum demand needs to be adjusted, driven by costs that arise from the Company's obligation to serve large load customers.

26. Refer to the proposed LLC-1 tariff, Sheet No. 6.190, "Determination of Billing Demand." This section states "Billing Demand shall not be less than the greater of: (1) 90% of the maximum monthly 30-minute kW demand during the preceding 11 billing months, (2) 75% of the Contract Demand, or (3) 1,000 kW."

a. Using the definition of minimum demand set in section 13.03 of the Large Load Customer Policy, if a customer's minimum demand were 85% of annual contract capacity, would part (2) of the billing demand definition of the LLC-1 tariff be 85% of contract demand?

Response:

In this particular scenario, Minimum Demand would be 85% for that specific customer, per the terms in the LLCA, but the definition of Billing Demand in the LLC-1 rate schedule

AFFIDAVIT

STATE OF FLORIDA

COUNTY OF ORANGE

I hereby certify that on this 27 day of January, 2026, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **MARC HOENSTINE**, who is personally known to me, or provided FL DL as identification, and he acknowledged before me that he provided the answers to interrogatory numbers 24c from CITIZENS' SECOND SET OF INTERROGATORIES (Nos. 24-36) TO DUKE ENERGY FLORIDA, LLC in Docket No. 20250113-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28 day of January, 2026.

Marc Hoenstine

JOSHUA BLADOW
Notary Public - State of Florida
Commission # HH 736117
My Comm. Expires Oct 29, 2029

Notary Public
State of Florida

My Commission Expires:

10/29/29

Virginia Data Center Study

Electric Infrastructure and Customer Rate Impacts

Prepared on behalf of the Virginia Joint Legislative Audit and Review Commission (JLARC)

December 2024

Energy+Environmental Economics

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Acknowledgements and Disclaimers

+ This work was funded by the Virginia Joint Legislative Audit and Review Commission (JLARC). The authors of this study would like to acknowledge the contributions of JLARC staff and staff from the University of Virginia Weldon Cooper Center (WCC), who provided the data center load growth scenarios as well as timely input, data, and perspectives throughout the engagement.

+ The authors would like to also thank the experts interviewed for this work, including representatives from load serving entities (Dominion Energy (Dominion), Northern Virginia Electric Cooperative (NOVEC), Mecklenburg Electric Cooperative (MEC)), and several data center companies (Amazon, Cloud HQ, Compass, Google, Meta, QTS, and Stack) for providing their perspectives and insights data center growth, operations, and cost of service studies.

+ It is important to note that although this analysis does examine system impacts throughout Virginia including within Dominion's service territory and the broader PJM region, this modeling exercise has significant differences in scope and intent from Dominion's Integrated Resource Plan (IRP). The analysis described herein is exploratory in nature and is solely intended to examine the implications of different load growth pathways under different levels of decarbonization ambition in Virginia. This study is not intended to serve the same purpose as an Integrated Resource Planning modeling exercise and should not be interpreted as such nor is it meant to model the PJM market precisely.

+ Our analysis is highly technical and reflects industry best practices and as such may not be as accessible to a general lay audience, but we have endeavored to strike a balance between the detail and transparency needed to precisely describe our analysis and modeling vs. being accessible to a broader, more non-technical audience.

+ Lastly, the analysis presented in this report are solely reflective of E3's views and perspectives in the context of the scope of work; all conclusions and takeaways in this report are our own.

Table of Contents

Abbreviations and Acronyms

Table of Acronyms

CCGT	Combined-cycle gas turbine
COSS	Cost of Service Study
DOM Zone	Dominion Transmission Zone
E3	Energy + Environmental Economics
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ESA	Energy Service Agreement
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
JLARC	Joint Legislative Audit and Review Commission
LDV	Light-duty vehicle
LOLE	Loss-of-load expectation
LMP	Locational Marginal Price
LSE	Load Serving Entity
MDV	Medium-duty vehicle
MEC	Mecklenburg Electric Cooperative
NOVEC	Northern Virginia Electric Cooperative

Table of Acronyms (continued)

OSW	Offshore wind
PJM	PJM Interconnection, L.L.C.
PUC	Public Utilities Commission
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	State Corporation Commission
SMR	Small Modular Reactor
VCEA	Virginia Clean Economy Act
VEPCO	Virginia Electric and Power Company
WCC	Weldon Cooper Center

Executive Summary

Energy+Environmental Economics

About This Report

+ **E3 was engaged by the Joint Legislative Audit & Review Commission (JLARC) in Virginia to examine the impacts of data center growth on the state's electric infrastructure needs and associated costs, as well as the distribution of these costs across customer classes. This report summarizes E3's analysis and findings from this study.**

+ **JLARC conducts program evaluation, policy analysis, and oversight of state agencies on behalf of the Virginia General Assembly. This study is part of a broader set of analyses JLARC conducted on data center growth in the state of Virginia.**

+ **This report summarizes:**
  - The background of the study and E3's scope of work
  - The Virginia data center outlook and load growth projections provided by WCC
  - The grid impact modeling and analysis E3 performed to evaluate the impact of data center load growth on Virginia's electric infrastructure needs and associated costs
  - The rate impact analysis E3 performed to evaluate the current energy cost allocation mechanism used by major utilities in Virginia, potential impact of data center load growth on residential customer rates, and recommended policy enhancements and/or considerations

Who is E3?

Technical & Strategic Consulting specializing in the Energy Transition…

125+ full-time consultants | 30 years of deep expertise | Engineering, Economics, Mathematics, Public Policy…


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E3 Clients

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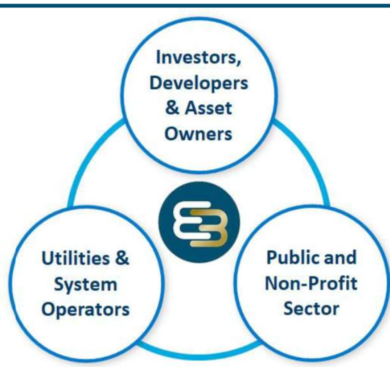


E3 Project Examples

Data center analysis working with utilities, regulators, independent power produces, and data center companies on strategy, siting, rate design, power supply, and grid impacts

Integrated System Planning supporting a wide range of North American utilities with system planning at the distribution and bulk system level across investor-owned and public power utilities

Policy analysis supporting many state regulatory bodies and energy agencies across the U.S.

Market design and expansion analysis working with ISOs/RTOs directly (ERCOT, MISO, AESO, etc.) on design issues including resource adequacy and capacity accreditation as well as analyzing and supporting Western U.S. market expansion between CAISO EDAM and SPP Markets+

Supporting project developers, asset owners, and investors with strategic and market advisory services across **all major power asset classes like renewables, energy storage, gas, transmission, etc.**

Study Background

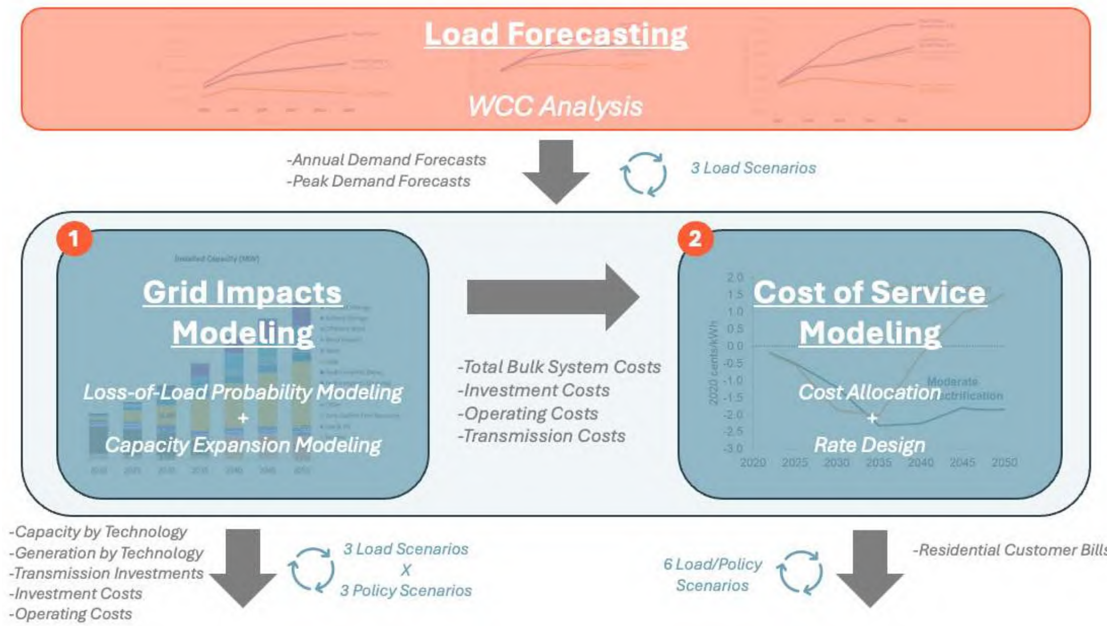
- **Northern Virginia has the highest concentration of data centers globally and remains the fastest-growing market**
  - About 70 percent of **global internet traffic** flows through northern Virginia, according to certain estimates[1]
  - Most facilities are served by Dominion Energy (VEPCO), the state's largest investor-owned utility
- **The recent rapid expansion of the data center industry, which is highly power intensive has driven a significant rise in electricity demand in Virginia**
- **Data center growth is impacting the broader PJM region as well**
  - PJM capacity market auction prices recently hit record highs, due in part to market design changes such as to capacity accreditation and a significant expected increase in energy demand from data centers, combined with supply challenges such as from power plant retirements and congested, slow moving generation interconnection queues
- **In parallel, Virginia is working to achieve an ambitious energy transition**
  - Under the Virginia Clean Economy Act (VCEA) of 2020, investor-owned utilities, such as Dominion Energy, must transition to 100% zero-carbon generation portfolios
  - Dominion and other LSEs are also modernizing an aging grid to achieve multiple objectives one of which is renewable generation integration
- **Given this broader energy landscape, Virginia faces a two-pronged challenge: 1) meeting surging data center growth while 2) also rapidly decarbonizing its electricity supply to meet the goals of the VCEA**
- **E3 has conducted this study to (1) identify the infrastructure investments required to maintain reliability and achieve state policy goals, and (2) to examine current ratemaking and cost allocation practices to assess the associated ratepayer impacts**

[1] Source: https://www.novaregion.org/1598/Data-Centers; https://www.vedp.org/news/dawn-data

Scope of Work and Analytical Framework

- E3 was commissioned by JLARC to examine the impacts of data center growth on electric infrastructure needs and associated costs, as well as the distribution of these costs across customer classes
- Data center growth projections under a Moderate and Unconstrained scenario were provided by WCC as inputs into E3's analysis
- E3 leveraged its in-house electric sector models, RECAP[1] and RESOLVE[2], to identify the least-cost portfolios to meet load growth while also achieving policy goals and maintaining reliability
- Electric sector infrastructure investments were then assessed through a Cost of Service framework to examine existing and modified rate designs and the distributional impacts of these investments under different methods

[1] https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/
[2] https://www.ethree.com/tools/resolve/



The Grid Impacts Modeling included the entire PJM region while focusing on data center load growth projections from WCC for the DOM transmission zone. The Cost of Service assessment then focused on three load-serving entities within the DOM transmission zone (Dominion, Mecklenburg electric co-op (MEC), and Northern Virginia electric co-op (NOVEC)).

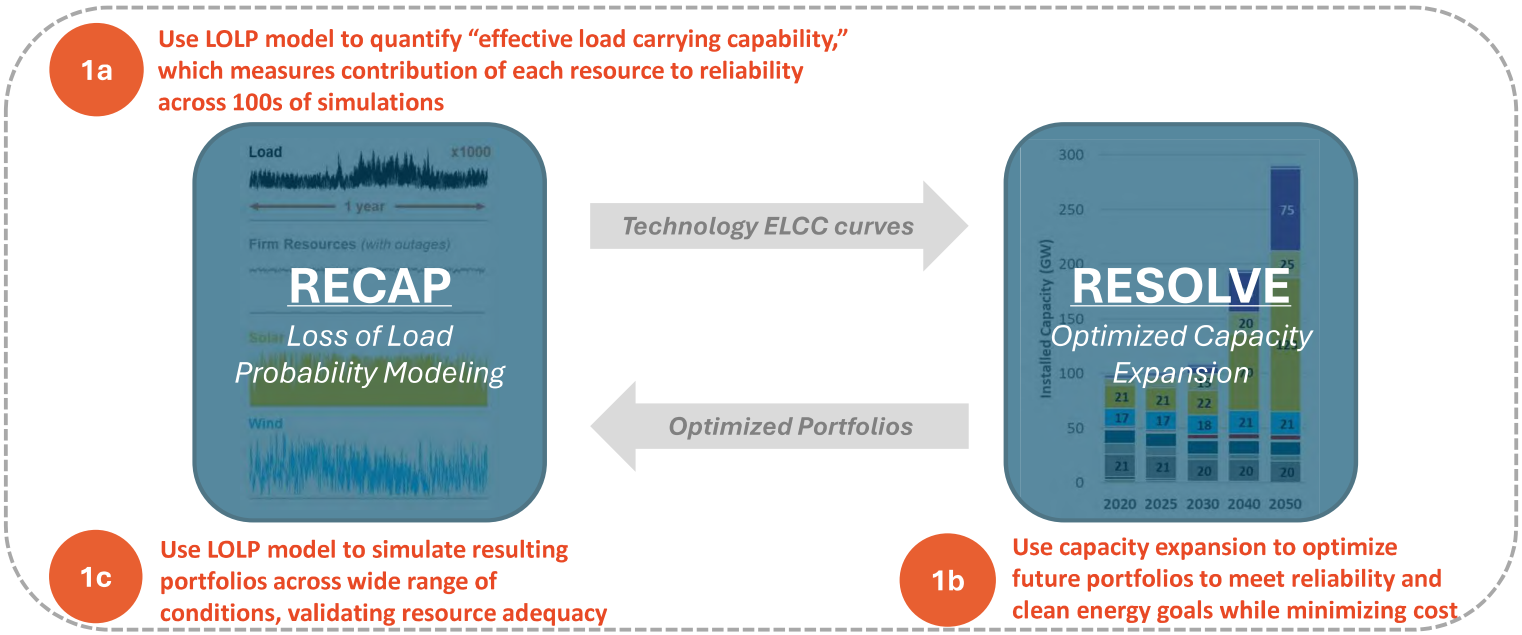
Electric Infrastructure Study Overview

Key Objective of Infrastructure Analysis: Examine electricity system infrastructure and associated investments required to meet the VCEA goals under a wide range of potential data center-driven load growth scenarios

To perform this work, E3 leveraged a ***capacity expansion model*** *in tandem with a* ***loss of load probability model****, in order to ensure the resulting portfolios are reliable over a broad range of weather conditions.*

E3 modeled the entire PJM region within its capacity expansion framework to allow more detailed examination of the interaction between Virginia and the broader market in the context of rapid data center growth. However, by design we did not model the PJM market construct precisely in terms of price formation of energy and capacity prices.

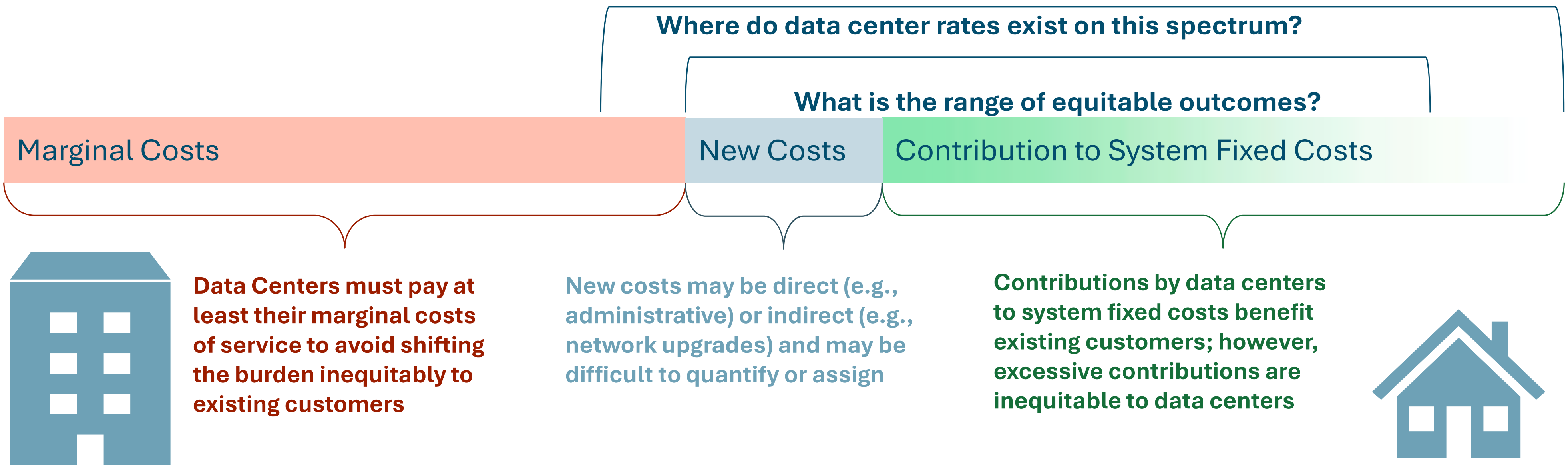
This analytical framework identifies the total infrastructure requirements but does not distinguish between utility-owned infrastructure vs. 3rd party owned vs. "behind-the-meter" generation at data center facilities.



Rate Impact Study Overview

Key Objective of Rate Impact Analysis: Determine if current rate and fee structures lead to an equitable distribution of costs between data centers and other customers

How does the magnitude and pace of data center growth in Virginia influence these cost components?



Scenario Design Considerations

The analytical framework for this study intended to capture key sources of uncertainty along two dimensions:

1. **Load growth uncertainty |** To address uncertainty around how quickly new data center loads can be constructed and interconnected to the system, this study examined three bookends: a counterfactual "No New Data Centers" load projection, a High (Unconstrained) Data Center Growth projection, and a Moderate (half of Unconstrained) projection.
    - The High (Unconstrained) projection assumes that data center facilities can be sited, built, and interconnected as fast as the market desires; in practice, constraints on the pace of infrastructure development may limit how quickly these facilities can add electric demand to the system.
2. **Level of decarbonization ambition |** To address uncertainty around the implementation of Virginia decarbonization policy and facilitate understanding of the impact of current state policy, this study examined three cases: a counterfactual No Policy scenario for each load projection, an IOU-Only VCEA case (consistent with current law), and a Statewide VCEA scenario in which all statewide sales are subject to similar requirements as set forth in the VCEA. Key sources of uncertainty include:
    - **Accelerated Renewable Energy Buyers Program** | The VCEA indicates that commercial or industrial customers are able to purchase their own Renewable Energy Credits from projects within the PJM region, and their sales would be exempt from the VCEA requirements; this would effectively have the impact of lowering the in-state requirements and potentially leading to a shift in resources from Virginia to neighboring PJM states.
        - Data center customers are also exploring the concept of co-location with generating facilities or "bring-your-own-generation"; our electric system infrastructure modeling is focused on the total quantity of infrastructure required in the state, which would not meaningfully change regardless of whether the infrastructure is built by the utility or the data center customer, though it may have implications for cost allocation and ratemaking.
    - **Applicability of VCEA to Electric Cooperatives |** The VCEA only applies to the retail sales of Investor-Owned Utilities (IOUs), and therefore any data centers that choose to purchase their energy from electric co-ops would not be subject to the VCEA requirements. We examined a set of IOU-only VCEA cases (consistent with current law) in which a significant share of new data center loads are met by co-ops which are exempt from the VCEA requirements. However, tech companies that purchase their power from electric co-ops may still have similar levels of decarbonization ambition; as a result, we also examined Statewide VCEA cases which assume that sufficient clean energy is installed to supply all statewide sales with VCEA-compliant electricity, regardless of provider.

Overview of Scenarios and Sensitivities (1/2)

Scenarios for this analysis were constructed to examine the impacts of data centers on the Virginia electric system along two dimensions:

1. **Levels of data center growth**
   - [Counterfactual] No Data Center Growth ("S1" cases)
   - Moderate (half of Unconstrained) Data Center Growth ("S2" cases)
   - Unconstrained Data Center Growth ("S3" cases)
2. **Levels of VCEA achievement**
   - [Counterfactual] No VCEA Compliance ("A" cases)
   - Achievement of VCEA by Investor-Owned Utilities ("B" cases)
     – The VCEA only applies to investor-owned utilities, and electric co-operatives are exempt from the VCEA requirements; in other words, the "B" cases are consistent with current law.*
   - Full Statewide Achievement of VCEA ("C" cases)
     – By 2045 around 62% of the projected data center loads in Virginia are served by co-operatives in WCC's forecast; E3 examined the full statewide achievement cases for better understanding of a potential bookend scenario

All scenarios include current "on-the-books" federal policies, including the Inflation Reduction Act and EPA carbon dioxide regulations, as well as current state policies and targets in the rest of PJM; exploring scenarios incorporating potential changes to currently enacted policies and rules was outside the scope of this study

VCEA Achievement →

Higher Data Center Growth ↓

S1A *No data center growth; non-compliant with VCEA*	**S1B** *No data center growth; IOUs comply with VCEA* *(current requirements)*	**S1C** *No data center growth; all statewide sales meet VCEA* *(beyond current requirements)*
S2A *Moderate data center growth; non-compliant with VCEA*	**S2B** *Moderate data center growth; IOUs comply with VCEA*	**S2C** *Moderate data center growth; all statewide sales meet VCEA*
S3A *Unconstrained data center growth; non-compliant with VCEA*	**S3B** *Unconstrained data center growth; IOUs comply with VCEA*	**S3C** *Unconstrained data center growth; all statewide sales meet VCEA*

*All references to VCEA compliance scenarios in the JLARC Report refer to existing VCEA requirements, or the "B" scenarios. Full statewide achievement of the VCEA in the "C" scenarios is strictly exploratory and only for reference in the E3 Report.

Overview of Scenarios and Sensitivities (2/2)

- **Across all core scenarios analyzed, constraints were implemented within the model to reflect the feasibility of building out new resources in Virginia within a given timeframe, based on historical pace of build, expected constraints on in-state development such as availability of land, and other factors**
  - Under the most aggressive scenario combining unconstrained data center growth with statewide VCEA achievement (**S3C**), which goes beyond current legislated requirements, E3 also examined bookend sensitivities in which specific constraints were relaxed:
    - **High In-State Renewables**: Higher levels of onshore wind available and accelerated deployment of offshore wind allowed in Virginia and North Carolina
    - **Regional Coordination**: Relaxed constraints on transmission build-out post-2035
    - **Nuclear Renaissance**: No constraints on nuclear build-out post-2035 such as on small modular reactors

VCEA Achievement →

Higher Data Center Growth ↓

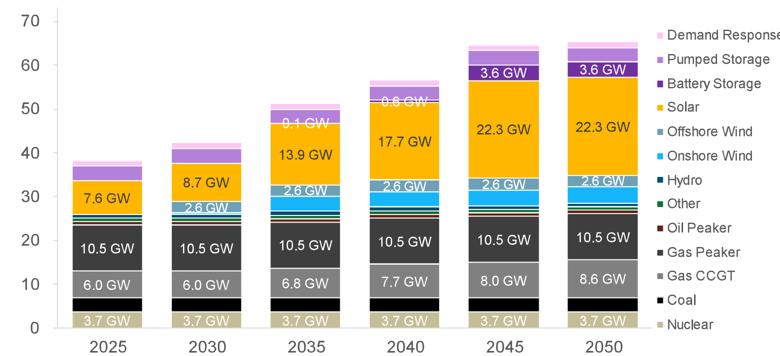
S1A *No data center growth; non-compliant with VCEA*	**S1B** *No data center growth; IOUs comply with VCEA* *(current requirements)*	**S1C** *No data center growth; all statewide sales meet VCEA* *(beyond current requirements)*
S2A *Moderate data center growth; non-compliant with VCEA*	**S2B** *Moderate data center growth; IOUs comply with VCEA*	**S2C** *Moderate data center growth; all statewide sales meet VCEA*
S3A *Unconstrained data center growth; non-compliant with VCEA*	**S3B** *Unconstrained data center growth; IOUs comply with VCEA*	**S3C** *Unconstrained data center growth; all statewide sales meet VCEA*

Key Findings | Electric Infrastructure (1/4)

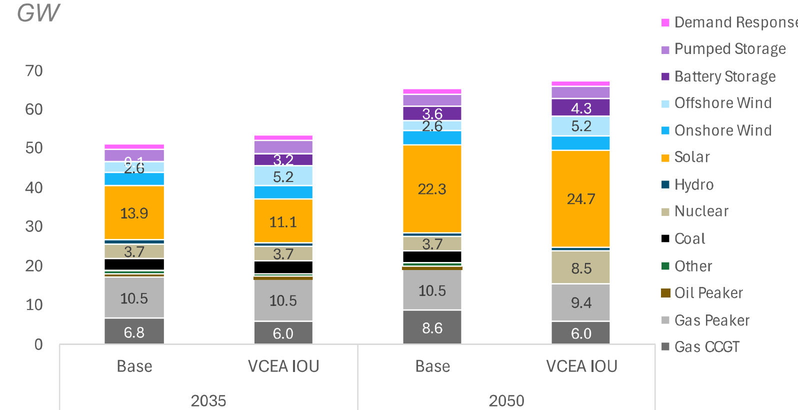
Achievement of VCEA Goals without Data Center Growth

1. **In the No Growth scenario without the VCEA, Virginia is projected to meet new demands through an expansion of solar and battery energy storage capacity, coupled with a moderate increase in natural gas generation capacity to meet reliability needs**
2. **In the No Growth scenario, achievement of the VCEA is projected to drive the development of new nuclear capacity (in the form of SMRs), additional solar builds, as well as conversion of gas facilities to hydrogen to meet system reliability needs**
   1) Incremental investments in renewable capacity driven by the VCEA are moderate and not outsized relative to planned and economic-driven investments
      1) Solar and battery storage are projected to be an economic part of Virginia's portfolio, with or without the VCEA
      2) In the near to medium term, the VCEA technology targets also drive the build-out of additional offshore wind, reducing the state's reliance on natural gas
   2) In the longer term, the VCEA requires the retirement of all carbon-emitting generation by 2045, which leads to a build-out of substantial amounts of nuclear capacity to replace generation from coal and gas, as well as a conversion of gas-fired units to hydrogen to remain online for electric system reliability needs, i.e. maintaining acceptable loss of load probability on a system level

Virginia Installed Capacity (S1A)
GW



Virginia Installed Capacity [1]
GW



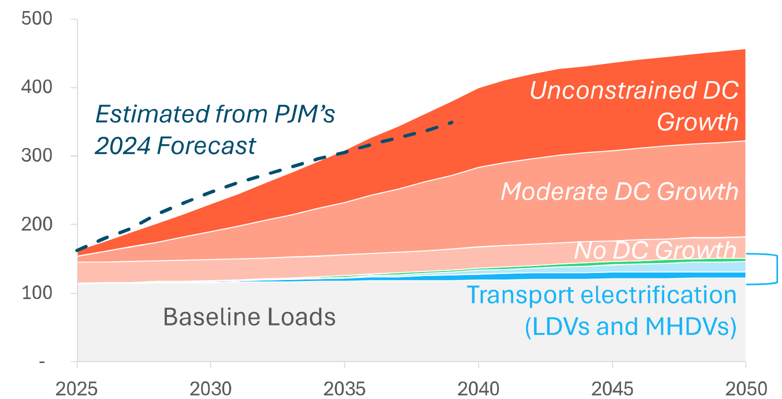
[1] Unless otherwise noted, all gas capacity shown for VCEA cases in 2050 throughout this report represents gas resources that are converted to run hydrogen for compliance with state policy.

Key Findings | Electric Infrastructure (2/4)

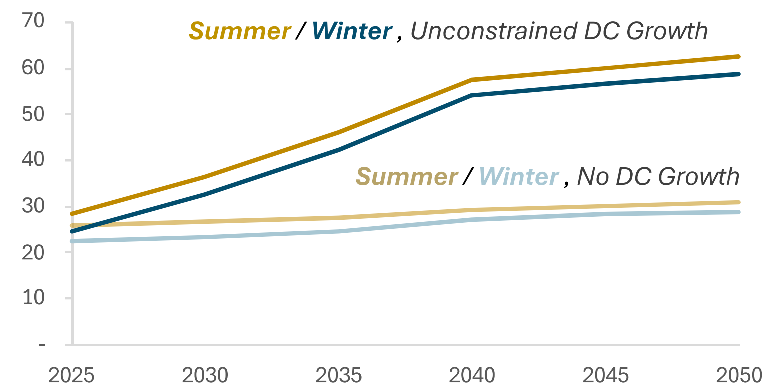
Impacts of Data Center Growth on Total Demand and System Reliability Needs

3. **If current trends continue, data center load growth could lead to as large as a tripling of electric sector demand in Virginia in the Unconstrained Data Center Growth scenarios, relative to today's levels, by 2050**
4. **This level of large and sustained demand growth driven by a single large customer type would be unprecedented in recent U.S. history, and would place significant pressure on system planners' ability to build sufficient generation, transmission, and distribution infrastructure to keep pace**
   1) Peak demand in Virginia could increase to over 60 GW, requiring substantial investments in new infrastructure
   2) While data center computing loads do not vary significantly between seasons or within a day, the sheer volume of data center growth shifts the timing of reliability needs to times when total facility demand is marginally higher due to cooling needs, in the summer afternoons and evenings
   3) The high cooling demand of data centers which typical peak in afternoon summer hours, creates opportunities for synergistic pairings of solar and battery storage although their reliability contributions eventually saturate. Large quantities of firm, dispatchable capacity will also be needed to meet demand growth reliably

Virginia - Annual Load Projection (TWh)



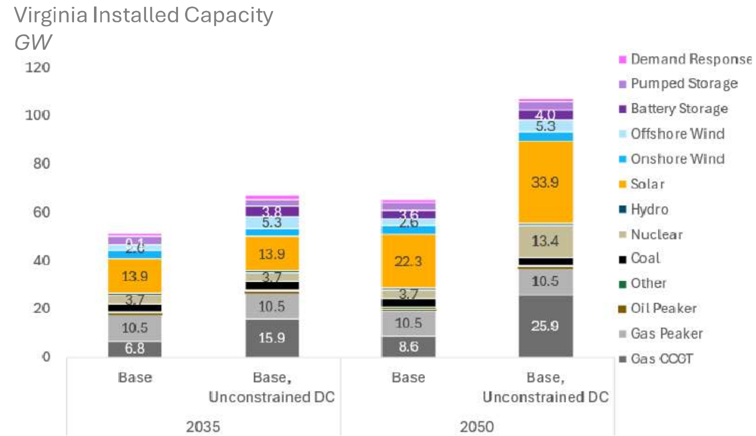
Virginia - System 1-in-2 Peak Projection (GW)

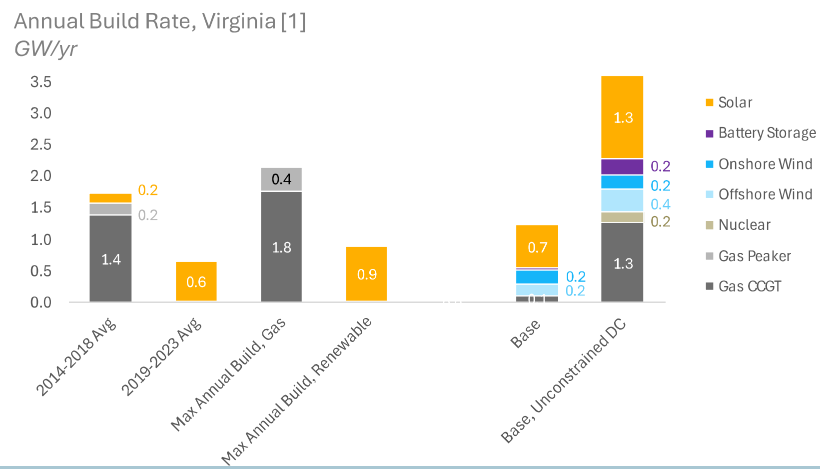


Key Findings | Electric Infrastructure (3/4)

Impacts of Data Center Growth on Electric Infrastructure Needs

5. **In the absence of state policy, data center load growth is projected to drive a build-out of a diverse mix of resources, including gas, solar, nuclear, offshore wind, and battery storage**
6. **Without the VCEA in place, data center growth could lead to a significant increase in the region's reliance on gas generation**
    1) This expansion of gas capacity and generation would also lead to up to an ~80% increase in electric sector GHG emissions in the state; however, current EPA regulations would limit the run-times of new gas units and lead to a significant build-out of low-carbon generation as well, including new nuclear generation to meet baseload energy demands
7. **Meeting demand growth would require sustaining a very high pace of new capacity additions through 2040, including new resources that have not been widely deployed today such as SMRs and offshore wind**
    1) The pace of needed, continual electric infrastructure development is high compared to recent history (3.6 GW/yr needed on average over the next 15 years, compared to a historical single-year high of 2.2 GW/yr)
    2) As a result, infrastructure constraints could act as a constraint on data center growth in the near to medium term



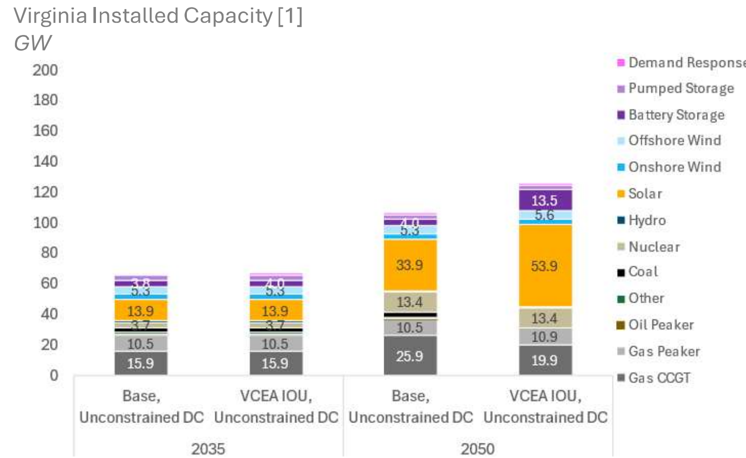


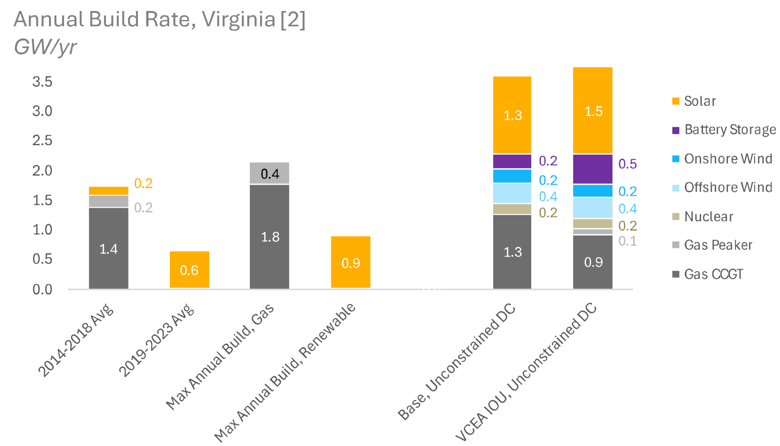
[1] Scenario build rates represent the annual average build rate between 2025-2040.

Key Findings | Electric Infrastructure (4/4)

Achievement of VCEA Goals with Data Center Growth

8. **With the VCEA in place, Virginia would likely require unprecedented investments to accelerate the deployment of both existing and emerging clean energy resources**
   1) Under high levels of data center growth, achievement of the VCEA would drive a sustained acceleration of solar deployment compared to recent history (1.5 GW/yr over the next 15 years, compared to a single-year high of 0.9 GW/yr)
   2) Achievement of the VCEA would also require transformative investments in several long lead-time resources by 2050, including new nuclear capacity (10 GW), hydrogen-capable combustion turbines (31 GW of new builds and retrofits) and associated production and delivery infrastructure, as well as new transmission capacity (8.7 GW) and a significant increase in the state's reliance on market purchases
      1) Building out one of these resources at the scale envisioned under this scenario would be challenging but potentially feasible with a significant investment of time and resources; however, building out each of these resources at this scale in parallel would require a sustained mobilization of capital and planning staff
   3) In total, meeting unconstrained demand growth with clean energy would require a build-out of over 3.8 GW/yr between 2025-2040, including new nuclear, hydrogen, and offshore wind, compared to a single-year high of 2.2 GW/yr





[1] Unless otherwise noted, all gas capacity shown for VCEA cases in 2050 throughout this report represents gas resources that are converted to run hydrogen for compliance with state policy.
[2] Scenario build rates represent the annual average build rate between 2025-2040.

Key Findings | Retail Rate Equity

1. **Current rates appropriately apportion costs to classes and customers responsible for incurring them including large loads like data centers, which means there has been no historic cost shifting based on our analysis**
2. **Load growth is expected to increase system costs in Virginia with some effects directly attributable to new large loads (i.e., data centers)**
3. **Fixed costs associated with generation and transmission are difficult to effectively assign; these represent the largest sources of potential ratepayer inequity with data center growth vs. distribution costs that can be more easily assigned to specific customers**
   1) Generally, specific load interconnection costs (such as at the distribution level) are easily assessed and recovered; likewise, incremental variable costs associated with energy or demand, can also be effectively measured and assigned
   2) Periodic adjustment of retail rate design and cost allocation factors will mitigate some impacts of potential and unintended cross-subsidization between rate classes; however, without frequent and precise adjustments and/or significant rate reform, the cumulative impact of data center load growth is projected to cause cost shifts between ratepayers that may be inequitable
4. **Ultimately, while it is possible to scale the existing, embedded (average cost based on existing infrastructure) rate structure to accommodate data center loads accounting for the marginal costs to serve that new load in a manner that is equitable for existing ratepayers, the cost shifting risk from a variety of sources makes the path to navigate that transition complex and potentially narrow**
   1) One such source of risk, beyond the scope of this study, would be the impacts of the scale of investments (and associated risk of those investments) on utility balance sheets, which has the potential to raise borrowing costs and thus increase costs for existing ratepayers
   2) Adjustments to rate structures can be implemented to reduce risks and improve proper apportioning of costs while still promoting strong economic development and allowing access to potential benefits associated with data center growth; tools to mitigate rate impact might include: Improving frequency of updates for cost allocation factors; assessing additional charges for data centers that further balance costs; improving forecasting of data center demand through features like a waitlist for service that can derisk load attrition; implementation of long-term service commitments that may include more significant minimum charges, ramping provisions, exit fees, and/or contract length; promoting self supply of resources; or more direct assignment of new infrastructure costs as well as increased credit or collateral protection for the utility and its ratepayers

Key Sources of Uncertainty | Infrastructure

Scenario analysis was performed to examine uncertainty surrounding load growth trajectories as well as the impacts of VCEA compliance. However, there are many sources of uncertainty that warrant further exploration that were not examined within this study.

Key sources of uncertainty that would impact the infrastructure findings include but are not limited to:

+ **Magnitude and timing of computing loads |** This study examined two scenarios for future computing load growth provided to E3 by the Weldon Cooper Center at UVA. The study assumed that data center loads in Virginia continue to primarily consist of flat, inflexible/non-interruptible load, due to the attractiveness of low latency infrastructure in Virginia. However, advances in chip efficiency, overall data center design and power usage, and/or ability to utilize on-site or adjacent generation resources could reduce the amount of power that needs to be supplied to data centers. Additionally, some portion of projected data center load may be used for artificial intelligence training, which is expected to be a much more flexible load relative to conventional computing because it may have less stringent latency requirements as well as response time in addition to future AI driven workloads that may also not require stringent latency requirements with flexibility on completion timing.
+ **Federal and regional policy uncertainty |** This study kept demand growth in the rest of the PJM region consistent across scenarios, leveraging PJM's publicly available forecast, e.g. it includes data center load growth across the region. Additionally, the modeling assumed that all states meet their currently legislated policies and do not alter their policy ambition, and that existing federal policies (e.g. Inflation Reduction Act, EPA carbon limits) remain in place. As an interconnected market, any shifts in the overall supply and demand balance in the rest of PJM will impact Virginia's own infrastructure needs and associated costs as well as the overall PJM market prices for energy and capacity along with regional renewable energy credit or environmental attribute prices.
+ **Resource costs |** This study leveraged publicly available cost projections to represent the costs of future technologies, relying primarily on the Annual Technology Baseline "Mid" trajectory published by the National Renewable Energy Laboratory, with adjustments to reflect regional and state-specific costs for materials, labor, etc. The trajectory of future technology costs is uncertain, and that uncertainty grows over time; this study did not explore the sensitivity of results to changes in the future costs of technologies.
+ **Resource availability and pace of deployment |** This study applied near-term constraints that limited the pace of technology additions to historical maxima; after 2035, the model was unconstrained in its build-out of resources (although costs are escalated within a given region as lower-cost sites are exhausted). However, siting, permitting, and interconnection processes are time-intensive and the pace of resource additions may continue to be limited by regional, state, and/or local constraints on development. E3 notes that all new bulk system infrastructure, including nuclear, new natural gas, new renewables, energy storage, and new transmission, each face constraints on their development.
+ **Emerging technologies |** This study assumed that new nuclear power plants, and in the VCEA case, hydrogen-fired combustion plants, would be available after 2035. However, neither of these technologies has been deployed at commercial scale to-date, and if either or both of these resources do not become commercially available, this would alter Virginia's portfolio under each scenario. Each of these technologies also faces even greater cost uncertainty than technologies that are available today given their readiness levels.
+ **Transmission and imports |** Related to policy uncertainty in the rest of PJM, this study assumes that Virginia is able to continue – and in many scenarios, expand – its reliance on imported capacity and energy from the PJM market. If the market is more constrained than projected, Virginia may not be able to expand its trading capabilities across the region.

Key Sources of Uncertainty | Retail Rate Equity

Scenario analysis was performed to examine uncertainty surrounding load growth trajectories as well as the impacts of VCEA compliance; however, there are a number of sources of uncertainty that warrant further exploration that were not examined within this study.

In addition to the sources of uncertainty detailed above for the infrastructure analysis, key sources of uncertainty that would impact the retail rate equity findings include but are not limited to:

+ **Risk of load departures |** There is a fundamental misalignment in the timescales of investments being made in generation and transmission infrastructure relative to the lifetime of data center facilities. Electric infrastructure consists of long lifetime assets (often 30+years) whose costs are allocated to electric ratepayers across many decades. However, data center facilities depreciate quickly, and this presents risks that companies and facilities choose to leave the region or that their demand shrinks considerably, in which case infrastructure would be "overbuilt" and remaining customers on the system – including residential ratepayers – would be required to pay significantly more in order for the utility to recover the costs of its investments.

+ **Impacts on PJM market prices |** Although this study captured Virginia's position within the broader PJM market, the model assumes that the market is able to reach equilibrium in the long run. However, constraints on the pace of infrastructure development, coupled with high levels of data center growth, has the potential to place continued strain on region-wide capacity, energy, and renewable energy credit prices. The resulting market scarcity, and corresponding increases in prices, could place additional pressure on non-data center customers. This may also trigger various market reforms and actions by other market participants that impact price formation in the PJM market which was not analyzed.

+ **Impacts of expenditures on utility balance sheets |** The scale of investments required to meet data center load growth can place significant pressure on an investor owned utility's balance sheet or a public utility's borrowing ability as it brings on more capital to finance these investments. This may in turn lead to increasing costs given the scale of the capital and perceived risk around the utilization and recovery of the costs including a fair return on these infrastructure investments, which could impact all utility ratepayers.

+ **Rate design of utilities not examined in this study |** While this study performed a detailed review of rate design for utilities where major data center development is expected to occur, like NOVEC and Dominion, there may be other utilities in Virginia that manage data center costs and load growth in ways not considered herein including novel structures.

Study Background

Energy+Environmental Economics

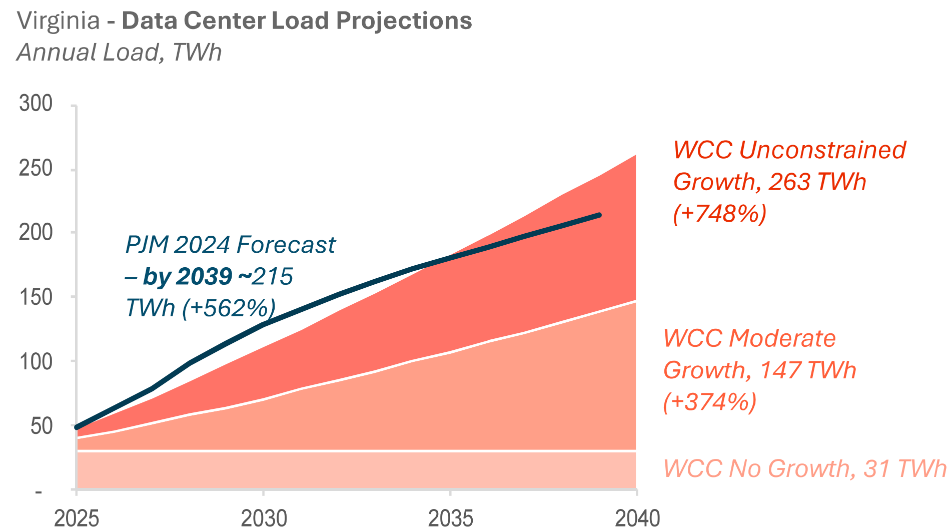
Data Center Growth in Virginia

+ **Northern Virginia has the highest concentration of data centers globally and remains the fastest-growing market**
  - About 70 percent of **global internet traffic** flows through northern Virginia, according to certain estimates[1]
  - Most facilities are served by Dominion Energy, an investor-owned utility that is the state's largest load serving entity (LSE)
  - The rest of the state is a secondary market, with the central and southern regions seeing increasing development, served by Northern Virginia Electric Cooperative (NOVEC) and other non-profit co-ops
+ **The recent boom in data center growth has driven a significant uptick in energy demand in Virginia**
  - Dominion's 2024 IRP highlighted that metered data center demand growth doubled from 2017 to 2020 and again from 2020 to 2024
  - This growth is not expected to subside soon, with Dominion forecasting data center peak demand reaching 9 GW (contributing to a 25% increase above current total system peak) in the next 10 years
  - However, there is significant uncertainty around key variables that could greatly reduce demand forecasts, such as processor efficiency improvements and new technologies such as liquid cooling
+ **Data center growth is impacting the broader PJM region as well**
  - PJM capacity market auction prices recently hit record highs, due in part to a significant increase in energy demand from data centers, combined with supply challenges such as from power plant retirements and congested interconnection queues
  - These increased costs can lead to higher rates for customers across the region, including neighboring states
+ **Geographically, data center demand is and will likely continue to be highly uneven, with data centers tending to cluster, suggesting Virginia will continue to be a major market**

[1] Source: https://www.novaregion.org/1598/Data-Centers; https://www.vedp.org/news/dawn-data

Data Center Growth Scenarios

- **UVA's WCC researches a wide variety of issues and provides data and services to communities, governments and public sector leaders, with particular expertise in Virginia energy markets, policy and demand forecasting**
- **WCC developed load projections for 3 data center growth scenarios**
  - The Unconstrained and No Growth scenarios serving as bookends to illustrate the difference between a sustained unconstrained growth BAU scenario vs. a counterfactual of no growth post 2023
  - The WCC scenario projections focused on data center growth in Virginia, assuming it is all located in the DOM transmission zone (including customers of Dominion, NOVEC, and Rappahannock)
    - The PJM public forecast was used for data centers outside DOM and VA - in AEP, APS, and East – and kept constant across scenarios
  - The WCC "Unconstrained" projections are generally aligned with the public 2024 PJM load forecast
- **WCC also provided load projections for Virginia for baseline loads and vehicle electrification loads by utility, in order to capture the rest of the Commonwealth's system with the same level of detail**

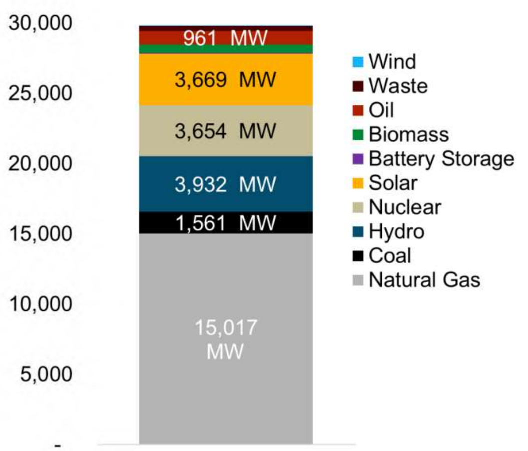


Note: WCC data center growth projections were developed for Virginia, assuming all growth occurs in the DOM transmission zone. Unless otherwise specified, all references to demand and infrastructure build-out in the Dominion area or "DOM Zone" throughout this deck refer to the entire **Dominion transmission zone** within PJM, not just sales and generation provided by the Dominion utility.

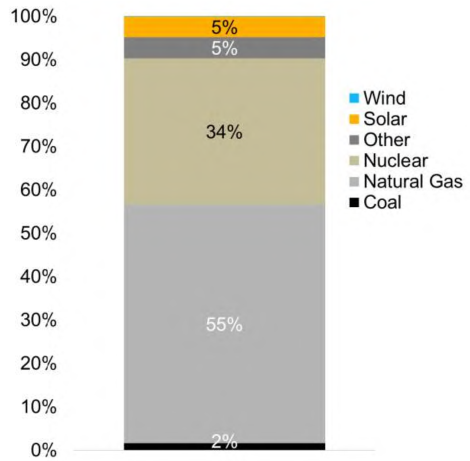
Electric Resource Mix in Virginia | 2023

- Virginia's existing resource mix is largely natural gas, representing 50% of the installed capacity and 55% of in-state generation in 2023
- Nuclear was the second largest segment representing 12% of installed capacity and 34% of generation in 2023
- While renewables are only a minority of Virginia's existing resource mix, solar and storage makes up a large share of capacity in the Interconnection Queue (55% solar; 33% storage)

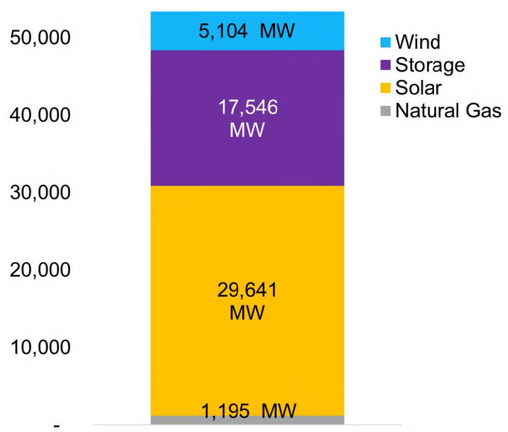
Virginia Existing Capacity 2023 [1]
MW



Virginia Annual Generation 2023 [2]
% of generation mix



Virginia Queued Capacity "Active" in PJM Queue as of April 1, 2024 [2]
MW



[1] EIA, 2023 [2] https://pjm.com/-/media/library/reports-notices/state-specific-reports/2023/virginia.ashx

Policy Landscape in Virginia

+ **In 2020, the Virginia legislature passed the Virginia Clean Economy Act (VCEA), which commits the state to an ambitious clean energy transition via several key provisions:**
  - Zero-Carbon Electricity: Established a mandatory renewable portfolio standard (RPS) program requiring the investor-owned utilities such as Dominion Energy and American Electric Power (AEP) to deliver electricity from renewable and other zero-carbon sources by 2045 and 2050 respectively
    - 100% of sales not met by non-renewable forms of zero-carbon electricity (e.g. nuclear) must be supplied by renewables
    - Of the zero-carbon electricity supplied by renewables, 75 percent of generation must be supplied by in-state projects; the remaining 25 percent can be supplied in the form of “unbundled” RECs purchased from out of state renewable projects
    - 16 GW of in-state solar and onshore wind, 5 GW of offshore wind and 3 GW of energy storage were determined to be “in the public interest”
    - Requires the retirement of existing fossil fuel plants by 2045 except when addressing specific reliability concerns; prior to 2045; requires the SCC to consider the social cost of carbon when considering construction of a new generating facility
  - Established schedule of noncompliance deficiency payments, starting at $45 to $75 per MWh and increasing by 1% annually after 2021
  - The legislation also includes important provisions to advance Environmental Justice and Energy Efficiency objectives, which are not modeled and are beyond the scope of this study

+ **Status of VCEA Compliance and Planning**
  - Utilities in the state, including Dominion, have expressed concerns about costs and implementation timelines in light of projected data center demand growth
    - Dominion’s 2024 IRP stated the modeled compliance case, with no new gas and no fossil retirements by 2045, is infeasible due to the unrealistic amount of imports and renewable builds that would also cause reliability concerns
    - SCC has indicated concerns, such as in response to past IRPs, about Dominion’s progress in complying with VCEA and identifying least cost options

+ **Virginia recently attempted to withdraw from the Regional Greenhouse Gas Initiative (RGGI); however, the Circuit Court of Floyd County recently ruled that the withdrawal was unlawful and without effect. This study assumed no RGGI requirement for Virginia since the analysis was performed prior to the recent court ruling**

https://energy.virginia.gov/renewable-energy/documents/VCEASummary.pdf
https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/2024-irp-w_o-appendices.pdf?rev=c03a36c512024003ae9606a6b6a239f3
https://www.governor.virginia.gov/newsroom/news-releases/2023/june/name-1005558-en.html

Scope of Work

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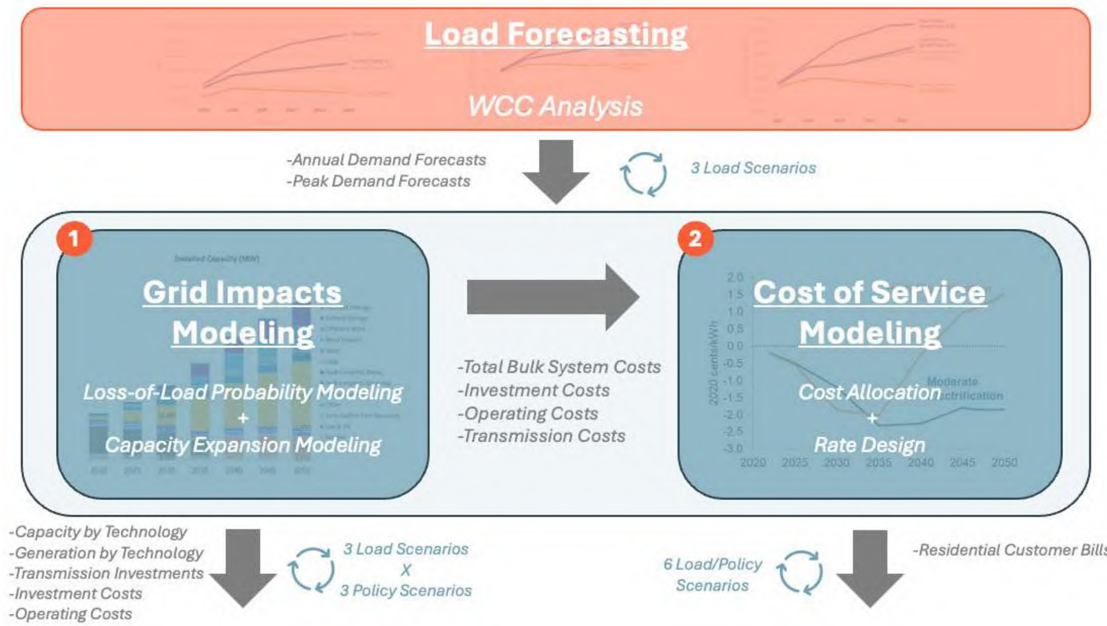
Scope of Work and Analytical Framework

- E3 was commissioned by JLARC to examine the impacts of data center growth on electric infrastructure needs and associated costs, as well as the distribution of these costs across customer classes
- Data center growth projections under a Moderate and Unconstrained scenario were provided by WCC as inputs into E3's analysis
- E3 leveraged its in-house electric sector models, RECAP[1] and RESOLVE[2], to identify the least-cost portfolios to meet load growth while also achieving policy goals and maintaining reliability
- Electric sector infrastructure investments were then assessed through a Cost of Service framework to examine existing and modified rate designs and the distributional impacts of these investments under different methods



The Grid Impacts Modeling included the entire PJM region while focusing on data center load growth projections from WCC for the DOM transmission zone. The Cost of Service assessment then focused on three load-serving entities within the DOM transmission zone (Dominion, Mecklenburg electric co-op (MEC), and Northern Virginia electric co-op (NOVEC)).

[1] https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/
[2] https://www.ethree.com/tools/resolve/

Electric Infrastructure Study Overview

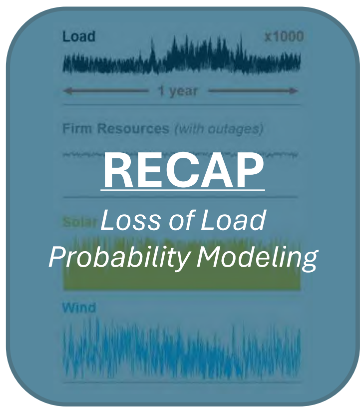
Key Objective of Infrastructure Analysis: Examine electricity system infrastructure and associated investments required to meet the VCEA goals under a wide range of potential data center-driven load growth scenarios

*To perform this work, E3 leveraged a **capacity expansion model** in tandem with a **loss of load probability model**, in order to ensure the resulting portfolios are reliable over a broad range of weather conditions.*

E3 modeled the entire PJM region within its capacity expansion framework to allow more detailed examination of the interaction between Virginia and the broader market in the context of rapid data center growth. However, by design we did not model the PJM market construct precisely in terms of price formation of energy and capacity prices.

This analytical framework identifies the total infrastructure requirements but does not distinguish between utility-owned infrastructure vs. 3rd party owned vs. "behind-the-meter" generation at data center facilities.

1a Use LOLP model to quantify "effective load carrying capability," which measures contribution of each resource to reliability across 100s of simulations



Technology ELCC curves

Optimized Portfolios

1c Use LOLP model to simulate resulting portfolios across wide range of conditions, validating resource adequacy

1b Use capacity expansion to optimize future portfolios to meet reliability and clean energy goals while minimizing cost

Rate Impact Study Overview

Key Objective of Rate Impact Analysis: Determine if current rate and fee structures lead to an equitable distribution of costs between data centers and other customers

How does the magnitude and pace of data center growth in Virginia influence these cost components?

Where do data center rates exist on this spectrum?

What is the range of equitable outcomes?

Marginal Costs	New Costs	Contribution to Fixed Costs
Data Centers must pay at least their marginal costs of service to avoid shifting the burden inequitably to existing customers	**New costs may be direct (e.g., administrative) or indirect (e.g., network upgrades) and may be difficult to quantify or assign**	**Contributions by data centers to system fixed costs benefit existing customers; however, excessive contributions are inequitable to data centers**

Overview of Scenarios and Sensitivities (1/2)

Scenarios for this analysis were constructed to examine the impacts of data centers on the Virginia electric system along two dimensions:

1. **Levels of data center growth**
   - [Counterfactual] No Data Center Growth ("S1" cases)
   - Moderate (half of Unconstrained) Data Center Growth ("S2" cases)
   - Unconstrained Data Center Growth ("S3" cases)
2. **Levels of VCEA achievement**
   - [Counterfactual] No VCEA Compliance ("A" cases)
   - Achievement of VCEA by Investor-Owned Utilities ("B" cases)
     - The VCEA only applies to investor-owned utilities, and electric co-operatives are exempt from the VCEA requirements; in other words, the "B" cases are consistent with current law.*
   - Full Statewide Achievement of VCEA requirements ("C" cases)
     - By 2045 around 62% of the projected data center loads in Virginia are served by co-operatives in WCC's forecast; E3 examined the full statewide achievement cases for better understanding of a potential bookend scenario

All scenarios include current "on-the-books" federal policies, including the Inflation Reduction Act and EPA carbon dioxide regulations, as well as current state policies and targets in the rest of PJM; exploring scenarios incorporating potential changes to currently enacted policies and rules was outside the scope of this study

VCEA Achievement →

Higher Data Center Growth ↓

S1A *No data center growth; non-compliant with VCEA*	**S1B** *No data center growth; IOUs comply with VCEA* *(current requirements)*	**S1C** *No data center growth; all statewide sales meet VCEA* *(beyond current requirements)*
S2A *Moderate data center growth; non-compliant with VCEA*	**S2B** *Moderate data center growth; IOUs comply with VCEA*	**S2C** *Moderate data center growth; all statewide sales meet VCEA*
S3A *Unconstrained data center growth; non-compliant with VCEA*	**S3B** *Unconstrained data center growth; IOUs comply with VCEA*	**S3C** *Unconstrained data center growth; all statewide sales meet VCEA*

*All references to VCEA compliance scenarios in the JLARC Report refer to existing VCEA requirements, or the "B" scenarios. Full statewide achievement of the VCEA in the "C" scenarios is strictly exploratory and only for reference in the E3 Report.

Overview of Scenarios and Sensitivities (2/2)

- **Across all core scenarios analyzed, constraints were implemented within the model to reflect the feasibility of building out new resources in Virginia within a given timeframe, based on historical pace of build, expected constraints on in-state development such as availability of land, and other factors**
  - Under the most aggressive scenario combining unconstrained data center growth with statewide VCEA achievement (**S3C**), which goes beyond current legislated requirements, E3 also examined bookend sensitivities in which specific constraints were relaxed:
    - **High In-State Renewables**: Higher levels of onshore wind available and accelerated deployment of offshore wind allowed in Virginia and North Carolina
    - **Regional Coordination**: Relaxed constraints on transmission build-out post-2035
    - **Nuclear Renaissance**: No constraints on nuclear build-out post-2035 such as on small modular reactors

VCEA Achievement →

Higher Data Center Growth ↓

S1A *No data center growth; non-compliant with VCEA*	**S1B** *No data center growth; IOUs comply with VCEA* *(current requirements)*	**S1C** *No data center growth; all statewide sales meet VCEA* *(beyond current requirements)*
S2A *Moderate data center growth; non-compliant with VCEA*	**S2B** *Moderate data center growth; IOUs comply with VCEA*	**S2C** *Moderate data center growth; all statewide sales meet VCEA*
S3A *Unconstrained data center growth; non-compliant with VCEA*	**S3B** *Unconstrained data center growth; IOUs comply with VCEA*	**S3C** *Unconstrained data center growth; all statewide sales meet VCEA*

Contextualizing this Study within the PJM Market

- **The modeling framework for this study relied on a PJM-wide capacity expansion framework, which allowed us to endogenously capture key market dynamics between Virginia utilities and the rest of PJM at a high level. This modeling assumes that the region can achieve long-run equilibrium; constraints on the pace of infrastructure development may remain a limiting factor in practice**
- **This study leveraged publicly available inputs and assumptions for the rest of PJM, e.g. using load growth projections from the 2024 PJM load forecast and assuming that all other states in the region meet their existing policy targets**
  - This study was narrowly focused on the impacts of different data center growth trajectories **within Virginia**; in other words, the amount of data center-driven load growth in all other states in the region was held constant across all scenarios at the levels assumed in the PJM 2024 load forecast
  - Similarly, policies in all neighboring states were held constant across all scenarios
- **The capacity expansion framework allowed Virginia utilities to access capacity and RECs from outside of their service territories; however, it is important to note that this was a high-level representation and did not seek to directly capture the nuanced dynamics of capacity and REC markets:**
  - **Capacity:** Dominion was assumed to be able to purchase capacity from the PJM market at a fixed price up to 3 GW, after which it would also need to build new transmission to access firm capacity
  - **RECs:** The capacity expansion model was able to build out-of-state renewables to meet the VCEA, up to the 25% limit. Note that this study did not consider the potential for Accelerated Renewable Energy Buyers to purchase their own RECs, which are not subject to the in-state requirements
- **While beyond the scope of this study, a detailed exploration of the impacts of data center growth on PJM capacity and REC markets is a worthwhile subject for future analysis, in order to more comprehensively understand how changes in these markets and corresponding price impacts will affect affordability in Virginia and the region as a whole**

Data Center Load Growth Projections

Key Finding #3: *If current trends continue, data center load growth could lead to as large as a tripling of electric sector demand in Virginia in the Unconstrained Data Center Growth scenarios, relative to today's levels, by 2050*

Key Finding #4: *This level of large and sustained demand growth driven by a single large customer type would be unprecedented in recent U.S. history, and would place significant pressure on system planners' ability to build sufficient generation, transmission, and distribution infrastructure to keep pace*

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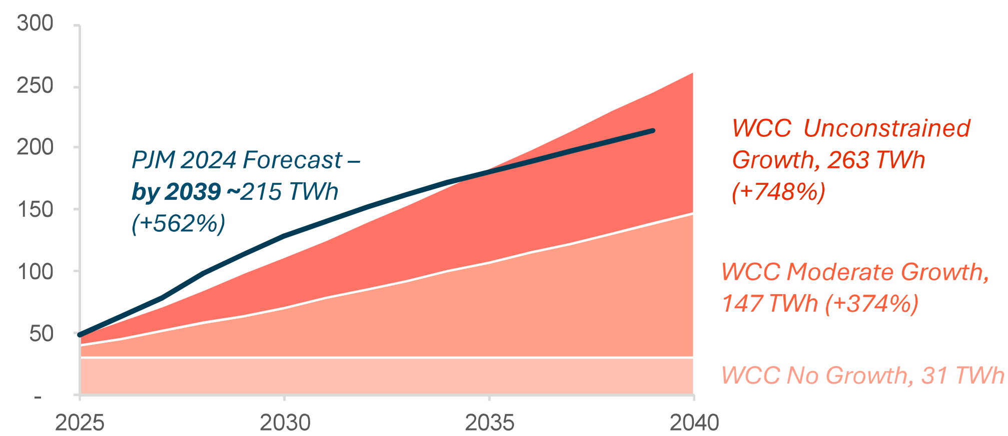
Data Center Load Projections from WCC

+ **UVA's WCC developed load projections for 2024-2040 for 3 data center growth scenarios**
  - The Unconstrained and No Growth scenarios serving as bookends to illustrate the difference between a sustained unconstrained growth BAU scenario vs. a counterfactual of no growth post 2023
  - The WCC scenario projections focused on data center growth in Virginia, assuming it is all located in the DOM transmission zone (including customers of Dominion, NOVEC, and Rappahannock)
    - The 2024 PJM public forecast was used for data centers outside DOM and VA - in AEP, APS, and East – and kept constant across scenarios
+ **The WCC projections are generally aligned with the 2024 PJM load forecast**
  - PJM forecasted that 2039 peak data center demand in DOM will be close to 25 GW, which translates to ~215 TWh annual loads with E3's estimated load factor and losses

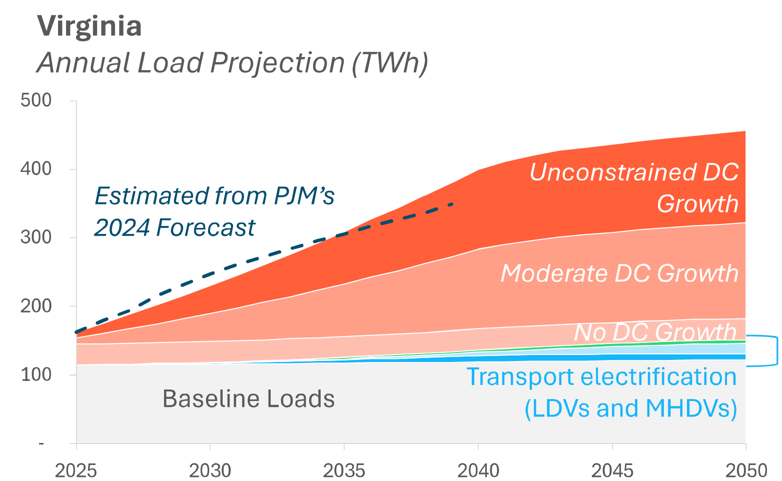
Virginia - Data Center Load Projections
Annual Load, TWh



Note: WCC data center growth projections were developed for Virginia, assuming all growth occurs in the DOM transmission zone. Unless otherwise specified, all references to demand and infrastructure build-out in the Dominion area or "DOM Zone" throughout this deck refer to the entire **Dominion transmission zone** within PJM, not just sales and generation provided by the Dominion utility.

Virginia Annual Load Projections

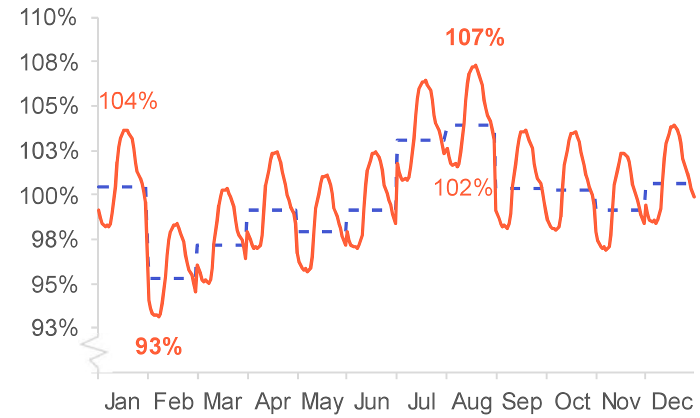
- **WCC also provided projections for Virginia for baseline residential and commercial loads as well as vehicle electrification loads by utility, in order to capture the rest of the Commonwealth's system with the same level of details**
- **Annual energy demand in Virginia, before data centers, grows steadily around 1% per year, leading to a cumulative growth of 26% in Virginia by 2050**
  - The non-data center load forecasts are extended beyond 2040 with constant growth rates
- **The ~300 TWh of data center loads by 2050 under the Unconstrained Data Center Growth scenarios triple loads in Virginia**
  - Only data center loads in Dominion, from WCC's forecast, are assumed for Virginia
  - After 2040, when WCC's forecast ends, E3 assumes data center load growth slows down to 1%/year



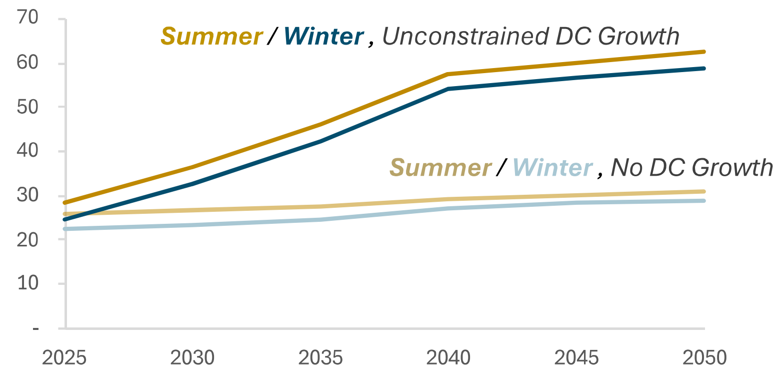
Peak Load Projections

+ **Peak demand is calculated by applying hourly load profiles for the baseline loads, electrification loads, and data center loads, respectively**
+ **In the next few decades, baseline load and transportation electrification load grows steadily in both Virginia and PJM-wide**
  - In both regions, system slowly transitions from summer peaking to dual peaking by 2050, without data center load growth
+ **With the growth of data centers, the system remains summer peaking in Virginia**
  - Data centers more than double Virginia's peak load by 2050 in the Unconstrained Growth case
  - The difference between summer and winter data center peak loads is only around 3%, but given the magnitude of these loads this effect is noticeable

Month-hour Data Center Load Profile
% of average annual load



Virginia - System 1-in-2 Peak Projection (GW)



Grid Impact Analysis

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Modeling Framework and Key Assumptions

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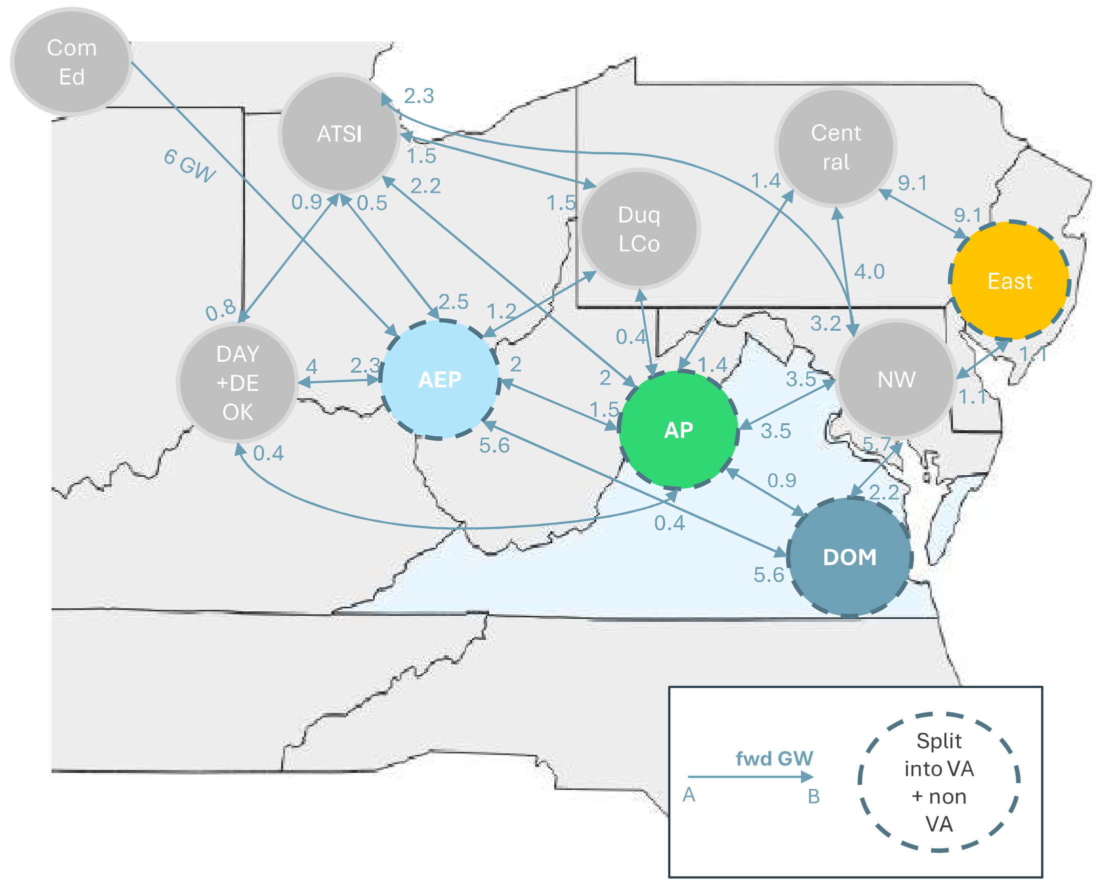
Capacity Expansion Topology

- **E3 modeled capacity expansion for the PJM market in RESOLVE with 10 load and capacity zones - with those overlapping with Virginia (DOM, AEP, AP, East) broken into VA vs non-VA subzones**
  - This topology allows us to model VA specific assumptions and constraints (e.g. WCC's load forecast and VCEA policies) while capturing the broader market dynamics within PJM
  - Transmission constraints between these zones are derived from information provided by Energy Exemplar
  - Transmission upgrades between DOM and its neighboring zones (AEP, AP, and NW) are modeled as an option to allow more detailed examination of transmission infrastructure upgrade needs to support data center load growth in Northern Virginia
- **The modeling horizon covers 2025-2050 for this study**



Key Modeling Assumptions

+ **Load Forecasts** derived from information provided by WCC and published by PJM (2024)
+ **Existing Resources** grouped by zones, technology, fuel, and quality tiers (e.g. high/mid/low heat rates for thermal units)
  - Planned resources expected through 2027/2028 included as expected additions
+ **Candidate Renewable Resource Potential** drawn from the National Renewable Energy Laboratory's (NREL) ReEDS supply curve
  - Potentials, capacity factors, and interconnection costs for solar PV, onshore wind, and offshore wind candidate resources
+ **Candidate Resource Costs** developed leveraging NREL's 2024 Annual Technology Baseline (ATB) forecast and standard E3 financing assumptions
  - Includes escalating local network upgrade costs for renewables which are developed based on transmission projects recently approved by PJM in the DOM zone, in addition to the specific resource interconnection costs from NREL ReEDS
+ **Policy Assumptions**
  - EPA regulations, post 2030, constrain new gas builds to a 40% annual capacity factor and require existing coal units to co-fire with natural gas
  - RGGI modeled for participating states (NJ, MD, DE) in the East transmission zone, with price forecast developed by E3
  - States' RPS policy and clean energy carveouts modeled
  - VCEA requirements considered in the VCEA compliance scenarios

Regional and Sub-Regional Resource Build Limits

+ **Build limits are implemented by technology, location, and future model year**
  - *Resource potentials* - Based on NREL ReEDs and with further adjustments, each resource type has a **total potential build amount** available for each of several subzones (also known as NREL's "p-zones"). These potentials inform the **quality and location** for an exhaustive list of candidate resources.
  - *Interconnection limits* – Based on geographical location relative to the grid and **how much new transmission would need to be built** to link resources to the existing grid. These limits also dictates the **pace of resource potential availability** over the modeling period, assuming further out resources are not available right away in 2030 and 2035.
  - *Build rate limits* – Based on historical build rates and the interconnection queue by zone and by technology, the model constrains **how much can reasonably be built by 2030** (more stringent) and by 2035 (less stringent) in each major zone. These **build rates apply to renewables as well as thermal resources and storage**.
+ **The amount of capacity that can be added in a given area also incurs higher transmission network upgrade costs**
  - *Deliverability limits* – Based on estimated **grid upgrade requirements** in each subzone, new renewable resources need to be accompanied by substation and transmission line upgrades which have their own **implied costs and upgrade rate limits**. Solar and wind resources in the same subzones share the same deliverability limits and required upgrade costs.

Scenario Matrix

Assumptions/Scenarios	No DC Growth No VCEA	No DC Growth With VCEA	Moderate/Unconstrained DC Growth No VCEA	Moderate/Unconstrained DC Growth With VCEA
Load	No Data Center load growth in VA post 2023	No Data Center load growth in VA post 2023	Moderate or Unconstrained Data Center load growth	Moderate or Unconstrained Data Center load growth
VCEA Compliance	No	Yes (IOU or Statewide)	No	Yes (IOU or Statewide)
Existing Thermal	Economic Retirement	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs	Economic Retirement	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs
Candidate Renewables, Storage, Gas	Build rate limits through 2035	Build rate limits through 2035	Build rate limits through 2035	Build rate limits through 2035
Hydrogen	Not available	Available [1]	Not Available	Available [1]
SMR (nuclear)	Not available	Available 2035+ with build limits	Available 2035+ with build limits	Available 2035+ with build limits
Capacity Purchases and Transmission Upgrades	Capacity purchase allowed up to 3 GW; No transmission upgrade allowed	Capacity purchase allowed up to 3 GW; No transmission upgrade allowed	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits

[1] The consumption of hydrogen for power generation would also require additional fuel delivery and storage infrastructure; the costs of such infrastructure is captured at a high level on a $/MMBtu basis. However, these costs assume that Virginia is able to access a robust regional hydrogen economy that is already in place in the future, and costs would be higher if Virginia is building new / first-of-a-kind infrastructure.

Impacts of Data Center Load Growth on System Reliability Needs

***Key Finding #4-2:** While data center computing loads do not vary significantly between seasons or within a day, the sheer volume of data center growth shifts the timing of reliability needs to times when total facility demand is marginally higher due to cooling needs, in the summer afternoons and evenings*

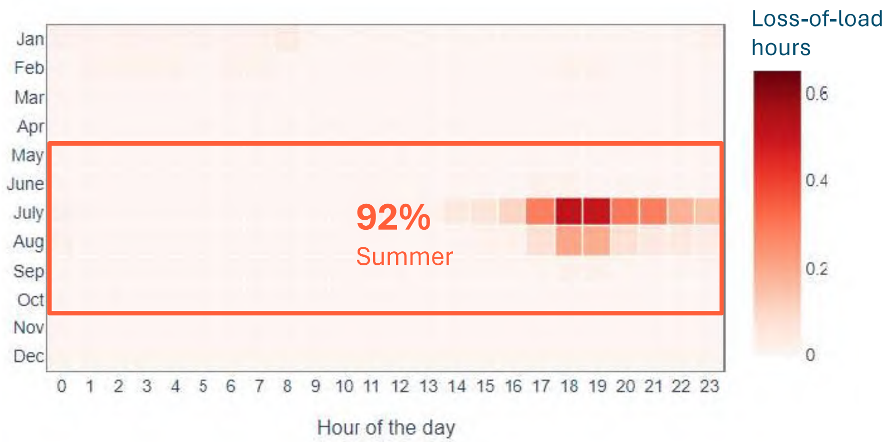
***Key Finding #4-3:** The high cooling demand of data centers which typical peak in afternoon summer hours, creates opportunities for synergistic pairings of solar and battery storage although their reliability contributions eventually saturate. Large quantities of firm, dispatchable capacity will also be needed to meet demand growth reliably*

Energy+Environmental Economics

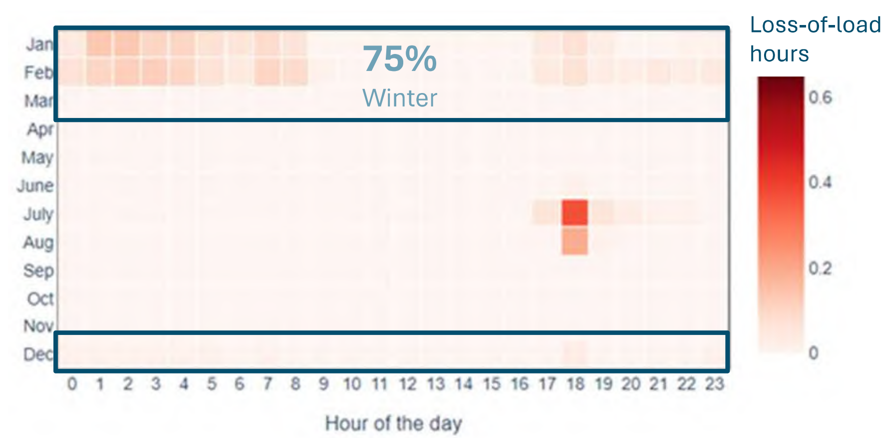
System Reliability Risks without Data Center Growth

- **E3 modeled system reliability needs for the Dominion transmission zone, where all data center growth are projected for Virginia, and the entire PJM, in order to evaluate resource capacity contributions in these areas**
- **In 2025, most of the loss of load risks in Dominion system are observed in summer months**
  - The most challenging periods are concentrated in late afternoons after sunset
- **Without data center load growth, system loss of load risks shift to winter by 2050 when high gross load coincides with thermal unit outages**
  - Resources that can generate during summer early evenings or can provide energy for an extended time window in winter tend to have higher capacity value

2025 – Existing Dominion System



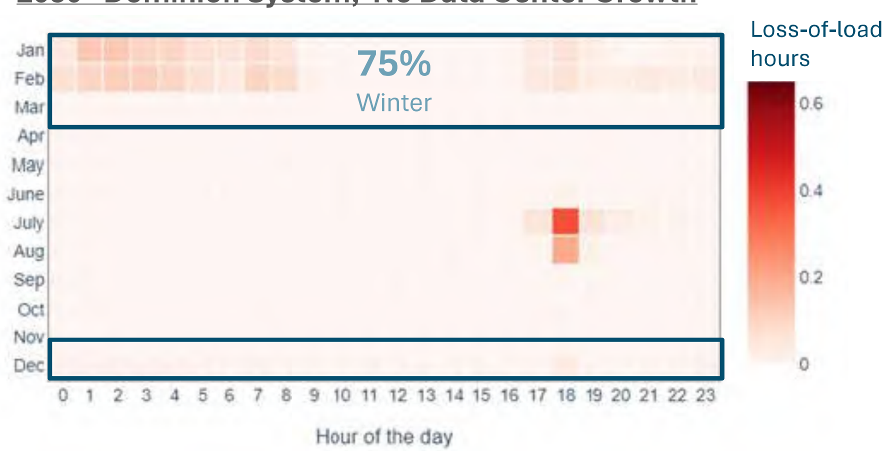
2050 – Dominion System, No Data Center Growth



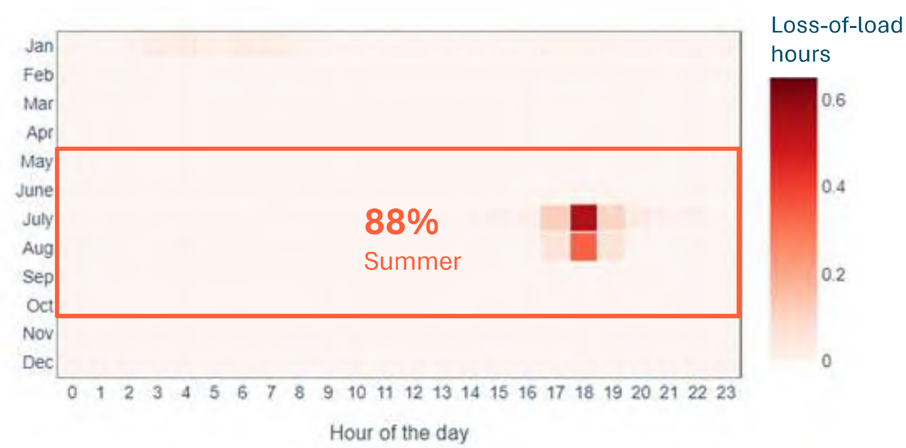
System Reliability Risks with Data Center Load Growth

- **Projected annual load for Dominion almost triples by 2050 under the unconstrained data center load growth scenarios**
- **While data center computing loads do not vary significantly between seasons or within a day, the sheer volume of data center load growth shifts the timing of system reliability needs to times when total facility demand is marginally higher due to cooling needs, in the summer afternoons and evenings**
- **Resources that can generate during summer early evenings have higher capacity value**

2050 –Dominion System, No Data Center Growth



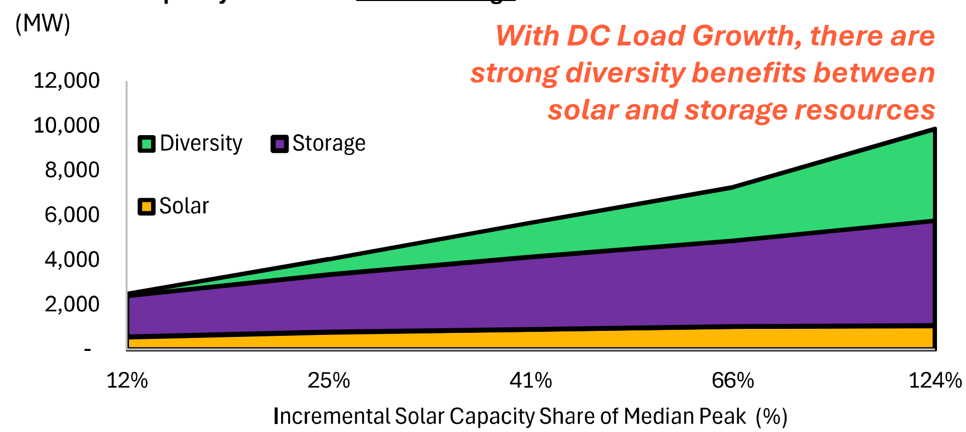
2050 – Dominion System, with Unconstrained Data Center Growth



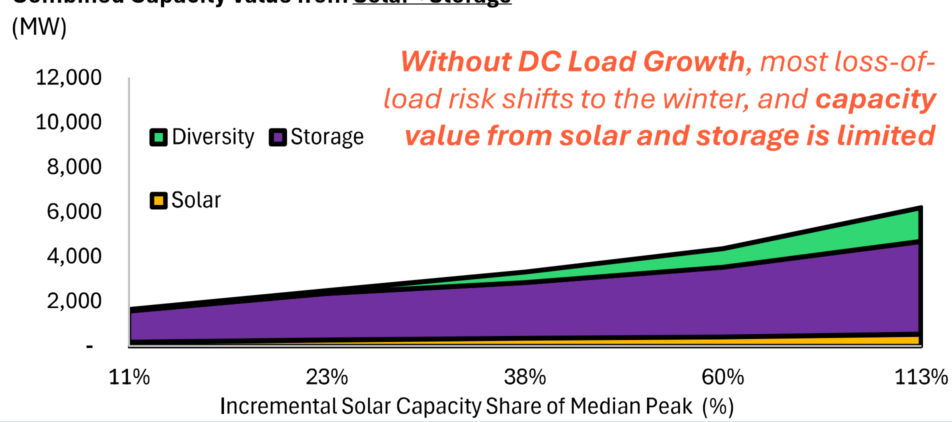
Complementary Reliability Impacts between Solar and Storage

- **Adding solar and storage can quickly exhibit saturation effects, while combinations of the two resources exhibit interactive benefits**
  - Positive interactive effects between solar and storage are referred to as "diversity benefits"
- **This comes from the complimentary nature of the two resources**
  - Abundant solar makes the net load evening peaks sharper, which increases value of limited duration energy storage resources
  - This is more prominent when data center load growth is presented, which creates concentrated reliability challenges in summer afternoons

Combined Capacity Value from Solar +Storage



Combined Capacity Value from Solar +Storage



Impacts of Data Center Load Growth on Electric Sector Resource Portfolios

Energy+Environmental Economics

Baseline Results (S1A)

Key Finding #1: *In the No Growth scenario without the VCEA, Virginia is projected to meet new demands through an expansion of solar and battery energy storage capacity, coupled with a moderate increase in natural gas generation capacity to meet reliability needs*

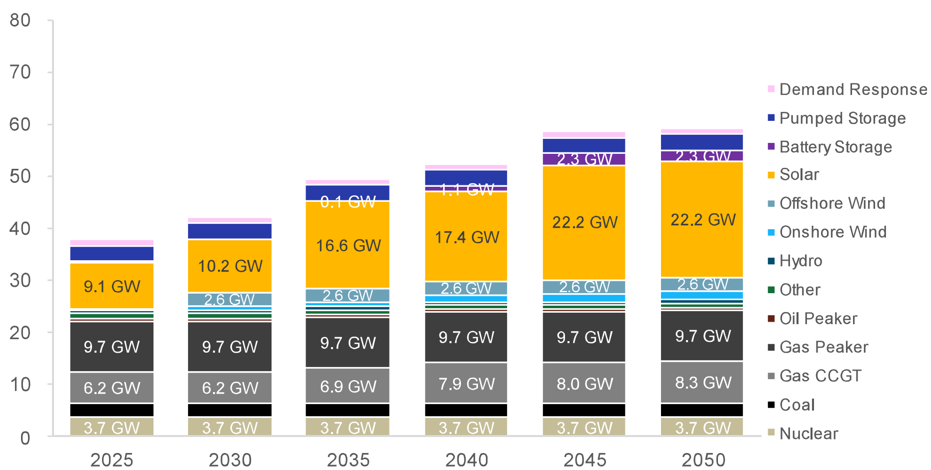
S1A: No Data Center Growth, No VCEA Dominion – *Capacity and Generation*

S1A

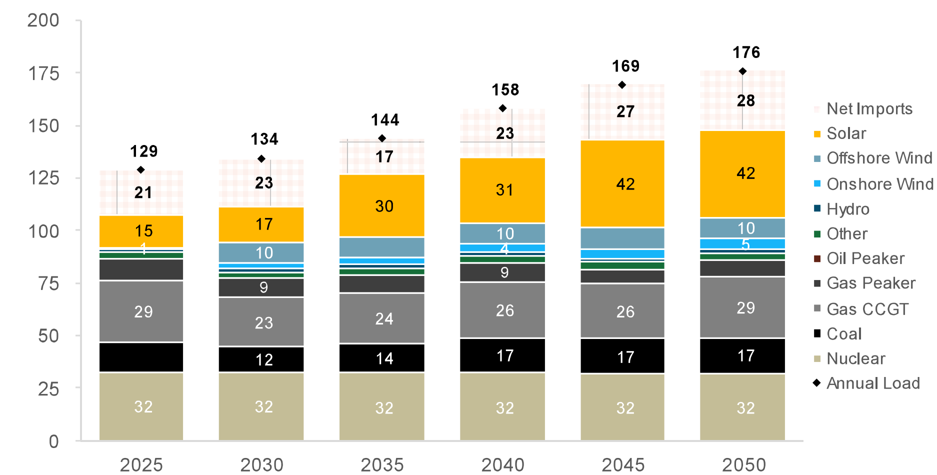
No data center growth; non-compliant with VCEA

- **Majority of increased energy demand is met by growth in solar generation, as costs decline and the Inflation Reduction Act tax credits provide additional support**
- **Storage provides complementary capacity value for solar, and additional reliability needs are met with gas CCGT additions**
  - Onshore wind selected where available, but the total amount is limited considering land and development constraints in Virginia and North Carolina
- **All thermal resources remain online through 2050 in the absence of carbon policy**

Dominion Installed Capacity
GW



Dominion Annual Generation
TWh



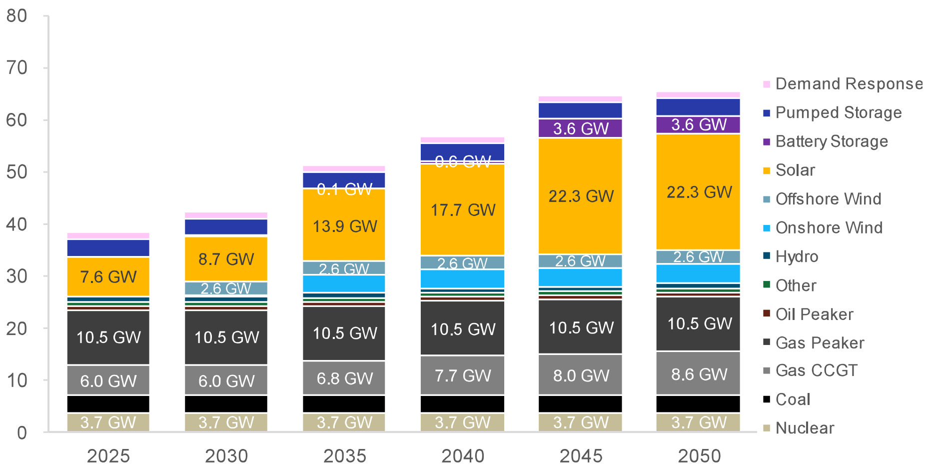
S1A: No Data Center Growth, No VCEA VA – *Capacity and Generation*

S1A

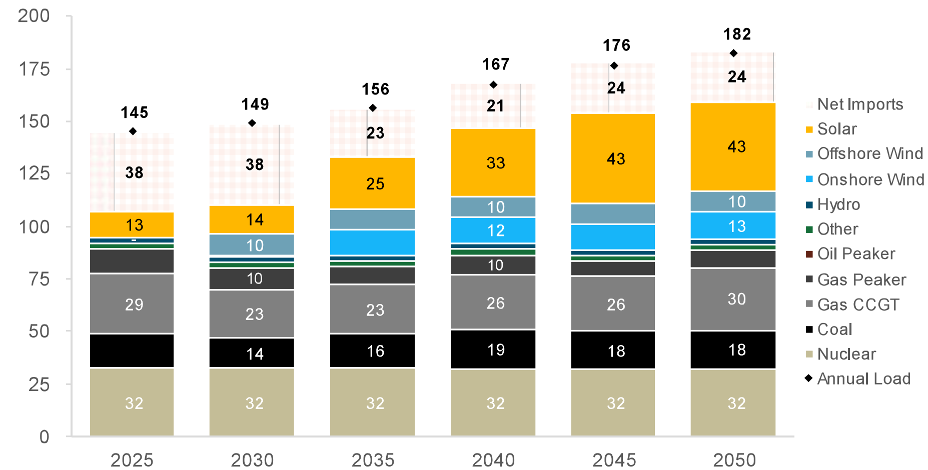
No data center growth; non-compliant with VCEA

- **By 2050, Virginia is projected to meet nearly 24% of its energy demand with solar generation**
- **In the absence of policy, there is still a significant role for coal and gas generation, comprising another ~30% of demand**
- **The remaining demand is met through a combination of nuclear, onshore and offshore wind, and market purchases**

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



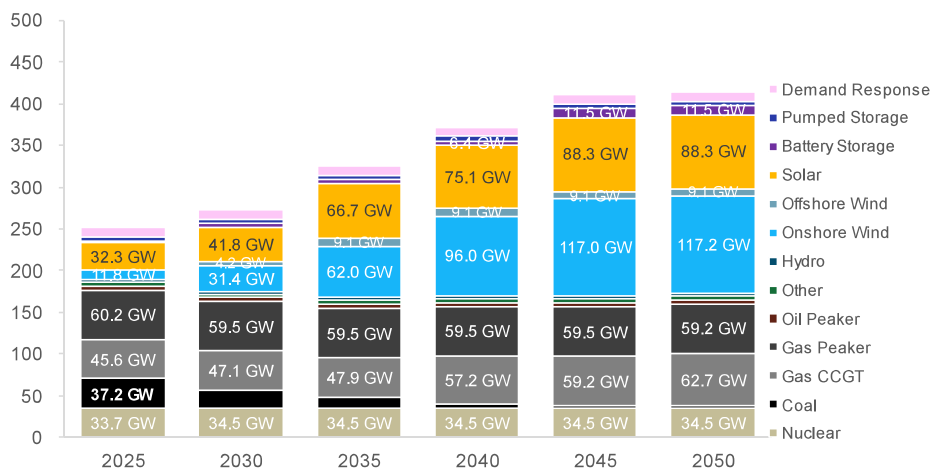
S1A: No Data Center Growth, No VCEA
PJM – *Capacity and Generation*

S1A

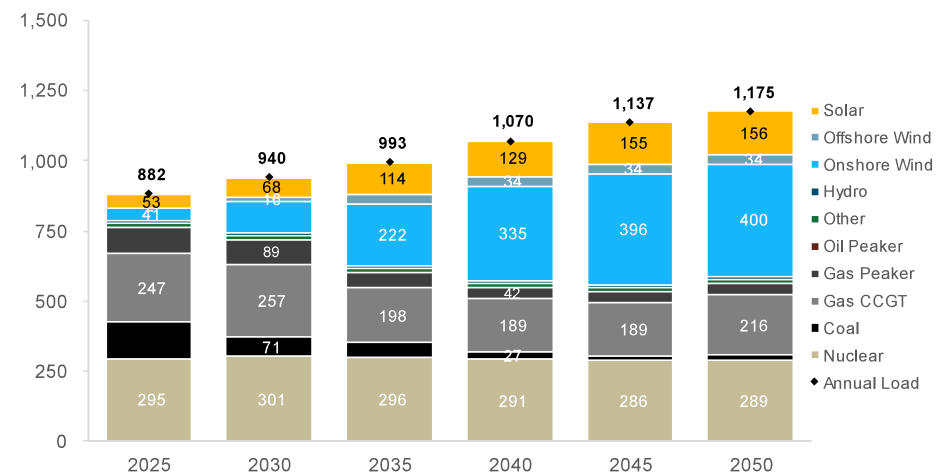
No data center growth; non-compliant with VCEA

- **Large amount of coal retirements, coupled with mild demand growth, drive economic additions of onshore wind, solar+storage, and gas CCGT capacity**
  - Significant amounts of onshore wind are added across the PJM region due to strong resources and favorable economics, coupled with the impacts of the Inflation Reduction Act tax credits
- **Renewable generation increases significantly across the PJM region; gas generation declines slightly, due in part to the impacts of EPA regulations on new gas units**

PJM Installed Capacity
GW



PJM Annual Generation
TWh



Impacts of VCEA

Without Data Center Growth

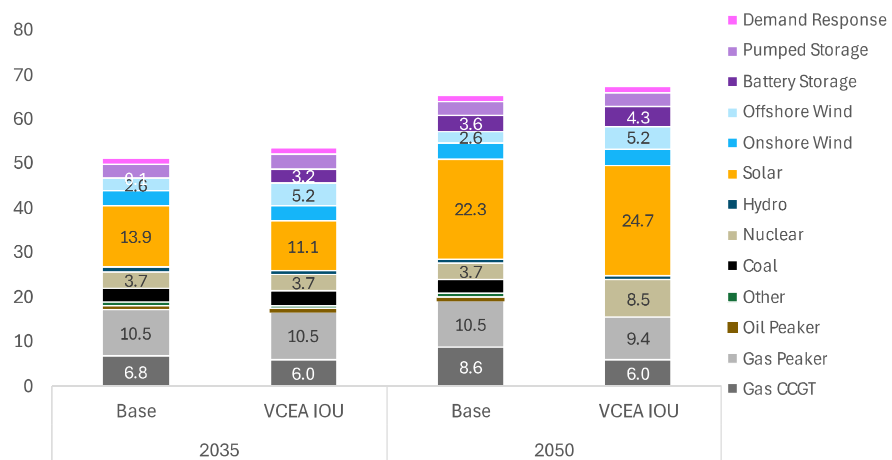
Key Finding #2: *In the No Growth scenario, achievement of the VCEA is projected to drive the development of new nuclear capacity (in the form of SMRs), additional solar builds, as well as conversion of gas facilities to hydrogen to meet system reliability needs*

Impacts of VCEA Compliance: S1B vs S1A VA – *Capacity and Generation*

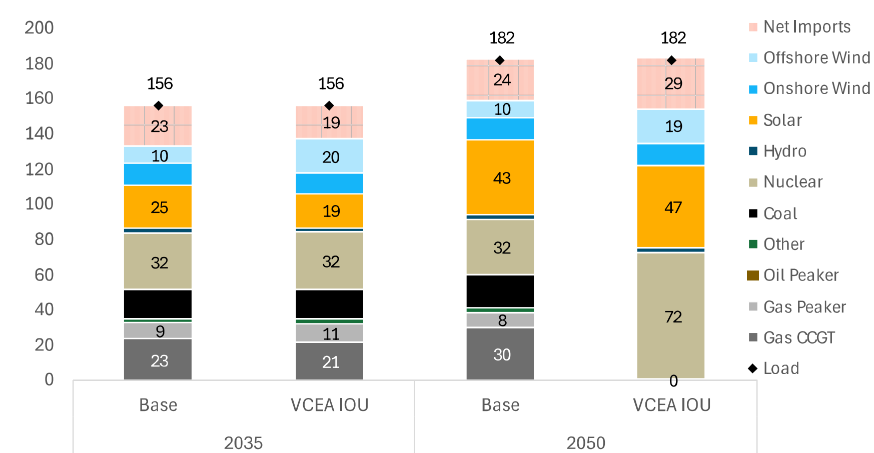
S1A	S1B
No data center growth; non-compliant with VCEA	*No data center growth; IOUs comply with VCEA*

- The VCEA has a limited impact in the near term, primarily driving an acceleration of offshore wind builds coupled with additional battery storage resources
- In the longer term, the VCEA has a more significant impact, leading to an increase in nuclear capacity, while gas resources are converted to run on hydrogen and remain online to maintain system reliability

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



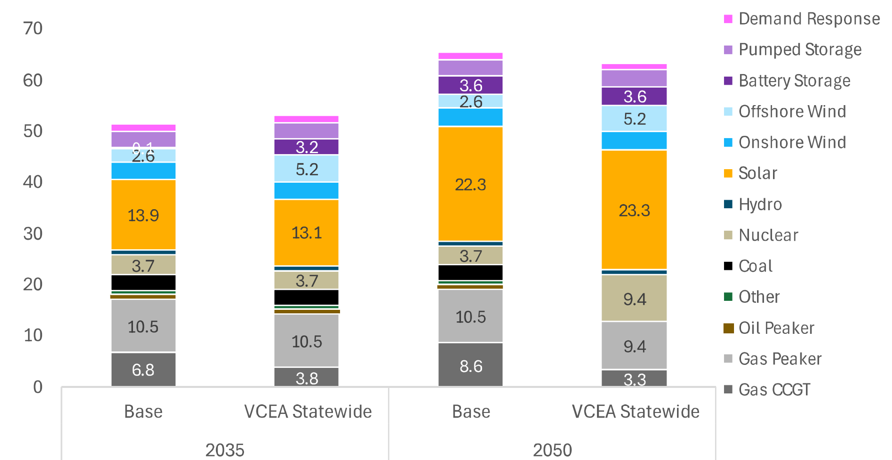
Impacts of VCEA Achievement: S1C vs S1A VA – *Capacity and Generation*

S1A	S1C
No data center growth; non-compliant with VCEA	*No data center growth; all statewide sales meet VCEA*

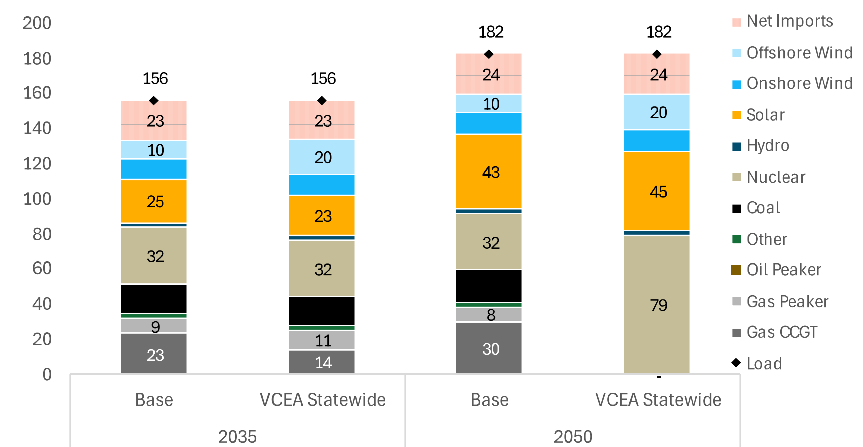
+ Expanding the VCEA requirements to all utilities in Virginia (including co-ops) has marginal impacts on system buildout dynamics in the absence of data center load growth

- Loads served by electric co-operatives remain a relatively small share of total load in Virginia

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



Impacts of Data Center Growth

Without VCEA Compliance

Key Finding #5: *In the absence of state policy, data center load growth is projected to drive a build-out of a diverse mix of resources, including gas, solar, nuclear, offshore wind, and battery storage*

Key Finding #6: *Without the VCEA in place, data center growth could lead to a significant increase in the region's reliance on gas generation*

Key Finding #7: *Meeting demand growth would require sustaining a very high pace of new capacity additions through 2040, including new resources that have not been widely deployed today such as SMRs and offshore wind*

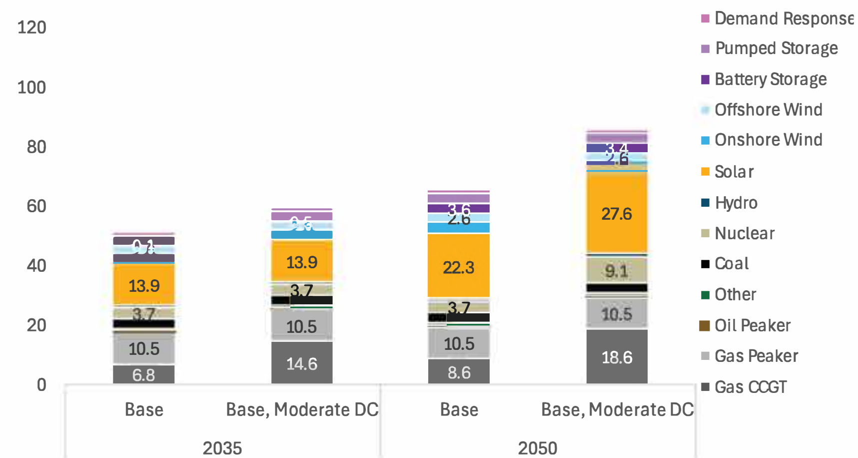
Energy+Environmental Economics

Impacts of Data Center Growth: S2A vs S1A VA – *Capacity and Generation*

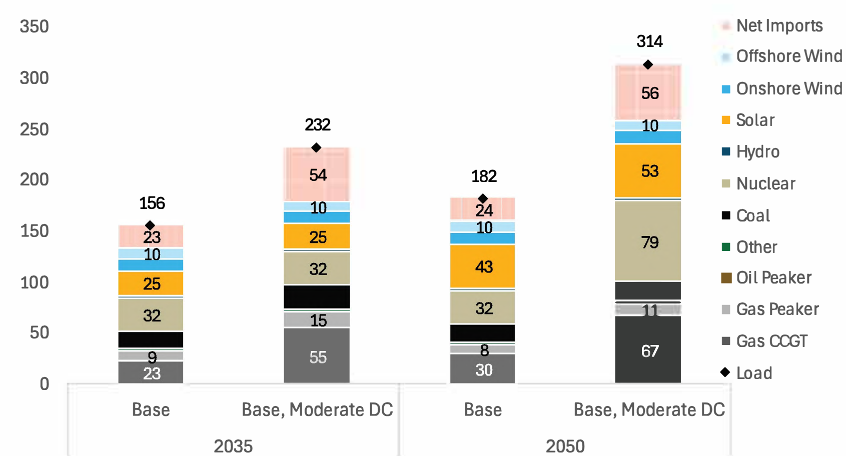
S1A	S2A
No data center growth; non-compliant with VCEA	*Moderate data center growth; non-compliant with VCEA*

- **Under Moderate levels of data center growth, Virginia will need to invest in significant new gas capacity over the next decade in order to keep pace with demand growth**
- **In the longer term, over 5 GW of additional nuclear capacity, along with additional solar and storage capacity, are projected to be added in order to meet increasing energy demands**
- **Import for Dominion increases compared to the no growth case, driving the need for 3.1 GW transmission expansion between the DOM zone and AP/Northwest**

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

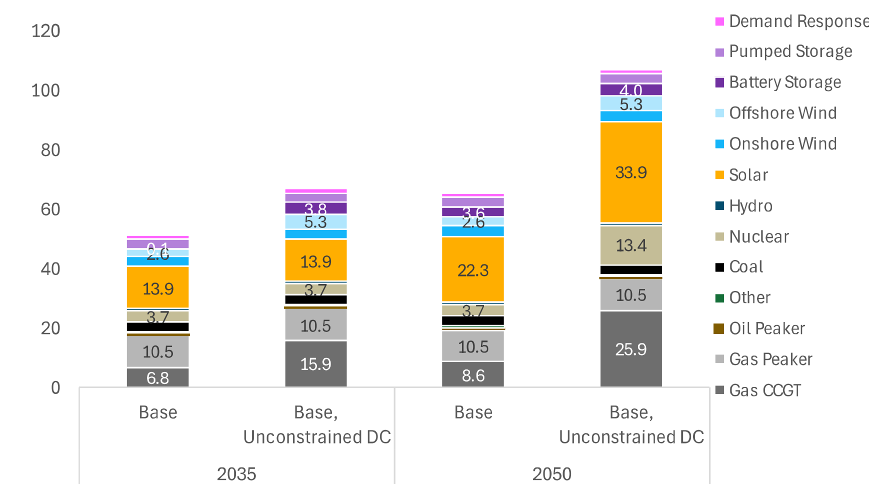


Impacts of Data Center Growth: S3A vs S1A VA – *Capacity and Generation*

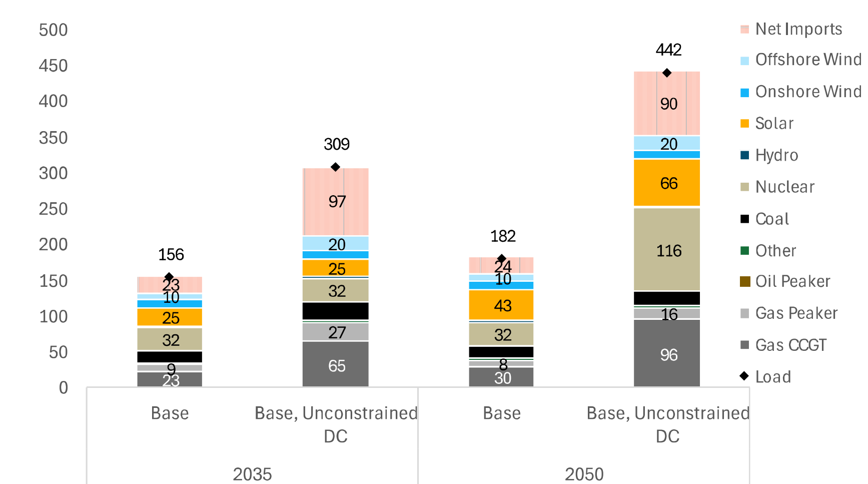
S1A	S3A
No data center growth; non-compliant with VCEA	*Unconstrained data center growth; non-compliant with VCEA*

+ **Under Unconstrained Data Center Growth, Virginia is projected to add significant amounts of new gas capacity at an accelerated rate in the near term, compared to the no growth case**
  - Keeping up with demand growth in the next decade would require Virginia to add capacity at a rate of 1 GW/yr for 15 consecutive years, double its average rate of capacity additions over the past decade
  - The Dominion system experiences challenges in meeting system demand in 2030, when the addition of resources are bounded by historical build rate and new technology options like SMRs are not available
+ **In the long term, Virginia is projected to add a diverse mix of resources, including 10 GW of new SMR capacity, over 25 GW of solar capacity, 20 GW of new gas, around 5 GW capacity purchases, coupled with additional offshore wind and battery storage, to meet sharply increasing energy demands**
  - 3.5 GW transmission expansion between the DOM zone and AEP, AP, and NW are needed to support increased capacity purchase and imports

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



Impacts of VCEA

With Data Center Growth

Key Finding #8: *With the VCEA in place, Virginia would likely require an unprecedented investment in an "all-of-the-above" strategy to meet demand growth with clean energy resources*

Energy+Environmental Economics

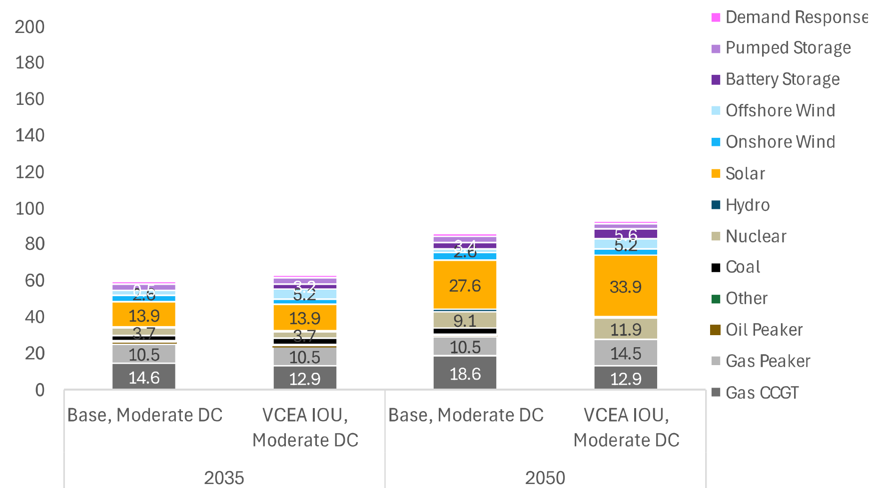
Impacts of IOU VCEA Achievement: S2B vs S2A VA – *Capacity and Generation*

S2A	S2B
Moderate data center growth; non-compliant with VCEA	*Moderate data center growth; IOUs comply with VCEA*

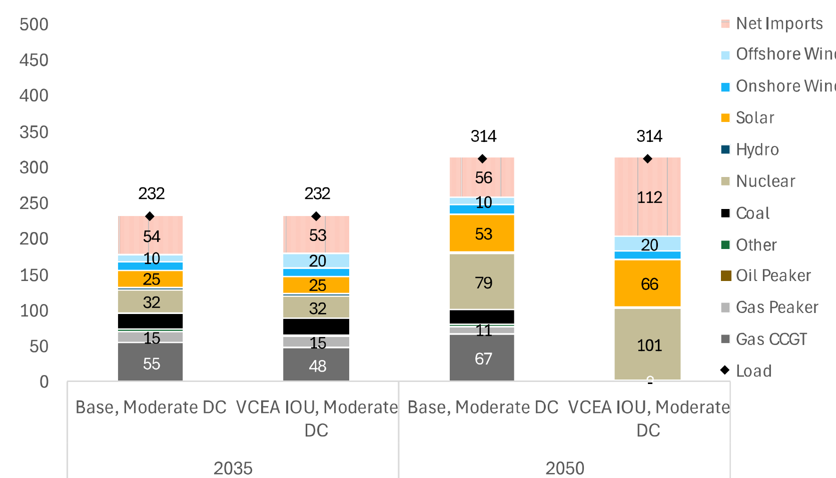
+ Meeting the goals of the VCEA under Moderate levels of demand growth would require significant shift towards investments in new renewables and transmission expansion, compared to the S2A case

- Virginia could add up to 26 GW of solar capacity and up to 5.5 GW of battery storage, coupled with offshore wind
- Nuclear capacity continues to be projected to play a significant role in meeting data center growth, increasing to nearly 12 GW
- Hydrogen-ready turbines, either through retrofits or new additions, play a significant role in maintaining system reliability
- Virginia relies on imported energy from the rest of PJM to meet 36% of total demand by 2050, as co-ops which are exempt from the VCEA requirements rely heavily on imports to meet increasing data center loads

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

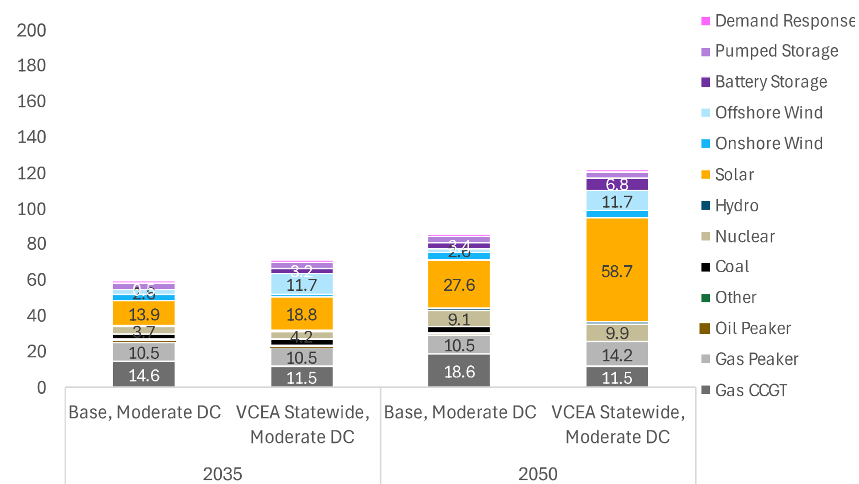


Impacts of Statewide VCEA Achievement: S2C vs S2A VA – *Capacity and Generation*

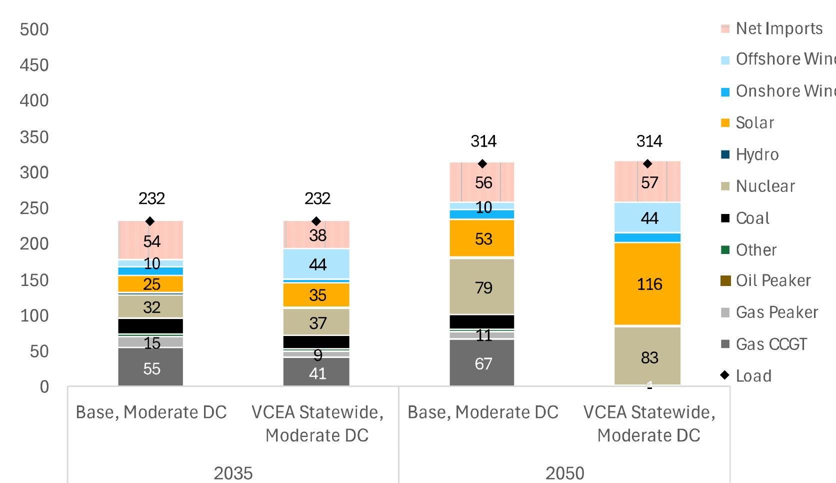
S2A	S2C
Moderate data center growth; non-compliant with VCEA	Moderate data center growth; all statewide sales meet VCEA

+ **Expanding the VCEA requirements to all utilities in Virginia (including co-ops) drives more in-state renewable investments and would reduce the state's reliance on imported energy from the PJM market**
  - Applying the VCEA goals to all statewide sales leads to an even higher build-out of renewable capacity in-state; Virginia is projected to add up to 51 GW of solar capacity and up to 12 GW of offshore wind capacity, coupled with 7 GW of battery storage
  - Nuclear and hydrogen continue to play a significant role in meeting data center growth and maintaining system reliability, respectively
  - The statewide application of the VCEA goals reduces the state's reliance on imported energy compared to the VCEA IOU case (S2B); however, new transmission is still projected to be developed to increase transfers between DOM and its neighboring zones

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

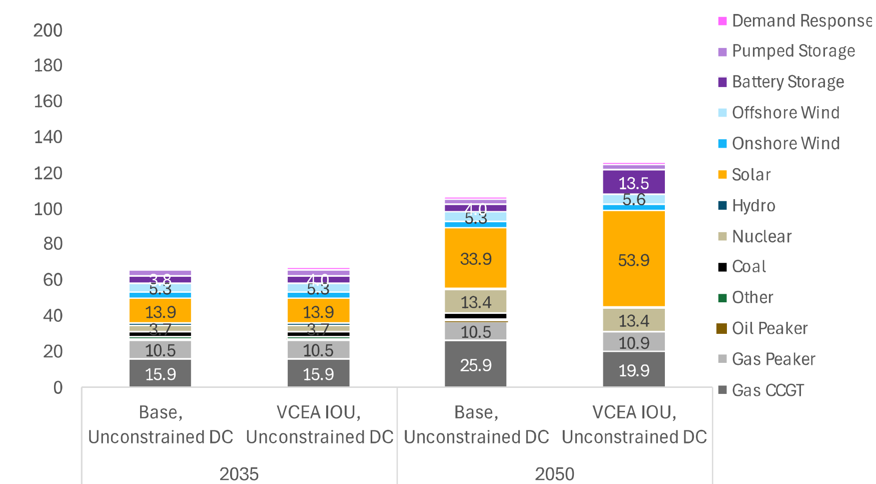


Impacts of IOU VCEA Achievement: S3B vs S3A VA – *Capacity and Generation*

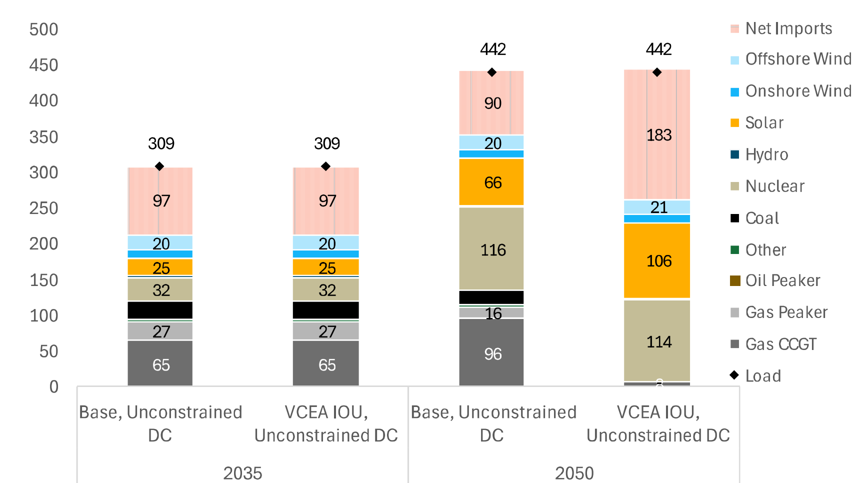
S3A	S3B
Unconstrained data center growth; non-compliant with VCEA	*Unconstrained data center growth; IOUs comply with VCEA*

+ **Under the Unconstrained Data Center Growth case, meeting the goals of the VCEA would drive significant new investments across multiple strategies and technologies, as well as a heavy reliance on the PJM market**
  - To meet increased energy demands with zero-carbon energy, Virginia is projected to add up to 46 GW of in-state solar and 13 GW of battery storage, in addition to 10 GW of new SMR capacity, 6 GW of new offshore wind capacity, and the conversation of existing gas fleet to run hydrogen by 2045
  - Virginia is also projected to build close to 9 GW of new transmission to import higher quantities of energy from the PJM market, relying on 180 TWh of imported energy or over 40% of total electric demand, with VCEA-exempt co-ops serving large quantities of data center demand with energy imported from the PJM market

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

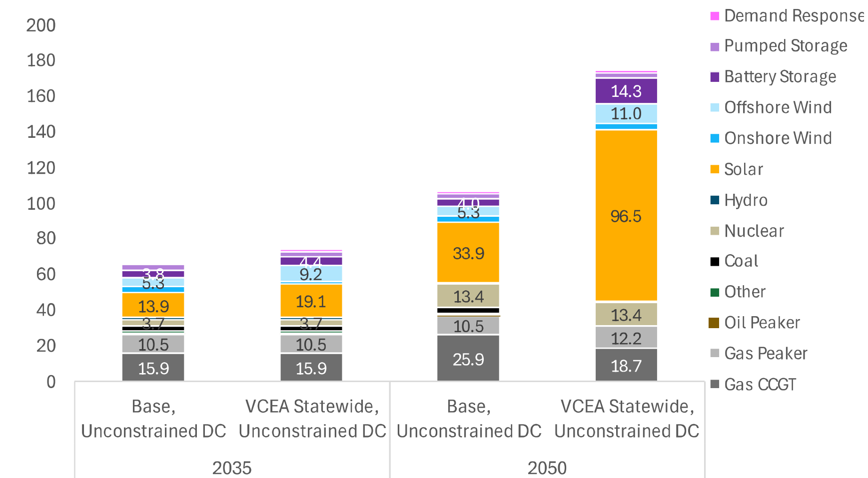


Impacts of Statewide VCEA Achievement: S3C vs S3A VA – *Capacity and Generation*

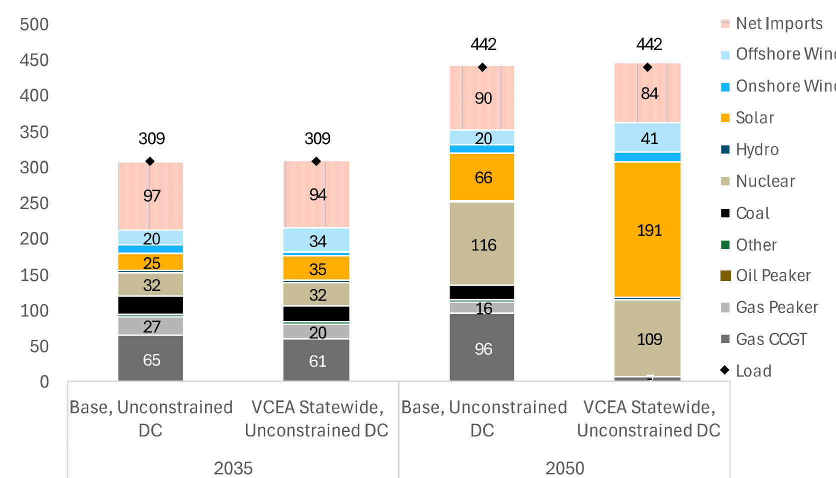
S3A	S3C
Unconstrained data center growth; non-compliant with VCEA	*Unconstrained data center growth; all statewide sales meet VCEA*

+ **Expanding the VCEA requirements to all utilities in Virginia (including co-ops) drives significantly more in-state solar and offshore wind builds, while reducing the use of import energy to meet system demand**
  - Virginia is projected to add close to 90 GW of solar and 11 GW of offshore wind by 2050 when the VCEA requirements are applied to all utilities
  - Import energy reduces compared to the VCEA IOU case (S3B) as new in-state renewable additions are required to serve data center loads with co-ops; however, around 9 GW transmission expansion is still projected to support the high amount of energy purchases needed in this scenario

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



Additional Sensitivities

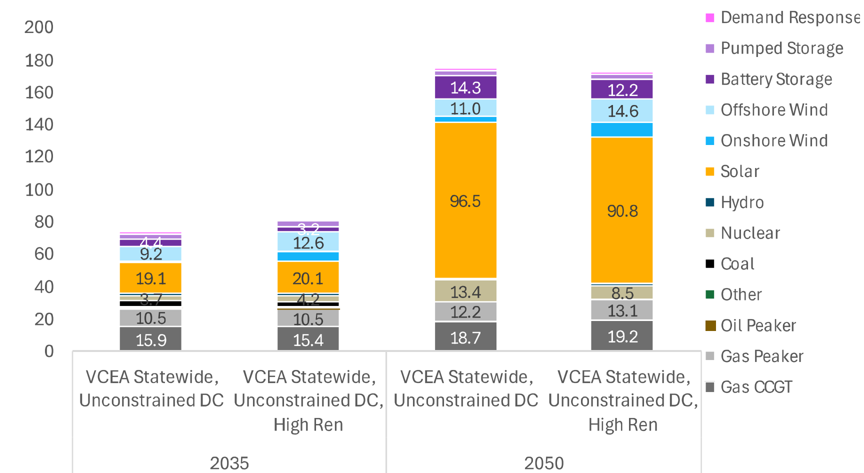
- **While each scenario examined presents both challenges and opportunities for the Virginia electric sector, the Unconstrained DC Growth + Statewide VCEA Achievement scenario (S3C) appears the most challenging based on the pace and scale of builds coupled with a high reliance on emerging technologies that have not yet been commercially demonstrated at scale**
- **E3 applied feasibility constraints within the model that limit the state's reliance on any one pathway or strategy; however, the scale of build-out is unprecedented and thus by definition the constraints are highly uncertain. Technology breakthroughs, permitting reform, and myriad other factors could accelerate (or constrain) the availability of specific technologies. To perform an initial, directional exploration of this uncertainty, E3 conducted three additional sensitivities:**
  - **S3C: High In-state Renewables (HiRen)**
    - Higher levels of onshore wind available in VA and NC;
    - Accelerated deployment of offshore wind allowed;
    - More conservative cost trajectory assumed using conventional nuclear costs and more stringent SMR build limits
  - **S3C: Regional Coordination (RegCoord)**
    - Relaxed constraints on transmission build-out post-2035
    - More conservative cost trajectory assumed using conventional nuclear costs and more stringent SMR build limits
  - **S3C: Nuclear Renaissance (NucRen)**
    - No constraints on nuclear build-out post-2035
- **These sensitivities were only explored under S3C assumptions; however, the same uncertainty applies to other scenarios as well**

High Renewables: Compared to S3C VA – *Capacity and Generation*

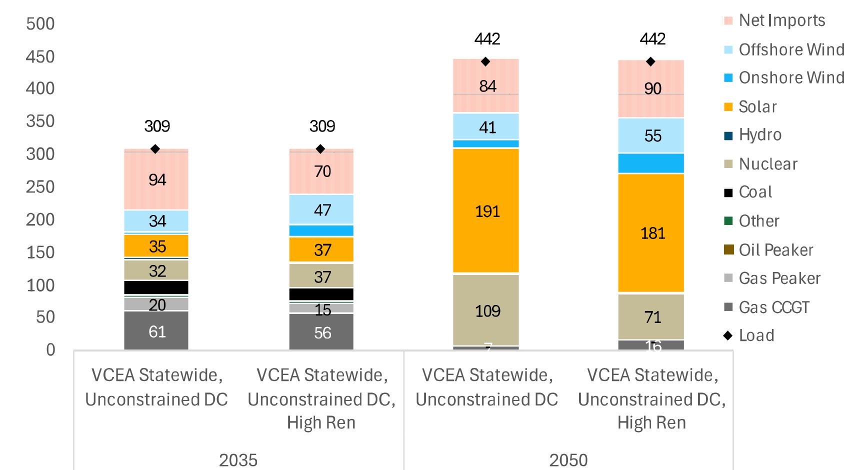
S3C	S3C: HiRen
Unconstrained data center growth; all statewide sales meet VCEA	*Relaxed renewable development constraints*

- In a scenario in which barriers to building onshore wind are overcome in VA and NC, and the development of offshore wind can be accelerated, Virginia is projected to add 5 GW more onshore wind and accelerate the build of offshore wind in the near term to meet the rapidly growing system demand
- More hydrogen-compatible turbines are added to meet system capacity need, complementary to renewable additions
- Under this scenario, the costs and availability of nuclear are also treated more conservatively, but nuclear still plays a critical role in meeting energy demands (constrained to the build levels in Dominion's 2023 IRP)

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

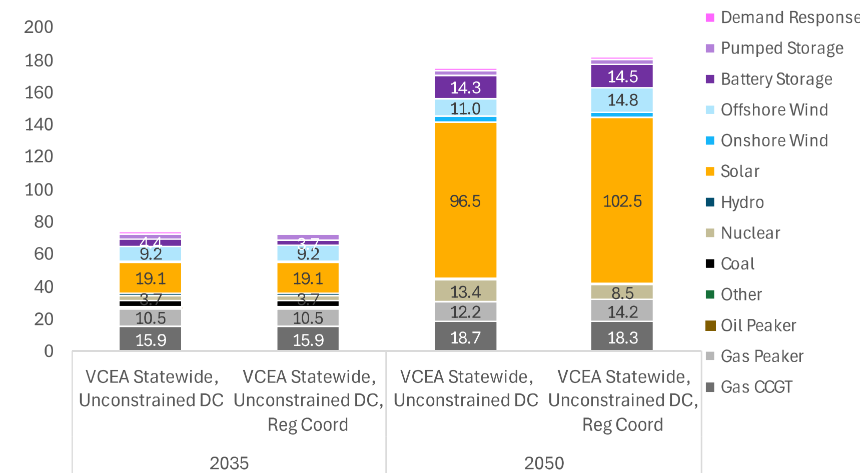


Regional Coordination: Compared to S3C VA – *Capacity and Generation*

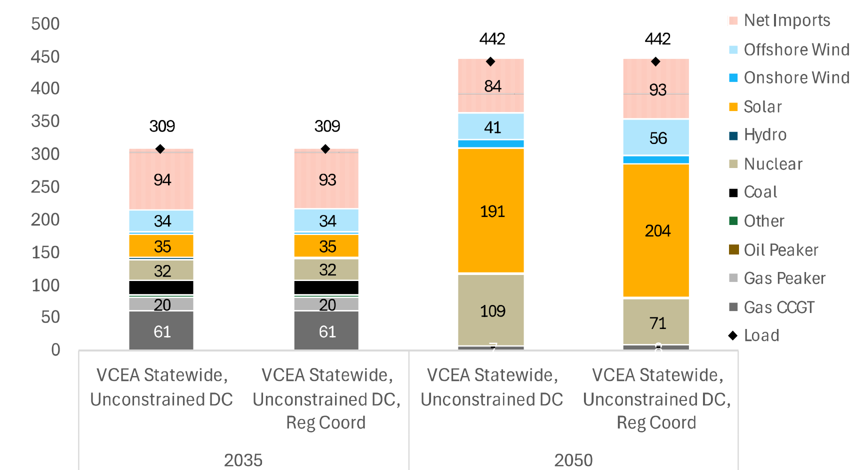
S3C	S3C: RegCoord
Unconstrained data center growth; all statewide sales meet VCEA	*Relaxed transmission development constraints*

- **Additional 3.4 GW transmission upgrade between DOM and AEP, AP, and NW, when made available, are selected by 2050 to support expanded economic imports and capacity purchases, despite higher cost of the expansion compared to expansion at a lower amount**
- **More solar, offshore wind, and hydrogen-compatible turbines are added, on top of transmission expansion, when SMR builds are further limited**

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh

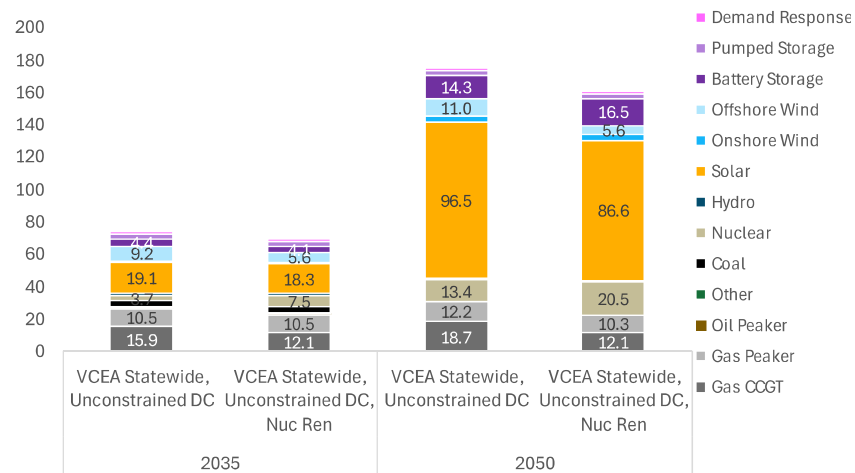


Nuclear Renaissance: Compared to S3C VA – *Capacity and Generation*

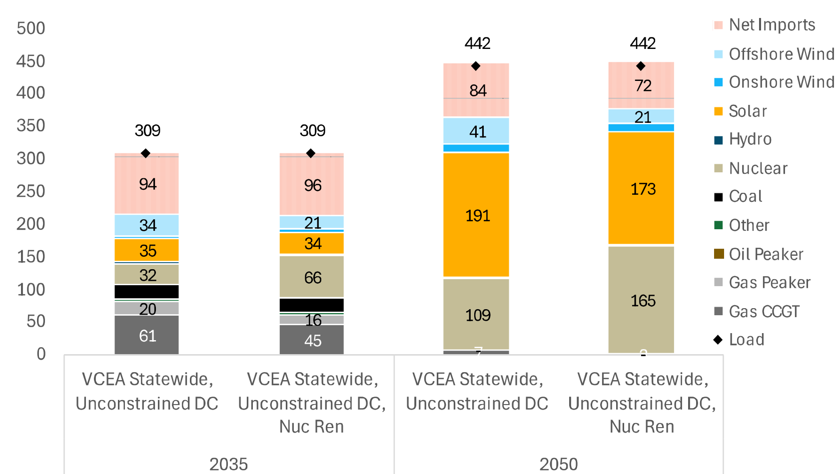
S3C	S3C: NucRen
Unconstrained data center growth; all statewide sales meet VCEA	*No nuclear development constraints*

- An incremental 7 GW SMR capacity is economically added in Virginia by 2050 when there are no constraints placed on the rate of capacity build-out
- This significant expansion of nuclear capacity, coupled with 2.3 GW of battery storage, offsets the need for around 10 GW of solar, 5.3 GW of offshore wind, and 8.5 GW of hydrogen-compatible turbines

Virginia Installed Capacity
GW



Virginia Annual Generation
TWh



Rate Impact Analysis

Energy+Environmental Economics

Rate Impact Considerations

+ **E3 focused on a representative subset of Virginia utilities to assess rates using best available data and documented assumptions**

+ **The following approach was used to assess rate impacts resulting from data center growth in Virginia:**
  - A broad review of existing rates, fees, cost-of-service studies, and policies was conducted for utilities identified
  - Costs and revenues associated with data center rate classes were assessed for equitable apportioning of costs under current and forecasted conditions
  - Residential rate impacts were evaluated based on modeled cost shifts due to data center load growth

+ **Specific sources of potential uncertainty in this study include:**
  - Significant differences in $ / unit costs by customer class – ideally these should be similar across classes
  - Dominion Virginia's service territory contains a small jurisdiction in North Carolina; instances where associated data was unable to be disaggregated is not expected to be consequential to findings in this report
  - The most recent, available rate schedules and cost-of-service studies were used as a basis for assessment; values were escalated, where necessary, to align most recent data with forecast
  - Distribution costs were not included in the forecast due to an expectation that most new data center loads will interconnect at transmission voltages; any distribution network investments are anticipated to be modest and easily attributed based on cost causation

Approach to Assessing Rate Impacts

Utility tariffs and cost-of-service studies informed how cost shifting may occur with escalating forecasts of costs and load

1. **Relevant tariffs for each utility were reviewed to determine current methods of revenue collection**
2. **Cost-of-service studies were examined to determine basis of volumetric and fixed costs**
3. **Compare volumetric revenue and cost components against each other and across rate classes**
4. **Calculate total cost and revenue by rate class using load forecast data**
   - Determine where total cost/revenue values do not align within classes
5. **Compare and highlight specific impacts for Residential customers served by Dominion Virginia under various cost recovery scenarios**
   - Extension of existing cost allocations
   - Updated cost allocations using current methodology to adapt to anticipated load growth

Revenues

Values	Description
$ / kW	Demand charges (if applicable)
$ / kWh	Delivery + supply + other volumetric adders
Fixed charges	Customer or minimum monthly charges
Data Sources	Utility Tariffs

Costs

Values	Description
$ / kW	Capacity-driven investment / Coincident demand
$ / kWh	Consumption-driven costs (e.g., generation)
Fixed costs	Utility billing, overhead, etc.
Data Sources	Project forecasts, cost of service studies, etc.

Utility Profiles, Costs, & Rates

Energy+Environmental Economics

Utility System Profiles

Dominion Virginia

>100 Data Centers

- **Customer count**
  - Residential: 2.3 million
  - Commercial & Industrial: 267,143
- **Peak demand:** 17.1 GW
- **Annual sales:** 92.9 TWh (8.5 TWh of which is delivery only)
- **Load growth:** Projected to increase from 17 GW in 2023 to 33 GW in 2048, including data centers and vehicle electrification[2]

MEC

1 Data Center

- **Customer count**
  - Residential: 29,816
  - Commercial & Industrial: 1,910
- **Peak demand:** 153 MW
- **Annual sales:** 860 GWh

NOVEC

~28 Data Centers

- **Customer count**
  - Residential: 164,645
  - Commercial & Industrial: 14,258
- **Peak demand:** 1.5 GW
- **Annual sales:** 8,526 GWh
- **Peak electric load growth:** >**12%/year** over 15 years, almost exclusively driven by data centers[1]

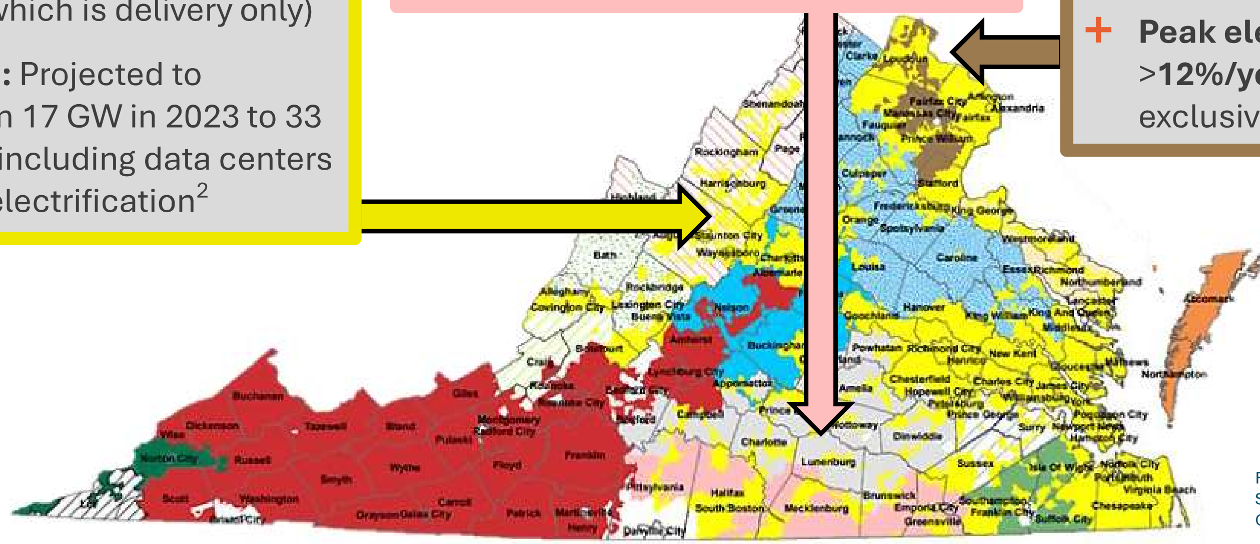


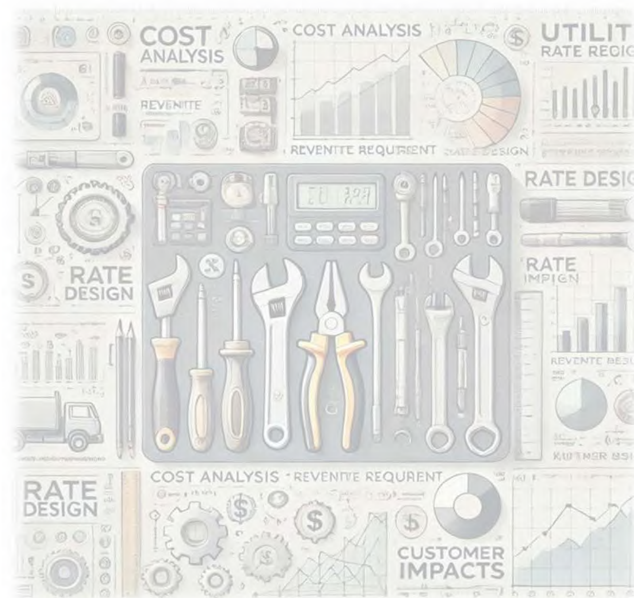
Figure is an approximation
Source: State Corporation Commission, 2020
Created by: Division of Public Utility Regulation, 2020

[1] NOVEC 2022-2023 Annual Report
[2] Dominion Virginia 2023 Integrated Resource Plan

Utility Assessment

E3 examined rate designs for three utilities in Virginia, each with different needs, interests, and approaches

+ **Dominion Virginia (“Dominion”)**
    - The largest load serving entity of the three examined with the most significant existing and forecasted data center load
    - An investor –owned utility with vertically integrated transmission service
        - Regulation compels biennial review of rates and other periodic stipulations by Virginia SCC
        - Serves as the transmission provider for PJM’s Dominion Load Zone (“DOM Zone”)
+ **Northern Virginia Electric Cooperative (NOVEC)**
    - As a public power cooperative NOVEC receives transmission service from Dominion and provides distribution service to its members
+ **Mecklenburg Electric Cooperative (MEC)**
    - A public power cooperative receiving transmission service from Old Dominion Electric Cooperative (ODEC) and providing distribution services to its members



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Cost Recovery and Rate Adjustment

Wholesale Cost Recovery

- **PJM allocates capacity cost obligations from its Reliability Pricing Model to load zones based on five coincident peak (5-CP) demand; Dominion allocates these capacity costs to utilities based on a 5-CP methodology**
  - Utilities further apportion their share of the allocated wholesale costs according to their individual rates
- **PJM allocates transmission costs on 1-CP construct; Dominion then allocates these transmission costs to utilities based on a 12-CP average**
  - Utilities apportion their share of the allocated wholesale costs according to their individual rates
- **Wholesale market design and transmission tariffs undoubtably influence retail costs, beyond the scope of this analysis and may warrant additional study**

Retail Cost Recovery

- **Under Virginia law, the State Corporation Commission (SCC) conducts biennial reviews of the Commonwealth's investor-owned utilities, including an examination of its earnings, consideration of adjustments to its base rates, or modifications of terms and conditions**
- **Riders are reviewed by the SCC separately on an annual basis**
- **Requirements are less strict for public power cooperatives, like NOVEC and MEC**

Retail Rate Equity

Energy+Environmental Economics

Rate Equity Today

- **Current rates appropriately apportion costs to classes and customers responsible for incurring them**
- **Load growth is expected to increase system costs in Virginia with some effects directly attributable to new, large loads (i.e., data centers)**
- **Investor-owned utilities and public power cooperatives use different approaches to manage the costs of new loads joining the system; each effectively insulates existing customers from potential cost shifts and rate impacts resulting from large loads entering the system**
  - Investor-owned utilities absorb infrastructure investments in rate base and recover costs over time from the interconnecting customer through cost allocations
    - Long-term, minimum, monthly cost recovery structure, like Dominion's "Monthly Contract Dollar Minimum" guarantee, can reduce risk, but not mitigate it entirely
    - Accurate recovery of infrastructure investments made on behalf of the interconnecting customer requires proper calibration of cost allocation factors
  - Public power cooperatives tend to assign all infrastructure investment costs to the interconnecting customer upfront while structuring direct passthrough of all incremental costs; some contribution to embedded (i.e. existing or average system) fixed costs are made through distribution charges
    - Upfront payment for interconnection costs mitigates risk of stranding assets or under-recovery of investments

Various Approaches to Cost Recovery

Cost Recovery Method

Embedded Cost Allocation ← → **Directly Assigned Costs**

Dominion

- Data centers are included with other industrial customers in GS-3 (distribution voltage) and GS-4 (transmission voltage) rates
- All non-redundant investments necessary for service and interconnection are provided by the utility, with costs recovered over time through cost allocation factors applied to the corresponding rate class.
- Variable costs are based on metered contribution to average costs of transmission and generation
  - Unbundled generation is offered through retail choice
- Contribution to system fixed costs is recovered through cost allocation as determined by the portion of plant costs attributed to each rate class portion of plant

NOVEC

A dedicated HV-1 rate class strictly serves data center customers

- Interconnection costs are assigned to the customer through a series of deposits and installment payments as the project develops
- Generation is offered as an embedded rate or through an unbundled option
- System costs recovered through rate design whereas delivery charges are cross-subsidized
- The load factor requirement under HV-1 rate class ensures demand charges recover the cost if the dedicated substation use is below contracted capacity.
- The HV-2 rate class, for the largest data center customers, limits energy supply options to market rate, protecting other customers from the increased risk and cost due to growing load from data centers

MEC

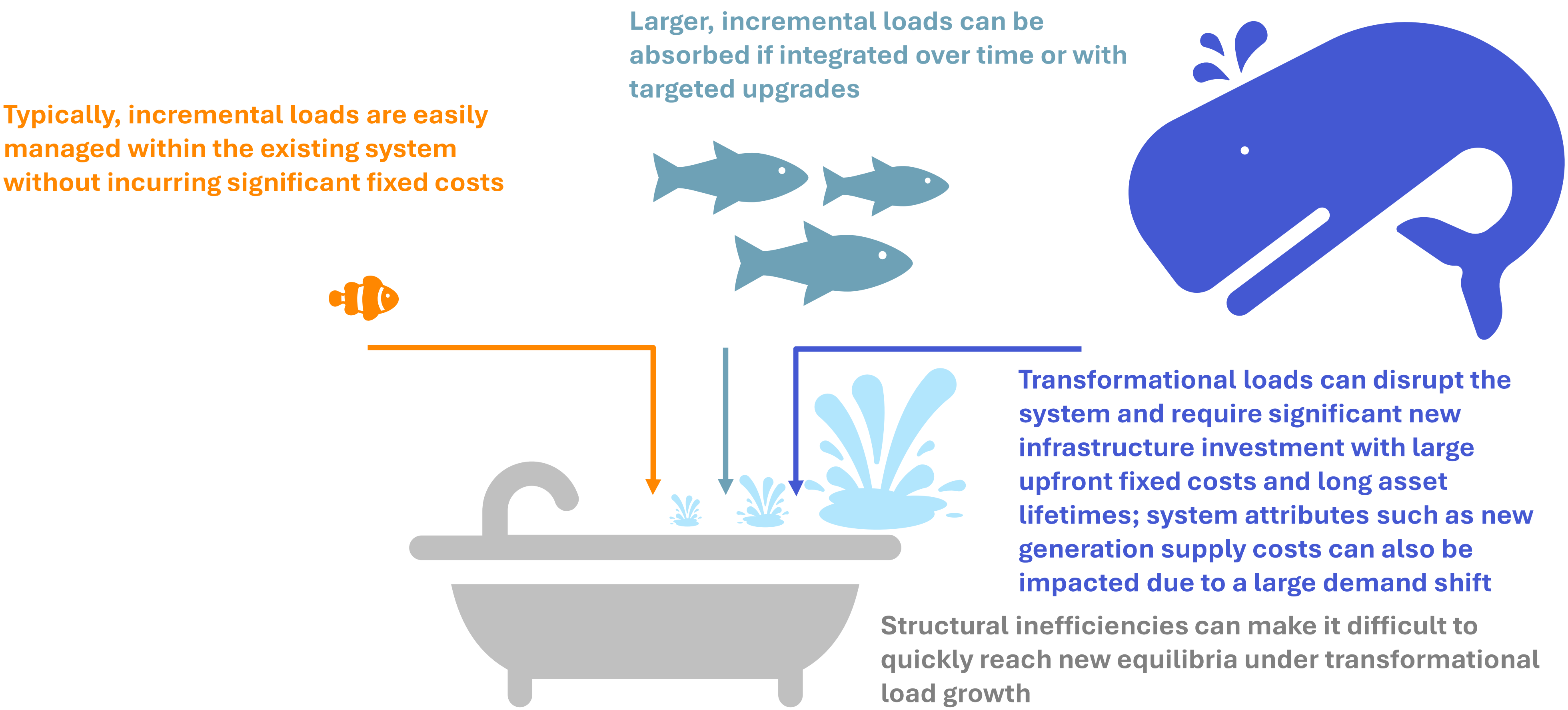
With only one data center customer, Mecklenburg has a dedicated rate class tailored specifically to the facility that fully and directly assigns all costs

- Interconnection costs are paid by the customer concurrent with development
- All generation is paid for directly through a separate Energy Services Agreement (ESA)
- The data center built and paid for dedicated substations that are metered for direct allocation of contributions toward system transmission and capacity costs
- Distribution charges are designed to recover costs for supporting system operations and maintenance
- Delivery charges are intended to collect contribution toward embedded fixed costs and provide some benefit (i.e., return) to other cooperative members

Rate Dynamics

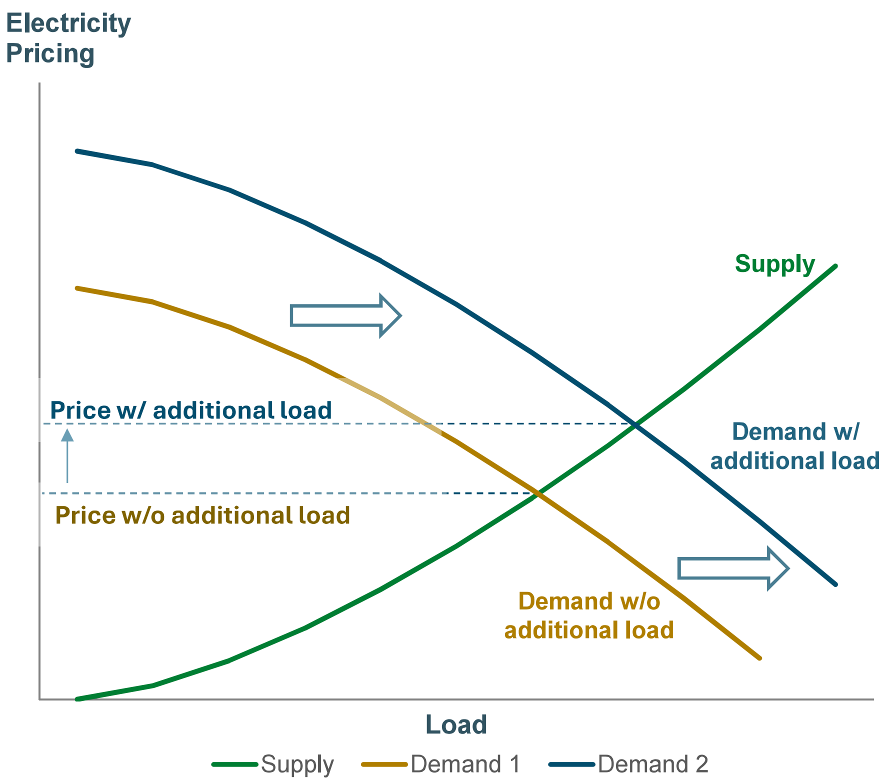
Energy+Environmental Economics

Incremental vs. Transformational Loads



Supply and Demand Dynamics in the Wholesale Market

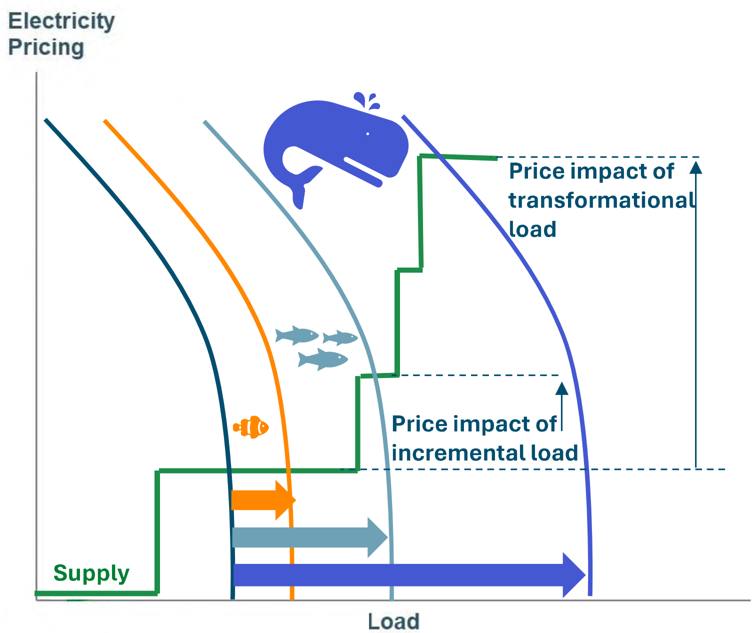
Conceptual Impact of Additional Load on Demand Curve



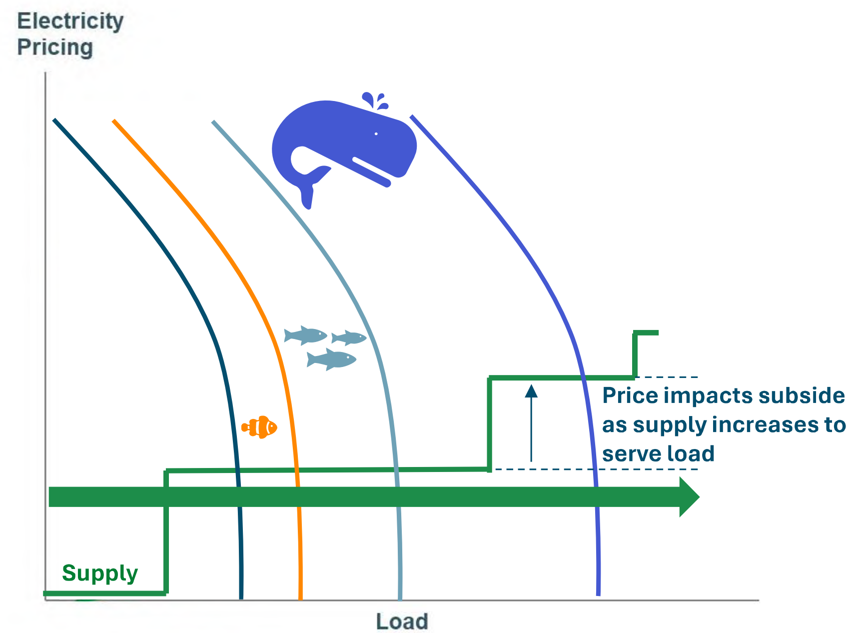
- **In a marginal cost market structure as demand increases, the demand curve shifts to the right, raising the marginal price point for supply to serve all load**
  - The supply curve is a step function dependent upon price and quantity of various resources
  - Electricity consumption is relatively inelastic; therefore, load is unlikely to contract in response to higher market prices
- **Energy costs (inclusive of capacity, generation, and environmental attributes) are expected to increase as the corresponding markets; climbing the supply curve will initially raise costs for all customers until more supply is added and the system regains equilibrium**
- **As data centers pay their 'fair share' of costs based on their contribution of load, elevated market conditions resulting from the additional demand will affect all ratepayers; this effect is not generally considered to be an explicit source of inequity between rate classes especially from the perspective of a single data center being added but in aggregate the impact can be significant**

Disruption & Reestablishment of Market Equilibrium

Illustrative Impact of Additional Load on Electricity Pricing



Illustrative Impact of Additional Supply Electricity Pricing



- Load growth in Virginia and elsewhere in PJM creates disequilibrium due to supply taking time to respond to demand signals; constraints causing lag include project development and interconnection
- Eventually, supply will respond to meet the higher load bringing equilibrium conditions and subsiding costs which will also depend on the initial "steepness" of the supply curve as well as how that supply curve shifts over time

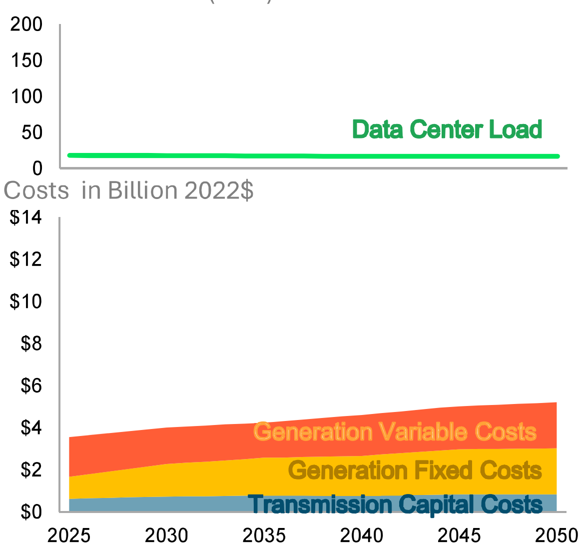
Projected Cost Impacts – Dominion

Energy+Environmental Economics

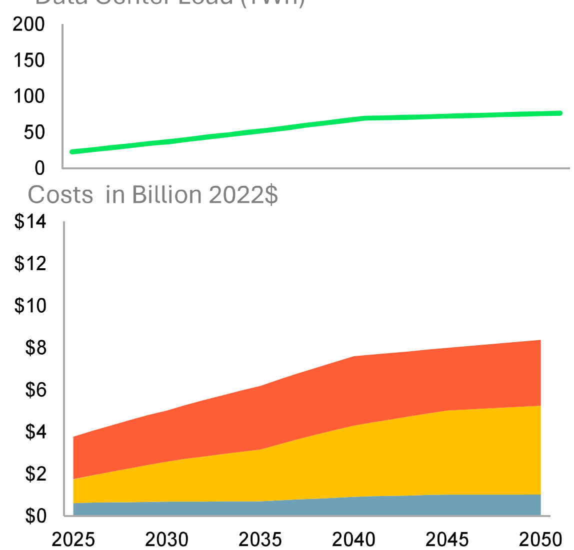
Load and Cost Projections

- Variable costs of new generation supply (inclusive of capacity, energy, and environmental attributes) are expected to increase as the corresponding markets tighten due to increasing demand relative to supply
- Generation fixed costs will increase as a result of new resources being built to meet the anticipated increase in demand
- Transmission costs are also expected to rise, as power from new resources is interconnected with growing load centers; local transmission projects and regional network upgrades and extensions for reliability and improved system efficiency will further contribute to increasing costs but are not included in this analysis.

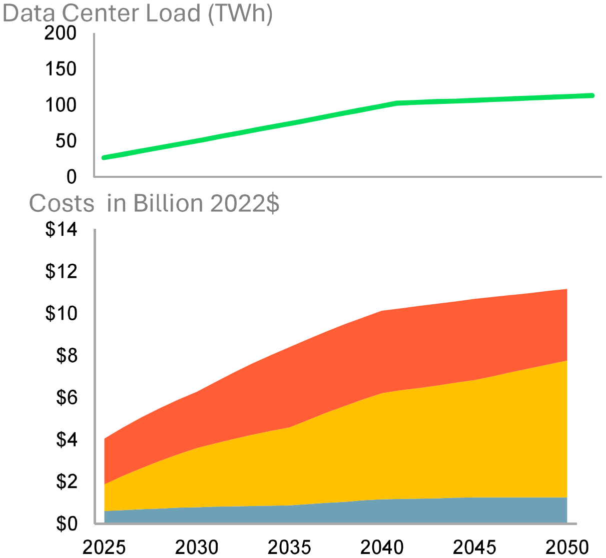
No Data Center Growth
Data Center Load (TWh)



Moderate Data Center Growth
Data Center Load (TWh)

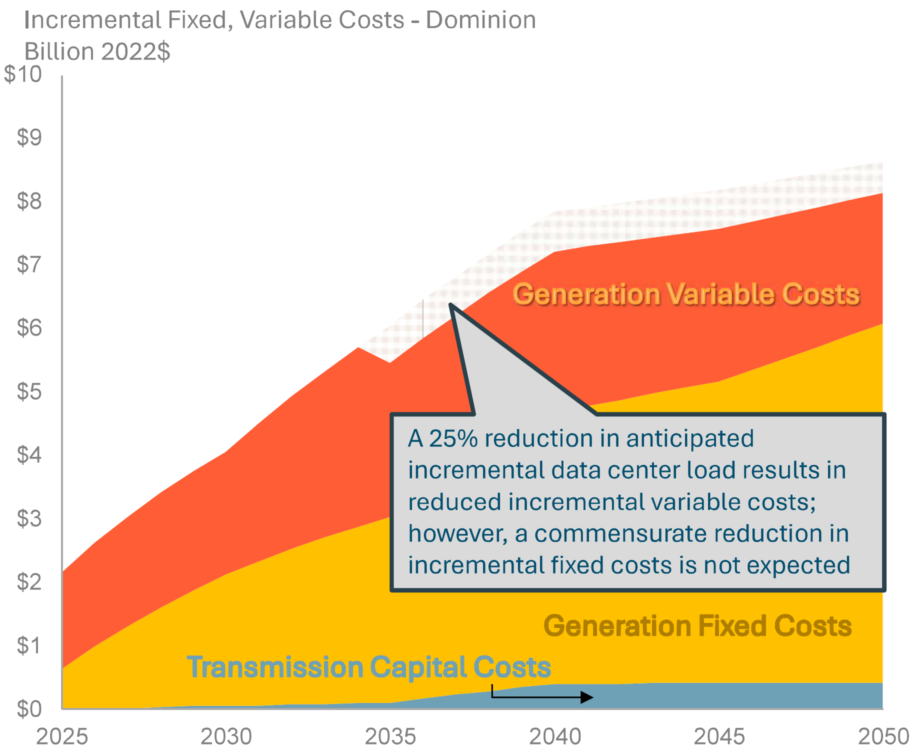


Unconstrained Data Center Growth
Data Center Load (TWh)



Cost Impacts of Underachieving Load Forecast

Unconstrained Data Center, Relaxed Policy
(25% lower incremental data center demand in 2035)

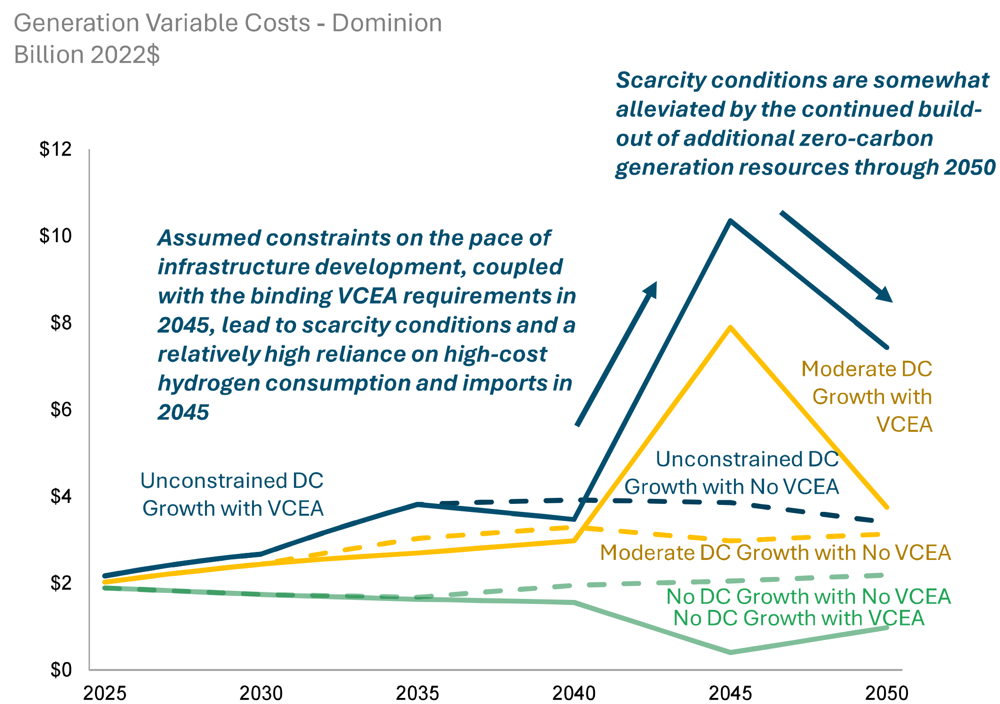


- **In a scenario where fixed costs are committed based on a data center load forecast that fails to fully materialize on time, committed fixed costs, triggered by the anticipated load, will be spread across a smaller system load, resulting in higher costs to all customers**
- **An equivalent shift in data center load to third party supply would similarly increase cost burdens to other customers, driven by the reallocation of fixed costs**

$$Retail\ Rates = \frac{(Fixed\ Costs + Variable\ Costs)}{System\ Consumption\ (MWh)}$$

Variable Costs of Generation

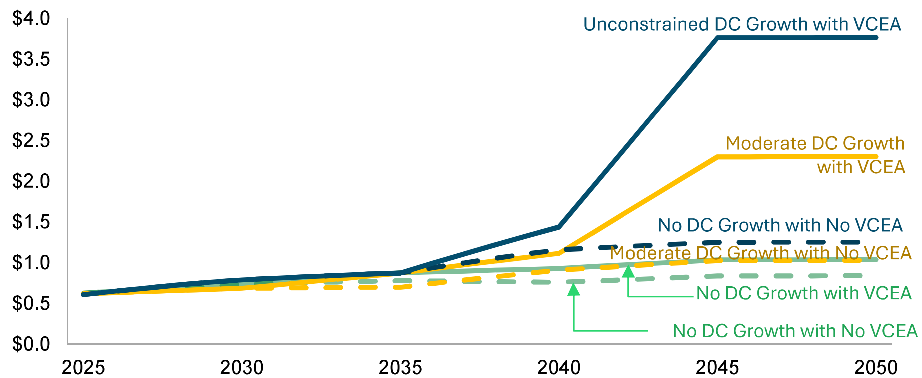
+ **Near-term surge in data center load growth is forecasted across different growth scenarios before moderating after 2040; resources used to meet demand across scenarios exhibit different cost characteristics**
  - Resources like wind, solar, and SMRs tend to have higher fixed costs with lower variable costs
  - Combustion-based resources tend to have lower fixed costs and higher variable costs
+ **Policy conditions also influences variable costs**
  - Relaxed policy scenarios see higher variable costs in early years due to more use of gas and fewer renewable resources
  - VCEA policy scenarios indicate lower variable costs in early years with increasing costs approaching 2045 as hydrogen is used to meet compliance until sufficient transmission, SMRs, and renewable resources can be developed
+ **In addition to a larger volume of generation, higher-growth scenarios are expected to result in tighter supply-demand conditions, increasing the price of energy market products and imports on a per unit basis**



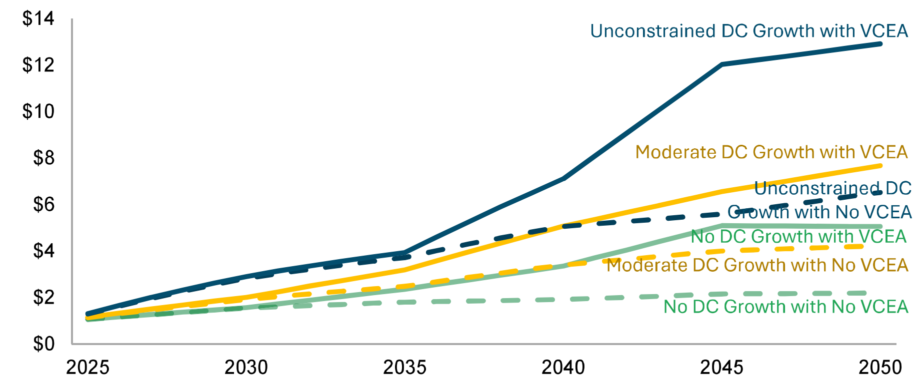
Fixed Costs of Generation & Transmission

- **Resource builds are committed in anticipation of load growth to allow for the necessary lead times for development**
- **As load growth moderates in the 2040's costs continue to climb as resource builds are brought online to meet continued demand growth and the VCEA policy requirements**
- **Policy influences fixed costs**
  - VCEA policy drives higher fixed costs due to development of renewable resources
  - Increased transmission investments is required to deliver new renewable resource builds to load centers

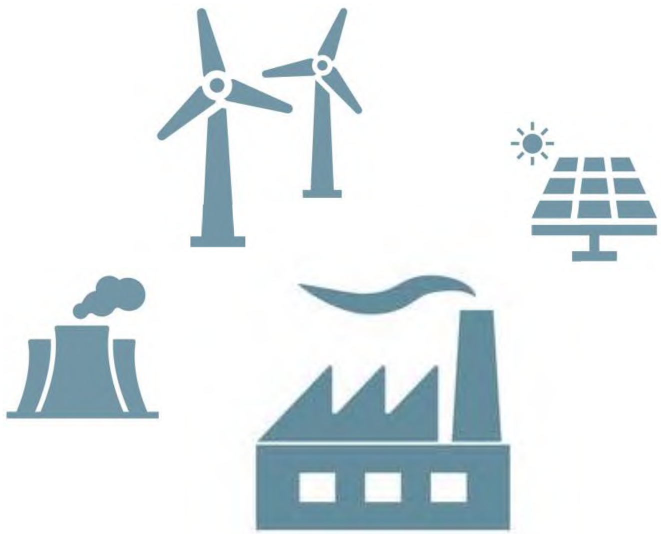
Transmission Fixed Costs - Dominion
Billion 2022$



Generation Fixed Costs - Dominion
Billion 2022$



Additional Generation Cost Considerations

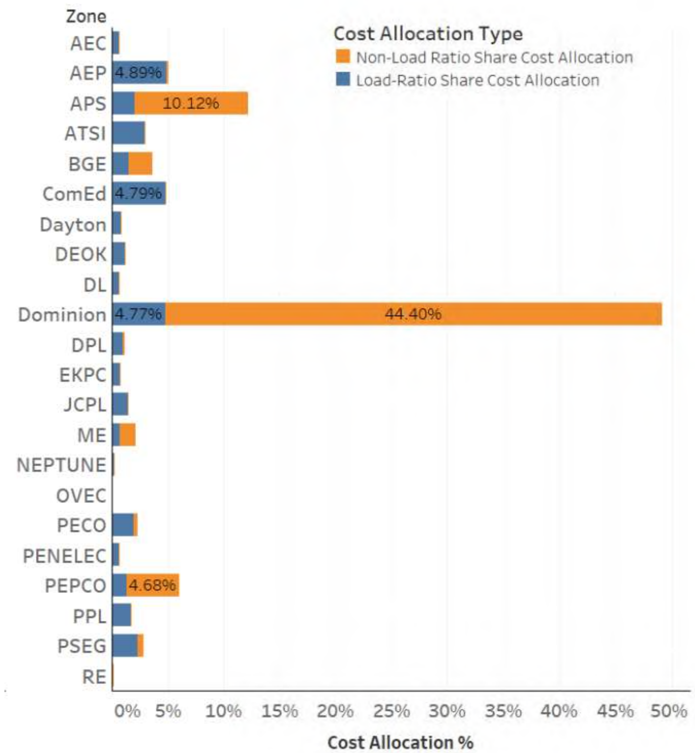


- **Generation sources and procurement method will also have cost allocation impacts, with respect to fixed and variable costs of generation; for example, a solar PPA would represent a high variable cost with no fixed costs, whereas a utility-owned combustion turbine would likely represent lower variable costs with significant fixed costs**
- **While utilities are exposed to marginal pricing in the wholesale market, retail customers typically pay average (embedded) cost, which often includes physical and financial contracts that hedge against full exposure to marginal costs**
  - There are other factors that can also mitigate ratepayer impact to higher marginal pricing such as an investor owned vertically integrated utility owning generation that is a hedge against higher market prices
- **Deviations from load forecasts could result in cost shifting under current cost allocation methodologies**
  - Data centers that outperform load expectations or operate with equipment beyond the budgeted lifespan will over contribute more to system costs
  - Data centers that underperform load expectations or that fail to reach the projected payback period of infrastructure investments made on their behalf will contribute less than an equitable amount to system costs and have a negative impact on other customers

Additional Transmission Cost Considerations

- **E3 modeling contains a high-level representation of bulk and local transmission costs to ensure new resources can be delivered to loads [see slides 122-123]**
- **However, E3 modeling does not capture local reliability constraints; the full set of transmission system needs as a result will likely be greater than projected**
  - Supplemental projects intended to improve reliability or system efficiency within the Dominion load zone would be conducted at additional costs
- **In its Regional Transmission Expansion Plan (RTEP) PJM's Transmission Expansion Advisory Committee (TEAC) identifies and recommends approximately $5 billion of additional reliability projects over the next several years**
  - These projects are not directly incorporated into E3's analysis; instead, a subset of these investments likely overlap with the identified transmission system needs in E3's modeling
  - Reliability upgrades serving a single zone are the sole responsibility of the associated transmission provider, while projects serving multiple zones are socialized more broadly across market participants and/or project beneficiaries
  - Nearly 50% of the costs associated with transmission reliability upgrades (~$2.5 billion) identified by the TEAC are prescribed for the Dominion load zone through a combination of load-share and non-load-share cost allocations
- **As the transmission provider, Dominion allocates transmission costs among load serving utilities within the transmission zone, who then recover those costs through retail rates**

Cost Allocation of Recommended Transmission Reliability Investments in PJM by Load Zone for RTEP, Window 3



Transmission Expansion Advisory Committee Recommendations to the PJM Board, December 2023. 20231205-pjm-teac-board-whitepaper-december-2023.ashx

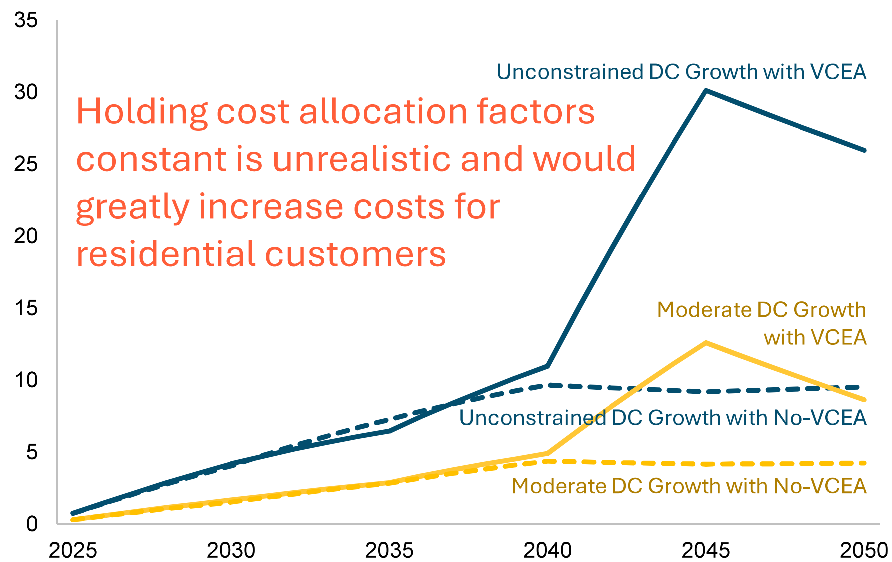
Projected Rate Impacts – Dominion

Energy+Environmental Economics

Comparative Impact of Data Center Loads on Residential Rates: Fixed Cost Allocation Factors

- **If current cost allocation factors are held consistent, Dominion's residential electric rates will experience significant upward pressure with growing data center load**
  - Note, this is not a realistic case as cost allocation factors would adjust per normal ratemaking practices, but is useful to illustrate impacts under current rates if those factors were "frozen"
- **While maintaining consistent cost allocation factors is not a realistic expectation, this perspective helps to establish an upper bound for residential ratepayer impact**
- **Distribution costs are intentionally omitted from the rate impact analysis**
  - Distribution costs incurred on the system to serve new, interconnecting loads will also increase total system cost; however, causation of these costs is more easily assessed and assigned to loads either directly (upfront) or indirectly (cost allocation)
  - Data centers are increasingly interconnecting at transmission voltages and contributing less to distribution network costs

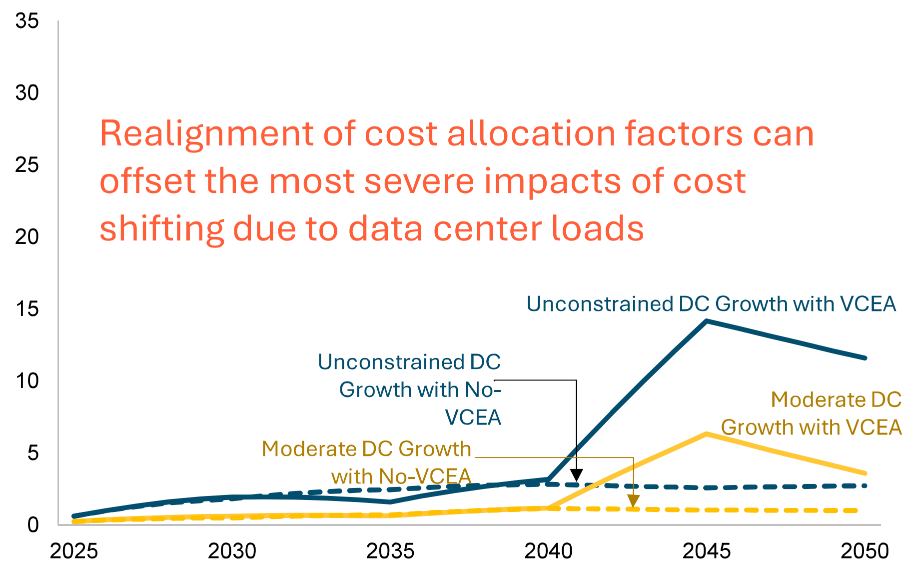
Average Residential Rate Impacts - Dominion
(Fixed Allocation Factors)
cents/kWh (2022$)



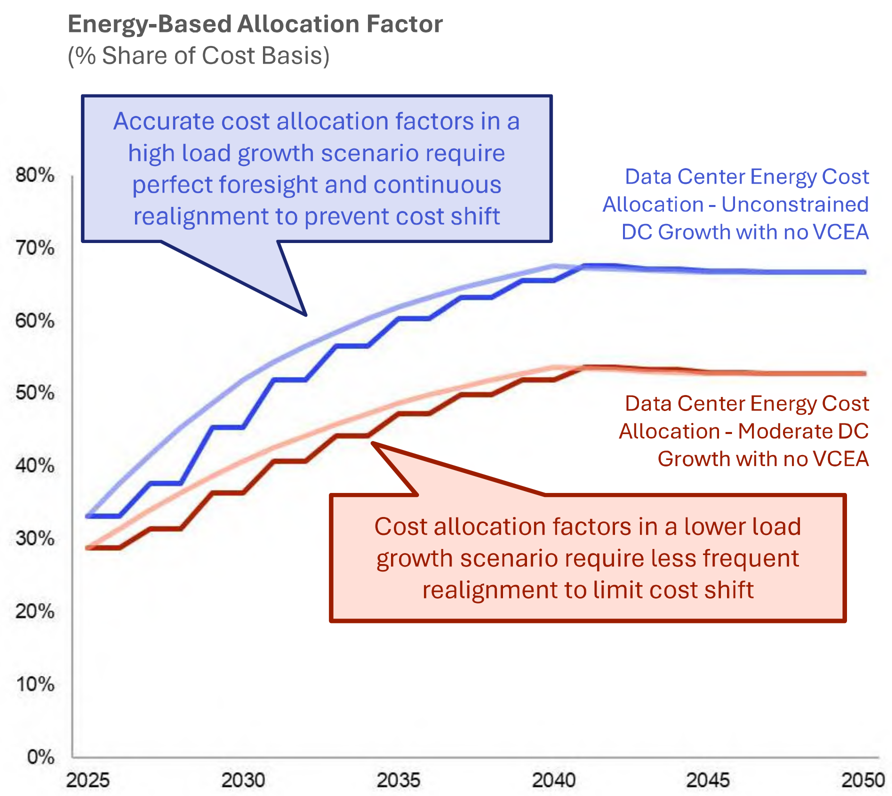
Anticipated Impact of Data Center Loads on Residential Rates: Updated Cost Allocation Factors

- **Cost allocation factors can be updated using current methodologies, which assess contributions of each rate class toward total system demand and consumption**
- **Growth forecasts were used to estimate new cost allocation factors for the residential rate class, showing a necessary reduction by about half by 2050 under the most aggressive growth scenarios**
  - Residential customers currently account for 37% of energy consumption and 51% of demand
  - Under the conditions of projected data center growth, the contribution of residential customers to system consumption and demand could fall to as low as 17% and 33%, respectively by 2050
- **Ideal realignment of cost allocation factors can inform a lower bound for residential ratepayer impact**

Average Residential Rate Impacts - Dominion
(Adjusted Allocation Factors)
cents/kWh (2022$)

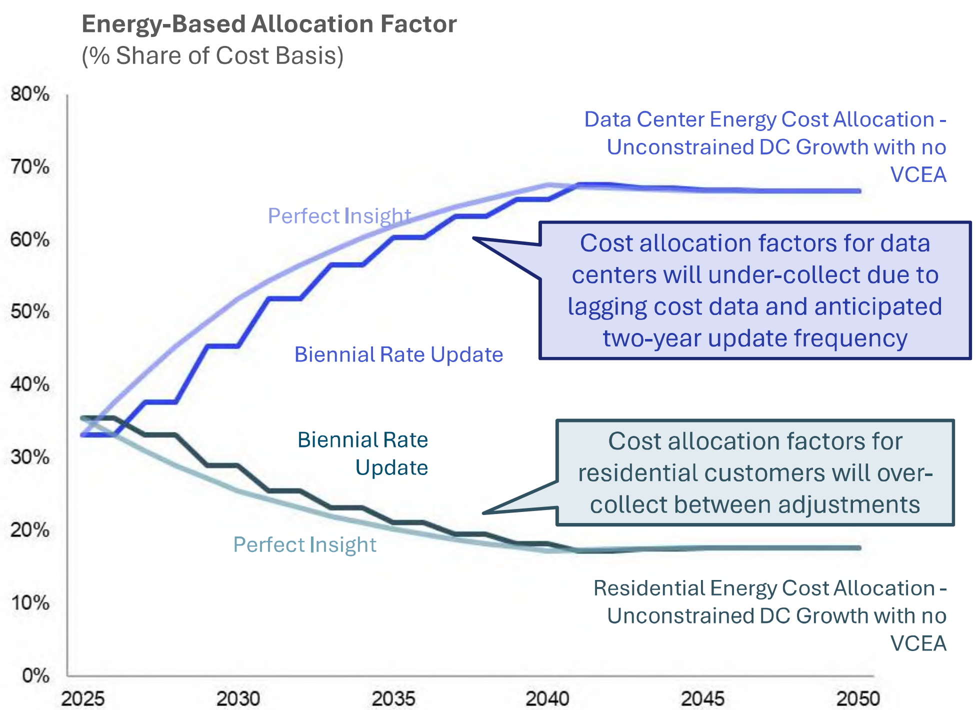


Influence of Regulatory Lag: Scenario Comparison



- **Current practices for realigning cost allocation factors are likely insufficient for keeping pace with anticipated rate of load growth**
  - Those practices were not designed to account for this level and continued pace of large load growth from essentially a single customer type
- **Introduction of new resource costs and load growth between rate reviews will meaningfully change the allocation of portfolio costs**
- **The Virginia SCC reviews cost allocation factors for Dominion every two years; while historically, this has been sufficient to address incremental load growth, the pace and magnitude of data center growth is likely to require reconsideration of this approach.**

Influence of Regulatory Lag: Rate Class Comparison

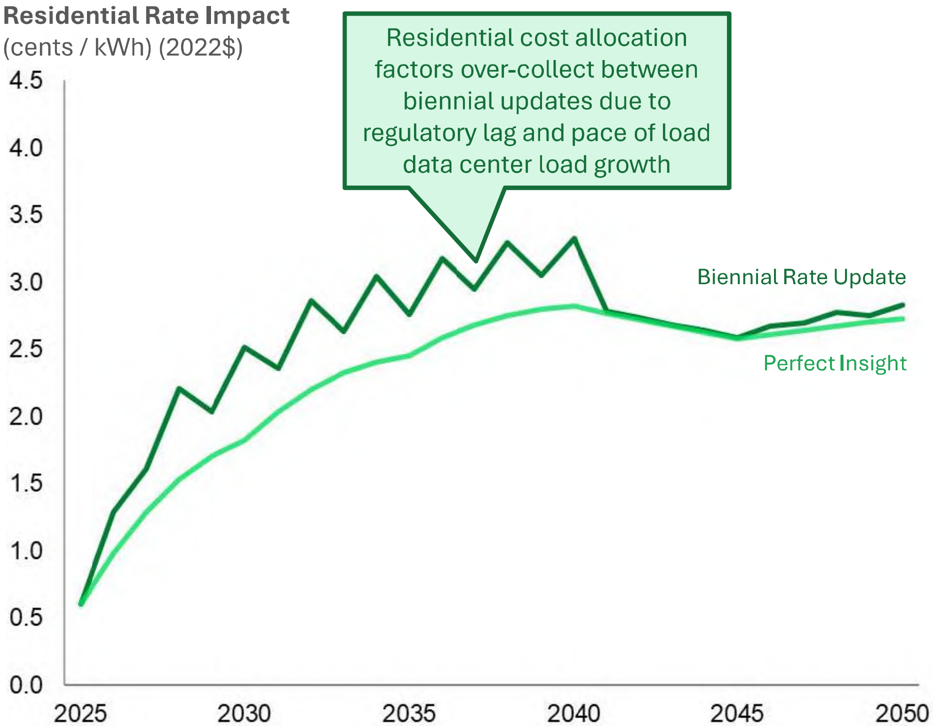


+ **Best efforts to realign cost allocation factors are still likely to lag costs due to regulatory process and inaccuracies of forecasted data**
+ **Such regulatory lag may shift costs away from data centers until associated load growth moderates**
  - Realignment of data center cost allocation factors is expected to increase over time, as their contribution to system consumption and demand grows; periods between cost allocation adjustments will favor data centers
  - Realignment of residential cost allocation factors is expected to decrease over time, as the class contribution to system consumption and demand falls, relative to data centers; periods between cost allocation adjustments will disadvantage residential customers

Influence of Regulatory Lag: Potential Rate Impact

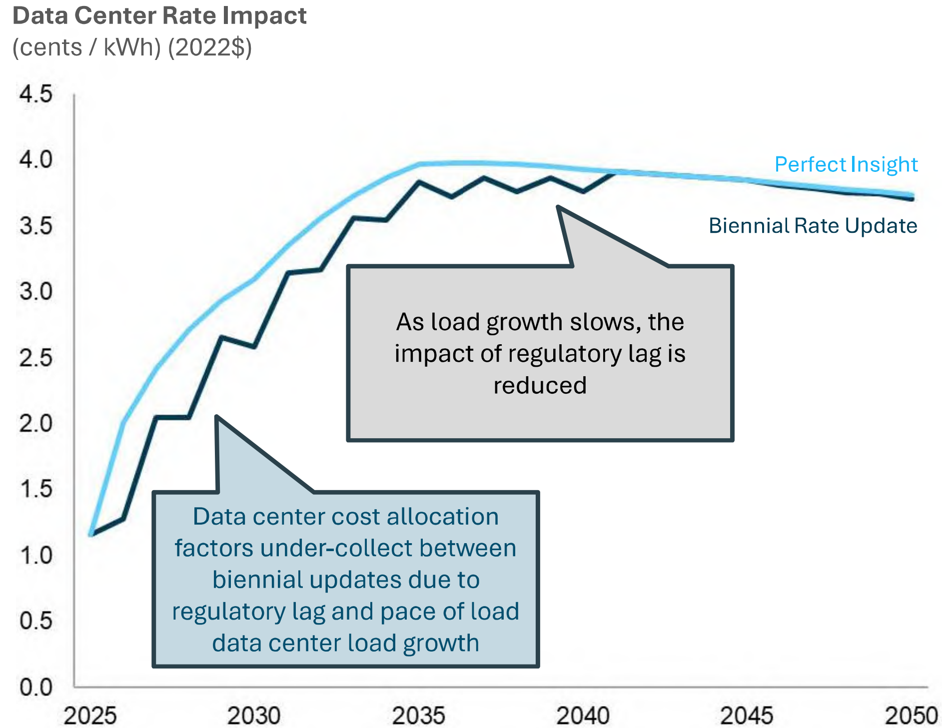
Influence of Regulatory Lag on Residential Rates

Unconstrained DC Load Growth, without VCEA



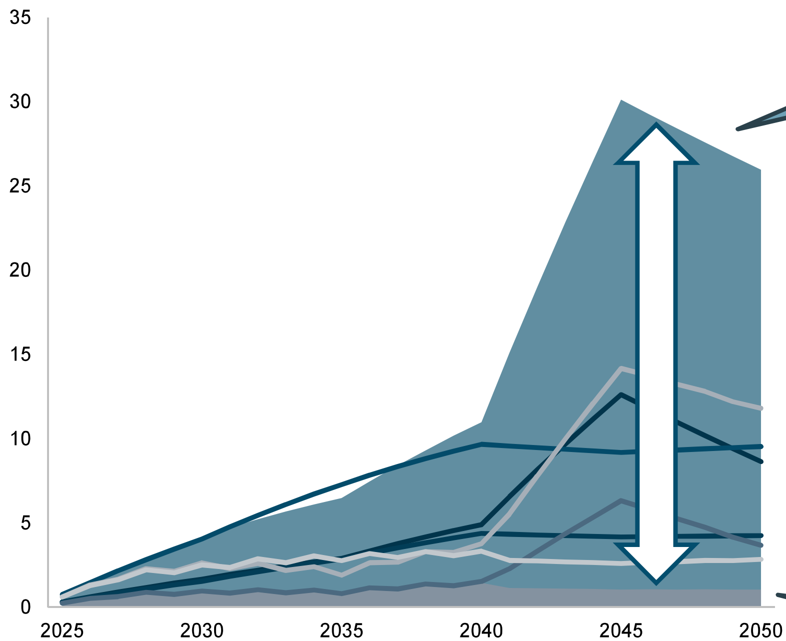
Influence of Regulatory Lag on Data Center Rates

Unconstrained DC Load Growth, without VCEA



Range of Potential Impacts

Range of Anticipated Residential Rate Impacts for Dominion Virginia
cents/kWh (2022$)



Upper boundary assumes no adjustment of cost allocation factors, which is not realistic, but shown for illustrative purposes

- **Range of possibilities is influenced by several factors:**
  - Data center growth rate
  - Cost allocation adjustments
    - Where applicable, periodic adjustment of cost allocation factors is anticipated to occur as required by the Commonwealth of Virginia
  - VCEA policy
- **Rate impacts correspond only to those from incremental data center load; other cost increases are expected**
- **Rate impacts stabilize as the load forecast levels, but effects will persist beyond load growth**

Lower boundary assumes perfect foresight and real-time adjustment of cost allocation factors, which is not practical

Residential Rate Impact
Dominion Utility – *Example Bill*

Billing Details
Learn more at DominionEnergy.com/YourBill.

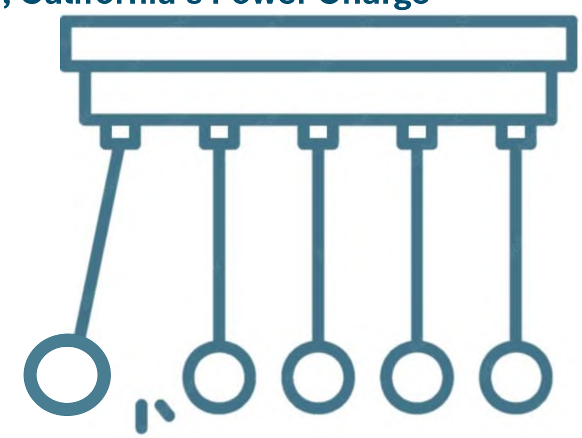
Electric Charges and Credits	
Previous Electric Charges and Credits	
Previous Balance	120.32
Payment Received	120.32 CR
Balance Forward	**0.00**
Current Electric Charges and Credits	
Residential (Schedule 1)	***03/02-04/02***
Distribution Service Charges	**30.37**
Electricity Supply Service (ESS)	
Generation	41.31
Transmission	12.14
Fuel	22.27
Electricity Supply Charges	**75.72**
Deferred Fuel Cost Charge	2.40
PIPP Universal Service Fee	0.57
Sales and Use Surcharge	1.75
State/Local Consumption Tax	1.22
City / County Utility Tax	2.00
Taxes, Fees and Charges	**8.59**
Current Electric Charges	**114.68**
Account Balance	**114.68**
Amount Due	**$114.68**

- **Incremental allocations and associated rate impacts on residential costs of transmission and generation resulting from investments supporting data center growth are expected to increase, on average, by over 12% annually through 2050, putting upward pressure on residential utility bills for Dominion customers**
- **Under the Unconstrained Data Center Growth with VCEA scenario, associated transmission and generation costs would increase the average bill for a Dominion residential customer, in real terms, from $114.68/month today to $139.37/month by 2050**
  - This increase is independent of cost impacts resulting from distribution upgrades, transmission reliability investments, or inflation
  - Assumed consumption is with 779 kWh/month of usage

https://www.dominionenergy.com/-/media/images/virginia/billing/bill-redesign/new-va-res-same-customer-example

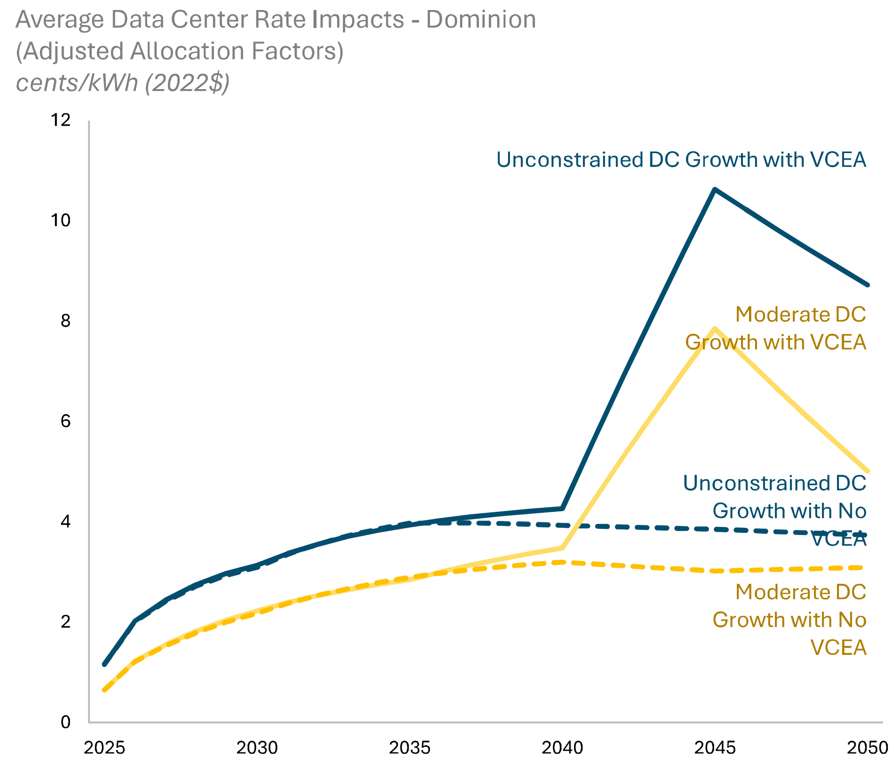
Additional Cost Influences

- The significant investments required by utilities to serve the anticipated data center loads are potentially likely to put pressure on both 1) their ability to raise capital from markets and 2) the cost of that capital, which would directly impact rates although that impact could be mitigated with de-risking certain data center related investments
- Renewable accelerated buyers program may promote acquisition of renewable energy from outside Virginia, which would likely alleviate some pressure on the price of in-state RECs required for VCEA compliance
- Retail choice has potential to result in stranded costs if large loads elect to transition away from bundled energy supply from their utility; though a five-year commitment period reduces volatility, a mechanism to hold customers responsible for fixed costs of generation incurred on their behalf prior to departing for a retail choice provider may help to ensure customers remain indifferent to such decisions of large loads (e.g., California's Power Charge Indifference Adjustment (PCIA) serves as one example of this approach)
- Increasing load density is likely to raise locational marginal price (LMP) in areas of higher need and constraint; utilities with high exposure to import markets will experience a commensurate upward pressure on energy prices until markets adjust and reach a new equilibrium due to increased demand



Data Center Rate Impacts

- **Data centers bear a greater financial burden than residential customers for the economic impacts of data center development under existing rate structures**
  - Data centers are projected to experience an increase in 3-4 cents/kWh by 2040, compared to an estimated increase of 1-3 cents/kWh for residential customers
- **The same economic pressures influencing residential rates are likely to have similar impacts on data center rates**
  - Data centers are expected contribute three-to-seven times more toward incremental costs than residential customers by 2050
  - Total incremental cost contributions from data centers are anticipated to range from $2-$10 billion by 2050, depending on scenario



Future Rate Equity Considerations

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Narrow Path to Equitable Outcome Under Existing Rate Structures

Transformational load growth is unlikely to benefit other ratepayers under current rate structures

+ **Data centers are unlikely to produce downward pressure on rates until load growth stabilizes, and system equilibrium is regained, which is expected to extend beyond 2040**
+ **Fixed cost impacts are expected to endure beyond the surge in data center development as resource additions and associated costs lag load growth**
+ **Deviations from forecasts will exacerbate different cost concerns**
    - Failure of data center loads to fully materialize as forecasted will reduce the diffusion of fixed costs across system load, increasing upward pressure on rates for existing customers
    - Accelerated or increased data center load will further tighten marginal cost markets, exacerbating the upward pressure on variable generation costs for existing customers
+ **Failure to update cost allocation factors in an accurate or timely manner will produce inequities**

Expanding the Path to an Equitable Outcome

Various tools can help manage risk and widen the path to equitable integration of data center loads

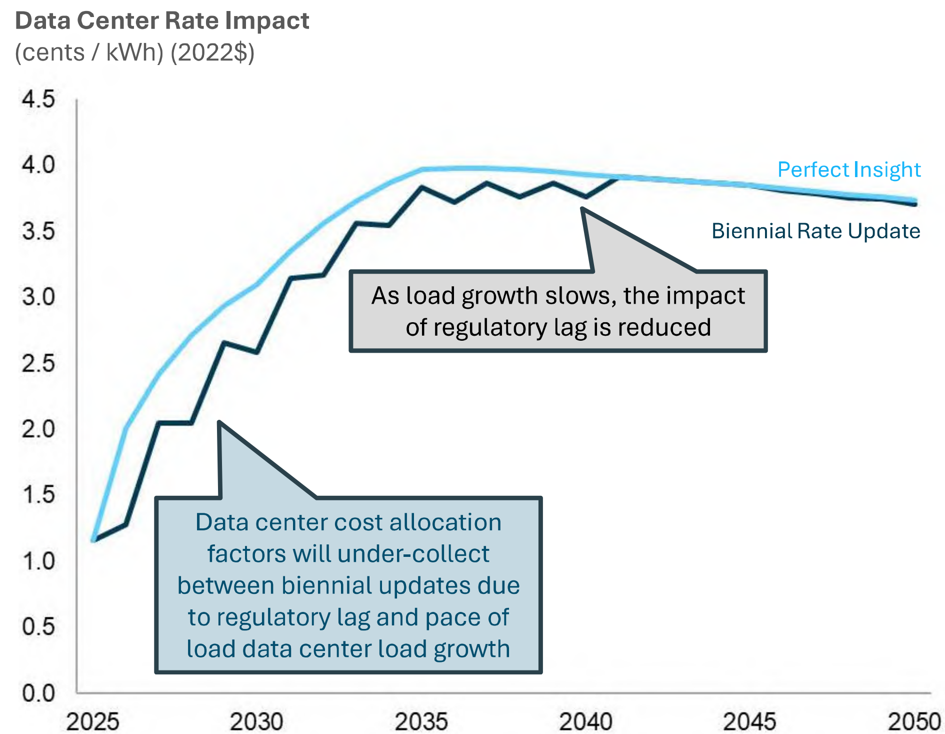
+ Updating cost allocation factors and reducing regulatory lag given pace and scale of data center load growth
+ Additional charges for data centers that balance historical ratemaking for individual large loads and potential impacts of transformational load growth
+ Better forecasting of data center demand, which can also include a waitlist for service and other load interconnection queue reforms
+ Long-term service commitments that may include ramping provisions, exit fees, and/or minimum terms for energy and demand charges such as "take or pay" constructs
+ Self supply of resources or "bring your own generation" of both existing and emerging technologies like SMRs along with leveraging continued innovation from data center companies on energy efficiency as well as flexible operations
+ Direct assignment of new infrastructure costs as well as enhanced collateral / credit requirements

Rate Impact Toolkit: *Updating Cost Allocation Factors*

- **Improving processes for updating cost allocation factors may help mitigate the potential for cross-subsidization between classes due to regulatory lag**
  - More frequent adjustments could help to maintain more accurate apportioning of costs
  - Automatic adjustments, within an approved framework and subject to periodic review, could enable utilities to keep pace with rapid load growth
- **Reducing oversight and regulation of cost allocation factors may introduce risk due to the magnitude and frequency of adjustments that are likely to be required**

Influence of Regulatory Lag on Data Center Rates

High DC Load Growth, without VCEA



Rate Impact Toolkit:
Additional charges for data centers

Inclusion of a surcharge for associated data center rates would recover additional contributions to embedded costs and could be set to offset indirect costs incurred due to data center load and to guarantee a net benefit for existing customers

If data centers were to be mostly or fully assigned costs incurred on the system on their behalf, existing customers would be insulated from many of the direct cost impacts

Excessive contributions by data centers, above marginal cost, could be viewed as discriminatory and may stifle new data center development

Marginal Costs	New Costs	Contribution to Fixed Costs
Data Centers must pay at least their marginal costs of service to avoid shifting the burden inequitably to existing customers	**New costs could be direct (e.g., administrative) or indirect (e.g., network upgrades) and may be difficult to quantify or assign**	**Contributions by data centers to system fixed costs benefit existing customers; however, excessive contributions are inequitable to data centers**

Rate Impact Toolkit:
Data Center Interconnection Queue Management

- To reduce risks associated with forecast error and potential stranded assets, a "wait list" of data centers could be developed to take the place of any data center that ceases operation
- Given Virginia's unique position as the premier data center market, other data center customers may be likely to take the place of a load that fails to materialize or one that exits the market prematurely
- Assets would have higher assurance of being fully and consistently utilized if new data center loads were actively waiting for opportunities to take over any load that drops out or is not meeting certain development milestones

Image generated with AI

Rate Impact Toolkit: Service Commitments

- **Recent settlement agreements across diverse stakeholders including data center companies filed with regulators in Ohio and Indiana aim to address provisions for interconnecting large data center loads**
- **The proposals contains several key elements that address concerns over committed fixed costs**
  - Minimum payment threshold requires data centers to pay for a percentage of their projected energy needs upfront
  - Contractual obligations mandate extended contract terms with exit fees for data centers that cancel projects early
  - Focus on consumer protection ensures that data centers contribute adequately to grid upgrades needed to serve them
- **While the concept has shared support from a wide variety of stakeholders, disagreement over the specific terms and rates has led to two competing proposals to be filed with the PUC**
  - Advocates for proactive management of data centers growth include:
    - Utilities
    - Regulatory staff
    - Ratepayer advocates
    - Traditional industry representatives, like Walmart
  - Some data center developers and energy suppliers are advocating for similar, but more modest terms to balance their perceived risk such as the utility failing to interconnect them on schedule

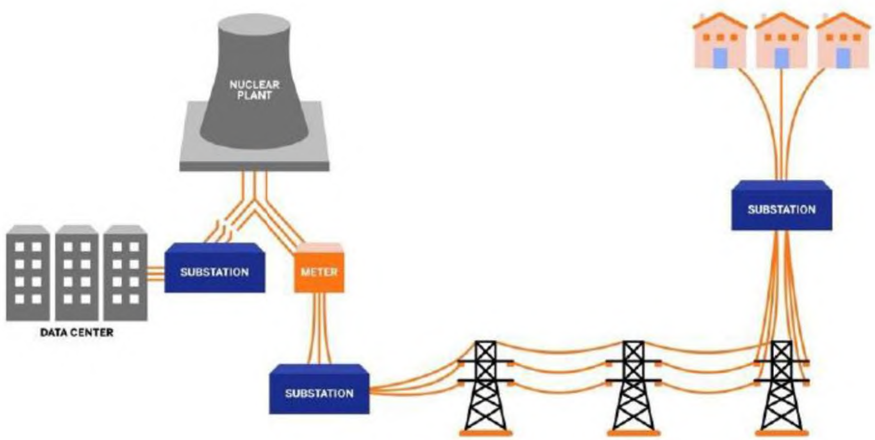
One proposal would require new data center customers to pay a minimum of 85% of the contracted capacity, regardless of actual demand or consumption. Such a commitment would be in place for 12 years, including a 4-year ramp up period.[1]

[1] AEP Ohio, PUCO Staff, Ohio Consumers' Counsel, Ohio Energy Group and Others Agree on How to Address Growing Data Center Power Needs
PUCO case no. 24-508-EL-ATA, Joint Stipulation And Recommendation. https://dis.puc.state.oh.us/

Rate Impact Toolkit: Self Supply of Resources

Data centers have several options for procuring their own resources:

Co-location: On-site generation is the primary power supply for the data center with direct, bilateral agreements between the power developer and the data center owner/operator



Power Purchase Agreement (PPA): Agreement between data center and power supplier within the same service territory with utility acting as an intermediary

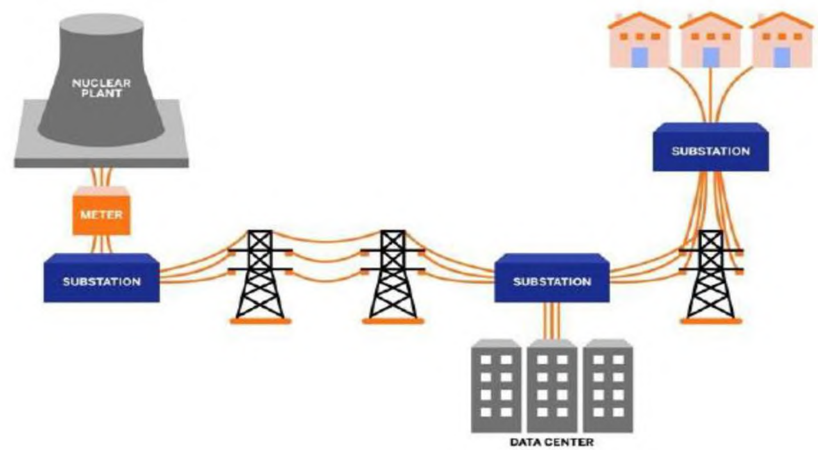


Figure source: Kormos, Michael, The Co-located Load Solution, July 2024. https://ferc.gov/libraries/

Benefits and Concerns of Self Supply

- The concept of "bring-your-own-generation" ("BYOG") has gained recent interest by data center developers and utility regulators
- In March 2024, Talen Energy sold its data center campus linked to the Susquehanna Nuclear Station in Pennsylvania to Amazon Web Services with a 10-year power purchase agreement for up to one-third (960MW) of the facility's total capacity to be delivered directly to the data center; the amended interconnection agreement was subsequently rejected by FERC in November 2024
- FERC held a technical conference in November 2024 to begin addressing the issue of co-location of data centers with generators
- FERC, PJM, and many other stakeholders including utilities and data center companies are continuing to actively explore the issue of data centers co-locating with generation, with additional guidance anticipated

> "Co-location arrangements of the type presented here present an array of complicated, nuanced and multifaceted issues, which collectively could have huge ramifications for both grid reliability and consumer costs"
>
> –FERC Commissioner Mark Christie

Susquehanna Nuclear Plant and Data Center

Photo: Talen Energy

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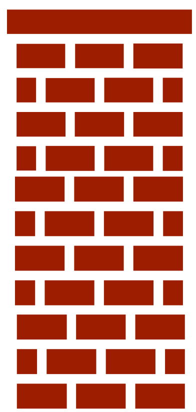
FERC Docket No. AD24-11-000, October 2024. https://www.ferc.gov/news-events/events/commissioner-led-technical-conference-regarding-large-loads-co-located
PJM Guidance on Co-Located Load. April 2024. https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/pjm-guidance-on-co-located-load.ashx

Rate Impact Toolkit:
Direct Assignment of Costs

- Mitigating the cost impacts of extreme load growth for existing general service customers may warrant isolating data centers and directly assigning costs
- Resource portfolios would effectively be separated with costs sourced through energy service agreements or otherwise acquired exclusively to serve data center load
- Insulating existing customers from data center customers provides downside protection, but also limits opportunity for the potential upside impacts like margin sharing, clean energy generation acceleration, or long-range diffusion of fixed costs over time
- Historically public power utilities use this technique more frequently than investor-owned utilities primarily due to business model differences and other factors

General Service Customers

Cost Component	Cost Recovery
Energy Capacity Ancillary Services RECs Embedded Fixed Costs Administrative Costs Interconnection Costs	Embedded Cost



Data Center Customers

Cost Component	Cost Recovery
Energy Capacity Ancillary Services RECs	Marginal Cost
Embedded Fixed Costs	Fixed Cost Adder
Administrative Costs Interconnection Costs	Directly Assigned

Indirect influences unable to be effectively measured and assigned based on cost causation would continue to be socialized putting upward pressure on costs for all utility ratepayers

- Utility bond rating
- Marginal cost markets
- Locational marginal pricing

Rate Impact Management: Spectrum of Rate Design Tools

	Promotes Data Center Growth	Protects Existing Customers	Potential Benefits for Existing Customers	Relative Ease of Implementation
Fully Embedded Rate Structure (Current Methodology)				
Cost Allocation Adjustments				
Additional Charges for Data Centers				
Waitlist for Service				
Service Commitments				
Self Supply of Resources				
Direct Assignment of Costs				

Additional Considerations

- If data center loads are constrained or discouraged in Virginia, they may take root elsewhere in PJM, which would likely have similar generation and transmission marginal cost rate impacts without the associated local economic development
- In some cases, the resource development and network upgrades required to serve increasing data center load may be an *acceleration* of improvements that would otherwise be warranted, not necessarily an outright addition such as the needed rebuild of an aging grid as well as the need to expand the grid for successive waves of load growth such as from electric vehicles, building electrification, and advanced manufacturing
- Load growth, led by data centers, will likely accelerate the development of clean energy resources due to their preferences along with developing new energy resources such as first-of-a kind technologies that traditional utilities and customers cannot easily support which can spur more rapid innovation and improved cost efficiencies, unlocking long-term benefits to all consumers
- In a scenario where data center growth is low or lower than expected and native load growth is high, due to electrification of building and transportation sectors and/or other new industrial loads, the additional load from data centers would help diffuse those native load driven incremental fixed costs which could potentially put downward pressure on rates
- The addition of stable loads and beneficial system upgrades prompted by data centers will likely provide a long-term advantage for all consumers once load growth eases, fixed costs are recovered, and market pressure subsides

Recommended Improvements to Utility Retail Rate Design

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Recommendations

Dominion

- Cost recovery exposes the utility and its other rate payers to risk if data center does not fully subscribe or fails to operate for sufficient time to collect full system investment through allocations
- Adjustment of cost allocation factors should be made more frequently to mitigate cost shifts due to regulatory lag
- Data centers represent an industry with sufficient size and unique attributes (e.g., load factor) to likely warrant separate rate class; comingling different industries at this scale unnecessarily complicates the process of fair and equitable allocation of system costs, especially for other industrial customers with other needs and operating patterns who are served under the same class.

MEC

- A tailored approach seeks to assign all costs incurred by the Cooperative's only data center to the customer directly. This approach likely underutilizes the infrastructure, reducing system efficiency and placing sole onus on data center customer, rather than having opportunities for shared costs and resources among several customers
- While very effective at insulating costs between rate classes, MEC's tailored approach to its data center customer is so prescriptive that expansion from a single customer to a class of customers is not realistic under the existing structure; therefore, unless a more flexible framework is implemented, future data center customers will require their own unique rate designs, which may be seen as impractical or discriminatory

NOVEC

- There are limited updates to its cost-of-service study on file with the SCC; more frequent reviews would help to ensure that assumptions and cost recovery methods are maintained well-calibrated with growing data center loads

General

- Leveraging on-site generation during peak loads via a demand response program or interruptible (non-firm) rate could help reduce fixed costs associated with building and maintaining additional system capacity; a variance measure was proposed by Virginia's Department of Environmental Quality in 2023, which would authorize such action, but it was eventually cancelled for lack of customer interest

Appendices

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Appendix Contents

Appendix A: Methods and Inputs

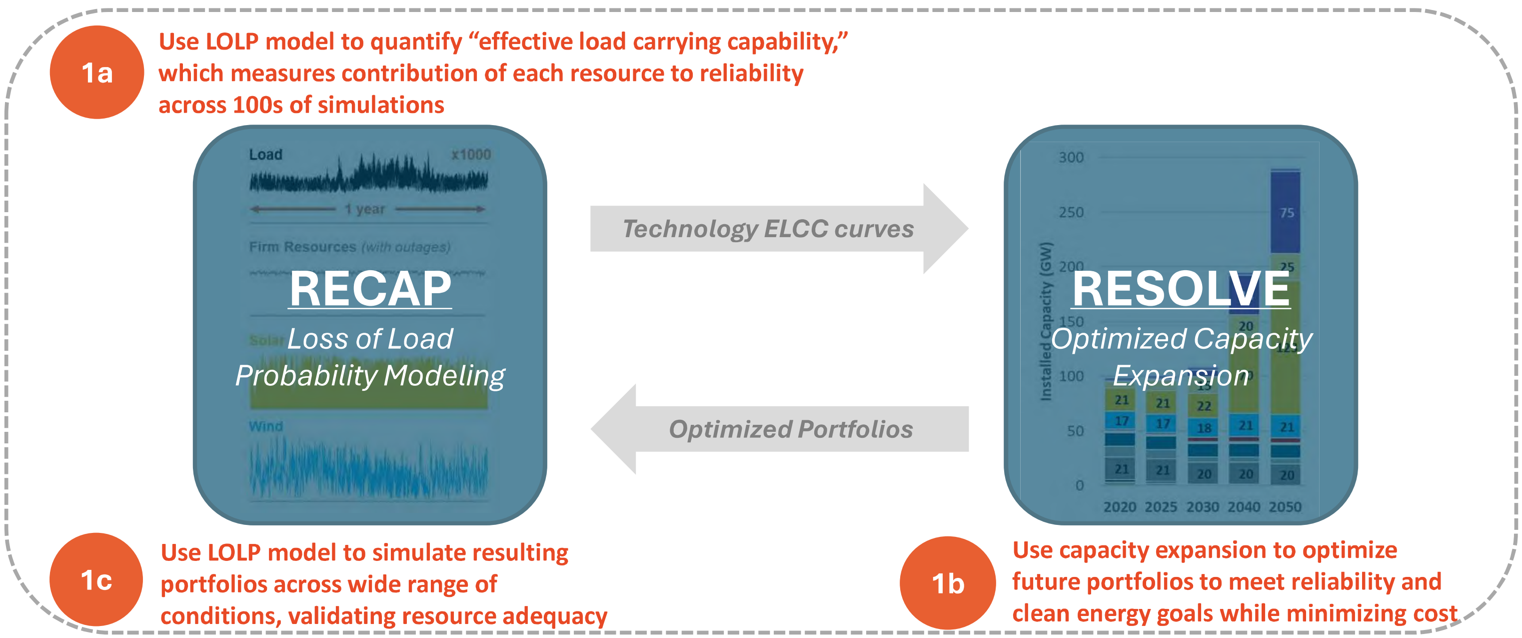
Electric Infrastructure Study Overview

Key Objective of Infrastructure Analysis: Examine electricity system infrastructure and associated investments required to meet the VCEA goals under a wide range of potential data center-driven load growth scenarios

To perform this work, E3 leveraged a ***capacity expansion model*** *in tandem with a* ***loss of load probability model****, in order to ensure the resulting portfolios are reliable over a broad range of weather conditions.*

E3 modeled the entire PJM region within its capacity expansion framework to allow more detailed examination of the interaction between Virginia and the broader market in the context of rapid data center growth. However, by design we did not model the PJM market construct precisely in terms of price formation of energy and capacity prices.

This analytical framework identifies the total infrastructure requirements but does not distinguish between utility-owned infrastructure vs. 3rd party owned vs. "behind-the-meter" generation at data center facilities.



RECAP: Loss-of-Load Probability Modeling to understand grid reliability needs

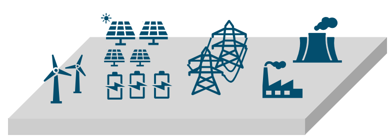
- **RECAP is a loss-of-load-probability model developed by E3 to study the reliability dynamics of high-renewable electricity systems**
- **RECAP simulates the operations of the electricity system under thousands of scenarios to capture different conditions**
  - Including load variability, weather variability, renewable output variable, forced outage events
- **Key RECAP outputs:**
  - System reliability
  - Target planning reserve margin
  - Capacity need shortfall
  - Capacity value of resources

Temperature and Load Artificial Neural Network Simulation

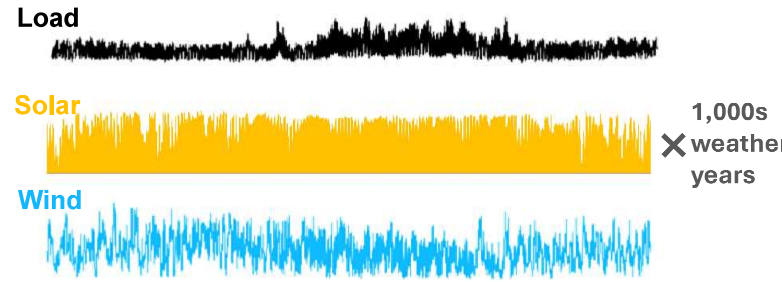
Capturing hourly load conditions under mild and extreme historical weather

Operational Module

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

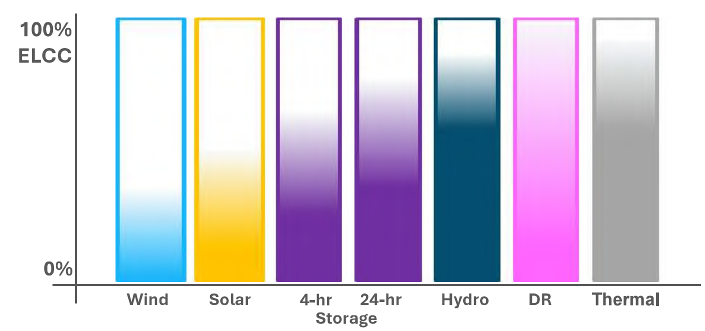


System Reliability: simulates the operations of the electricity system under thousands of scenarios to capture different conditions



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

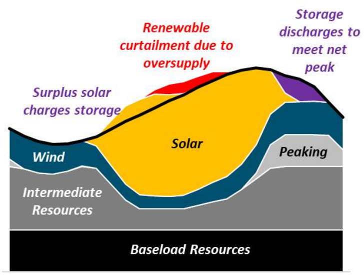
Illustrative ELCC Values Across Technologies



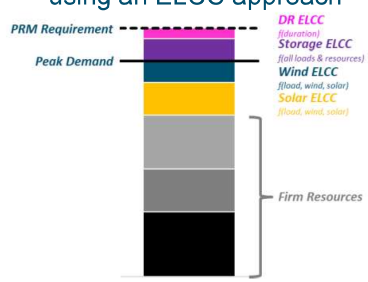
RESOLVE Model Overview

- **RESOLVE is a linear optimization model explicitly tailored to study of electricity systems with high renewable & clean energy policy goals**
- **Optimization balances fixed costs of new investments with variable costs of system operations, identifying a least-cost portfolio of resources to meet needs across a long time horizon**

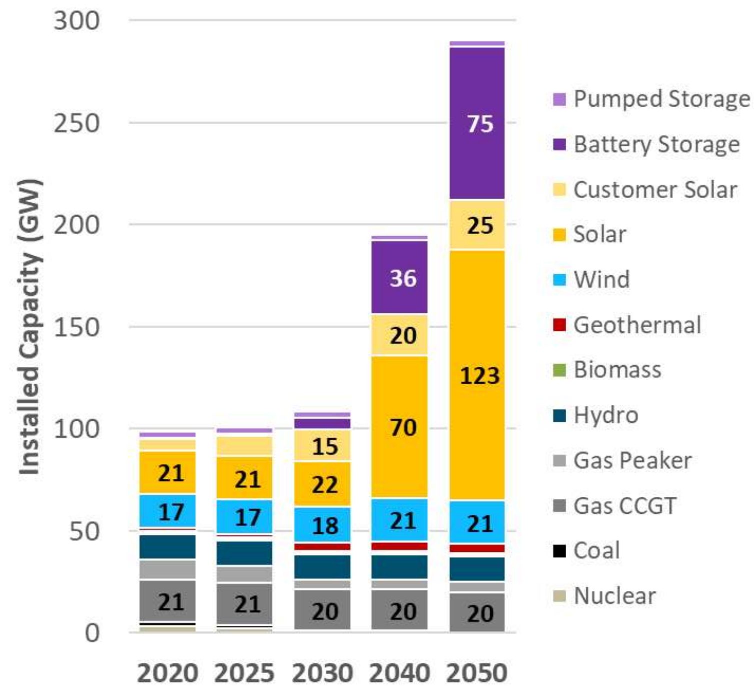
Operational module simulates hourly system operations for a sample of representative days



Reliability module ensures portfolio can meet load during extreme conditions using an ELCC approach



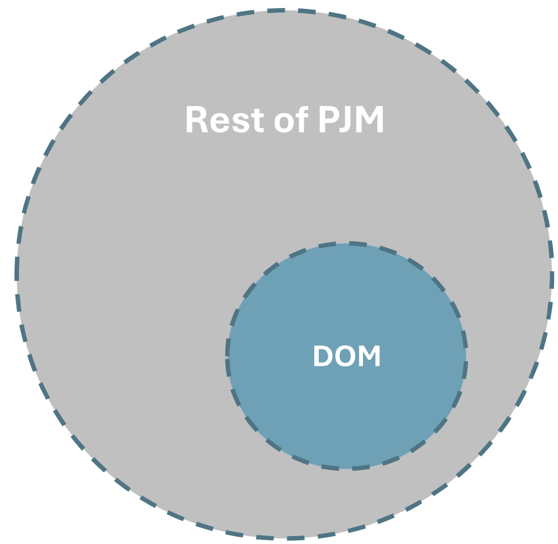
Least-cost plan co-optimizes investments and operations to meet clean energy policy targets, selecting from a diverse set of potential resources including wind, solar, storage, DSM, and natural gas, etc.



Example RESOLVE result from *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California* (Calpine, 2019)

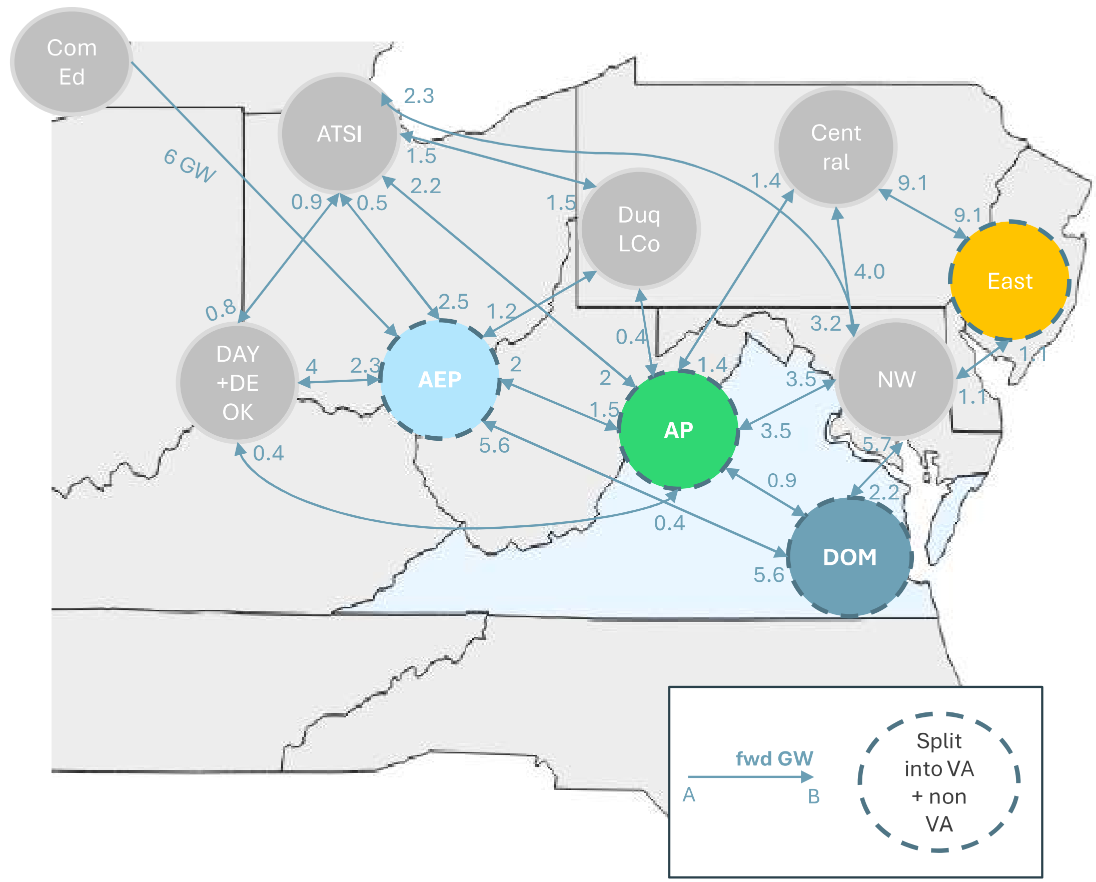
Model Topology and Scope for RECAP

+ **E3 estimated the evolution of system reliability need using RECAP for (1) DOM transmission zone and (2) the entire PJM**
  - Benchmarked to current planning reserve margin constructs, the effective capacity needs for maintaining a reliable system were set for future years through 2050 and under each data center growth scenario
+ **E3 produced resource Effective Load Carrying Capability (ELCCs) for existing and candidate future resources**
  - Resource ELCCs for DOM are used to reflect the specific resource adequacy constraints with increased data center load and renewable build-out in that area
  - Resource ELCCs for PJM are used for all other zones modeled in RESOLVE
  - The ELCC approach was also later used to estimate the reliability contribution of potential data center load flexibility
+ **This approach ensures that both the DOM transmission zone and the entire PJM region will meet the reliability criteria (1 day in 10 year loss-of-load expectation, i.e., 0.1 LOLE)**
  - The ability to access the capacity market is still present for the DOM transmission zone, but this construct ensures most of its capacity requirements are met internally



Capacity Expansion Topology

+ **E3 modeled capacity expansion for the PJM market in RESOLVE with 10 load and capacity zones - with those overlapping with Virginia (DOM, AEP, AP, East) broken into VA vs non-VA subzones**
  - This topology allows us to model VA specific assumptions and constraints (e.g. WCC's load forecast and VCEA policies) while capturing the broader market dynamics within PJM
  - Transmission constraints between these zones are derived from information provided by Energy Exemplar
  - Transmission upgrades between DOM and its neighboring zones (AEP, AP, and NW) are modeled as an option to allow more detailed examination of transmission infrastructure upgrade needs to support data center load growth in Northern Virginia
+ **The modeling horizon covers 2025-2050 for this study**



Key Modeling Assumptions

+ **Load Forecasts** derived from information provided by WCC and published by PJM (2024)
+ **Existing Resources** grouped by zones, technology, fuel, and quality tiers (e.g. high/mid/low heat rates for thermal units)
  - Planned resources expected through 2027/2028 included as expected additions
+ **Candidate Renewable Resource Potential** drawn from the National Renewable Energy Laboratory's (NREL) ReEDS supply curve
  - Potentials, capacity factors, and interconnection costs for solar PV, onshore wind, and offshore wind candidate resources
+ **Candidate Resource Costs** developed leveraging NREL's 2024 Annual Technology Baseline (ATB) forecast and standard E3 financing assumptions
  - Includes escalating local network upgrade costs for renewables which are developed based on transmission projects recently approved by PJM in the DOM zone, in addition to the specific resource interconnection costs from NREL ReEDS
+ **Policy Assumptions**
  - EPA regulations, post 2030, constrain new gas builds to a 40% annual capacity factor and require existing coal units to co-fire with natural gas
  - RGGI modeled for participating states (NJ, MD, DE) in the East transmission zone, with price forecast developed by E3
  - States' RPS policy and clean energy carveouts modeled
  - VCEA requirements considered in the VCEA compliance scenarios

Transmission Upgrades

Transmission upgrades can be broadly categorized into the following groups:

+ **Intra-zonal transmission upgrades**

Captured in model at high level; see next slide for details

- **Resource interconnection |** Spur line constructed to connect individual projects to nearest substation
- **Resource-driven local network upgrade |** Upgrade needed for medium to high voltage local transmission system to allow delivery of new resources to loads

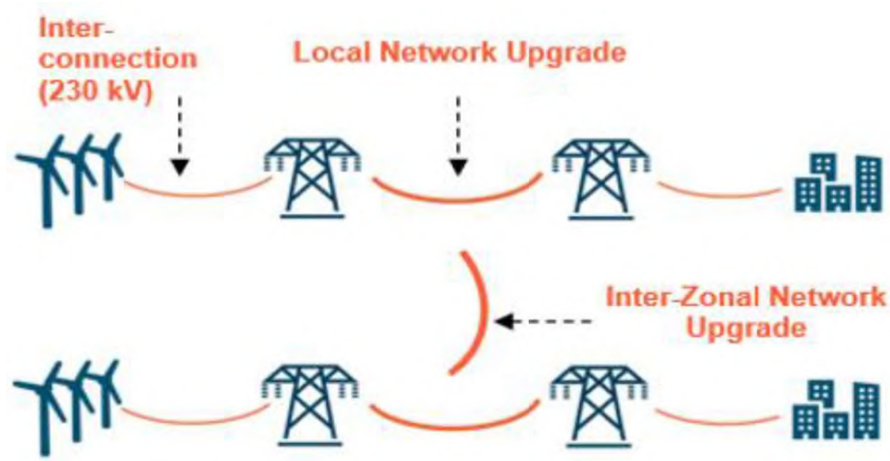
Not captured in model

- **Load growth-driven local network upgrade |** Upgrade needed for local transmission system to address reliability/thermal dynamic issues associated with interconnection of new loads

+ **Inter-zonal transmission upgrade**

Captured in model at high level; see next slide for details

- Upgrade needed to increase transfer capability between regions in the bulk power system



Transmission Assumptions in RESOLVE

Existing transmission constraints:

- **Inter-zonal constraints |** Our capacity expansion model (RESOLVE) captures existing transmission constraints between PJM's load and capacity zones using a "pipe-and-bubble" framework, leveraging the PJM database from Energy Exemplar

Potential transmission expansion and costs:

- **Interconnection |** Our analysis considers and reports potential interconnection costs associated with the additions of new renewable capacity
- **Local network upgrades |** Our analysis considers and reports local network upgrade costs associated with the additions of new renewable capacity; a transmission cost curve was developed for new renewables in each zone (higher transmission upgrade costs as a function of increased renewable deployment), which was considered as part of the total resource cost for renewables in capacity expansion
- **Inter-zonal upgrades |** Our analysis also includes an option for the model to select inter-zonal transmission upgrades between DOM and neighboring transmission zones (AEP/AP/NW) with escalating costs
  - Our model topology was built on existing system constraints since the detailed transfer limit impacts of the recently approved PJM RTEP Window 3 projects are still being studied; as a result, the reported incremental investments can be considered a mix of both approved (Window 3) and new projects

Notes and caveats:

- We did not model load growth-driven intra-zonal transmission upgrades, which would require more detailed transmission system modeling and information regarding the placement of new data center loads
  - Many of the RTEP window 3 projects were approved to address reliability challenges to connect new large loads within the DOM zone; as a result, our model results should not be compared on an apples-to-apples basis with the RTEP study
- We assumed new capacity resources (e.g. gas, battery, SMR) can be located near loads and thus do not require significant amount of transmission upgrades. Should there be potential constraints on where those resources can be added, additional transmission upgrade costs might be incurred with the addition of those resources
- The transmission upgrade costs reported from our modeling reflects annualized transmission upgrade costs, which cannot be directly compared to the upgrade costs reported in PJM's RTEP study, which reflects the total upfront investments needed

Regional and Sub-Regional Resource Build Limits

+ **Build limits are implemented by technology, location, and future model year**
  - *Resource potentials* - Based on NREL ReEDs and with further adjustments, each resource type has a **total potential build amount** available for each of several subzones (also known as NREL's "p-zones"). These potentials inform the **quality and location** for an exhaustive list of candidate resources.
  - *Interconnection limits* – Based on geographical location relative to the grid and **how much new transmission would need to be built** to link resources to the existing grid. These limits also dictates the **pace of resource potential availability** over the modeling period, assuming further out resources are not available right away in 2030 and 2035.
  - *Build rate limits* – Based on historical build rates and the interconnection queue by zone and by technology, the model constrains **how much can reasonably be built by 2030** (more stringent) and by 2035 (less stringent) in each major zone. These **build rates apply to renewables as well as thermal resources and storage**.
+ **The amount of capacity that can be added in a given area also incurs higher transmission network upgrade costs**
  - *Deliverability limits* – Based on estimated **grid upgrade requirements** in each subzone, new renewable resources need to be accompanied by substation and transmission line upgrades which have their own **implied costs and upgrade rate limits**. Solar and wind resources in the same subzones share the same deliverability limits and required upgrade costs.

Scenario Matrix

Assumptions/Scenarios	No DC Growth No VCEA	No DC Growth With VCEA	Moderate/Unconstrained DC Growth No VCEA	Moderate/Unconstrained DC Growth With VCEA
Load	No Data Center load growth in VA post 2023	No Data Center load growth in VA post 2023	Moderate or Unconstrained Data Center load growth	Moderate or Unconstrained Data Center load growth
VCEA Compliance	No	Yes (IOU or Statewide)	No	Yes (IOU or Statewide)
Existing Thermal	Economic Retirement	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs	Economic Retirement	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs
Candidate Renewables, Storage, Gas	Build rate limits through 2035	Build rate limits through 2035	Build rate limits through 2035	Build rate limits through 2035
Hydrogen	Not available	Available [1]	Not Available	Available [1]
SMR (nuclear)	Not available	Available 2035+ with build limits	Available 2035+ with build limits	Available 2035+ with build limits
Capacity Purchases and Transmission Upgrades	Capacity purchase allowed up to 3 GW; No transmission upgrade allowed	Capacity purchase allowed up to 3 GW; No transmission upgrade allowed	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits

[1] The consumption of hydrogen for power generation would also require additional fuel delivery and storage infrastructure; the costs of such infrastructure is captured at a high level on a $/MMBtu basis. However, these costs assume that Virginia is able to access a robust regional hydrogen economy that is already in place in the future, and costs would be higher if Virginia is building new / first-of-a-kind infrastructure.

Additional Sensitivities on Feasibility

Assumptions/Scenarios	Unconstrained DC Growth With VCEA (S3C)	Unconstrained In-State Renewables (S3C: HighRen)	Regional Coordination (S3C: RegCoord)	Nuclear Renaissance (S3C: NucRen)
Load	Unconstrained VA DC load growth	Same as S3C	Same as S3C	Same as S3C
VCEA Compliance	Yes	Same as S3C	Same as S3C	Same as S3C
Existing Thermal	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs	Same as S3C	Same as S3C	Same as S3C
Candidate Renewables, Storage, Gas	Build rate limits through 2035	Higher onshore wind availability and accelerated offshore wind allowed	Same as S3C	Same as S3C
Hydrogen	Available	Same as S3C	Same as S3C	Same as S3C
SMR	Available 2035+ with build limits	More stringent SMR build limits and higher costs	More stringent SMR build limits and higher costs	No SMR build limits
Capacity Purchases and Transmission Upgrades	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits	Same as S3C	Relaxed transmission build limits	Same as S3C

Additional Sensitivities on Load Flexibility

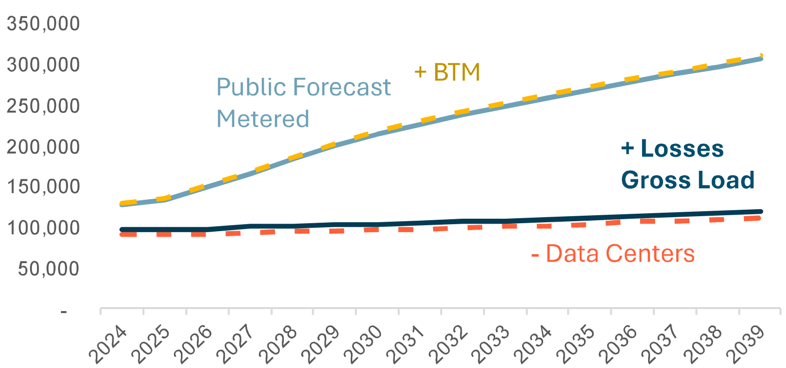
Assumptions/Scenarios	Unconstrained DC Growth With VCEA (S3C)	2-hr Flexible Load	4-hr Flexible Load	8-hr Flexible Load	120-hr Flexible Load
Load	Unconstrained VA DC load growth	10% DC load modeled as 2-hr battery in 2050	10% DC load modeled as 4-hr battery in 2050	10% DC load modeled as 8-hr battery in 2050	10% DC load in 2050 modeled as 120-hr demand response or on-site generation, with 5 24-hr calls per year
VCEA Compliance	Yes	Same as S3C	Same as S3C	Same as S3C	Same as S3C
Existing Thermal	Coal/oil/biomass retire in 2045; Gas optional to convert to hydrogen by 2045 with incremental costs	Same as S3C	Same as S3C	Same as S3C	Same as S3C
Candidate Renewables, Storage, Gas	Build rate limits through 2035	Same as S3C	Same as S3C	Same as S3C	Same as S3C
Hydrogen	Available	Same as S3C	Same as S3C	Same as S3C	Same as S3C
SMR	Available 2035+ with build limits	Same as S3C	Same as S3C	Same as S3C	Same as S3C
Capacity Purchases and Transmission Upgrades	Capacity purchase allowed with transmission upgrades required beyond 3 GW; Transmission upgrades allowed post 2035+ with limits	Same as S3C	Same as S3C	Same as S3C	Same as S3C

Appendix B: Load Benchmarking

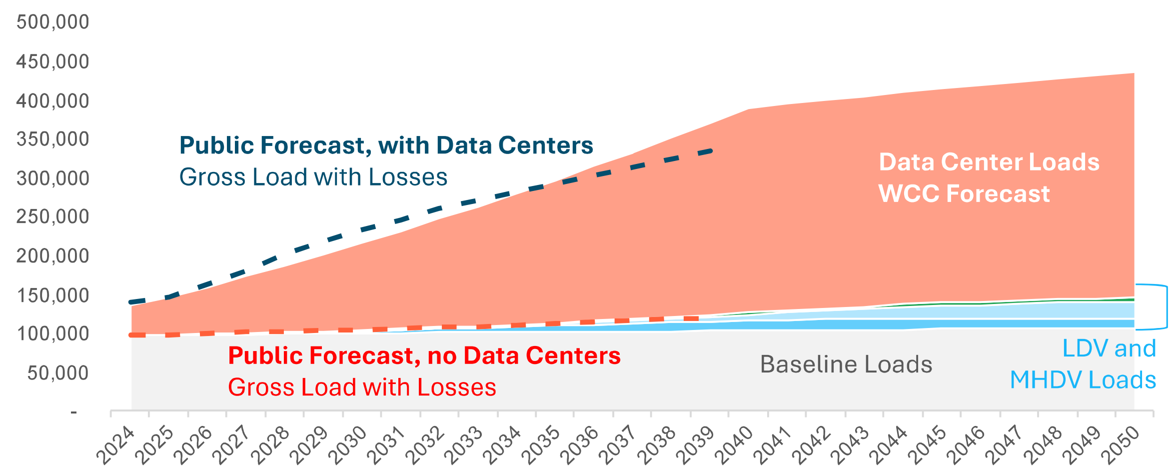
Load Projections Compared to 2024 PJM Forecast

- **E3 supplemented WCC's forecast with PJM's 2024 load forecast in our grid impact modeling**
  - Load growth outside of Virginia, including data center loads, were derived from the public PJM forecast and kept constant across different VA data center load growth scenarios
  - E3 also extrapolated the load forecasts from WCC and PJM to 2050
    - Data center load growth is assumed to slow down to 1%/year between 2040 and 2050
    - Baseline and vehicle electrification loads each are assumed to grow at a constant rate based on the last 5 years of the forecast
- **As a benchmark, energy forecasts for the DOM zone using a combination of WCC forecast (for VA portion) and the PJM public forecast (for non-VA portion) are generally aligned through the end of the PJM forecast period (2039)**
  - E3 adjusted the PJM forecast by adding back BTM generation so that gross load can be compared

PJM 2024 Forecast - Dominion (DOM Zone)
Annual Load, GWh

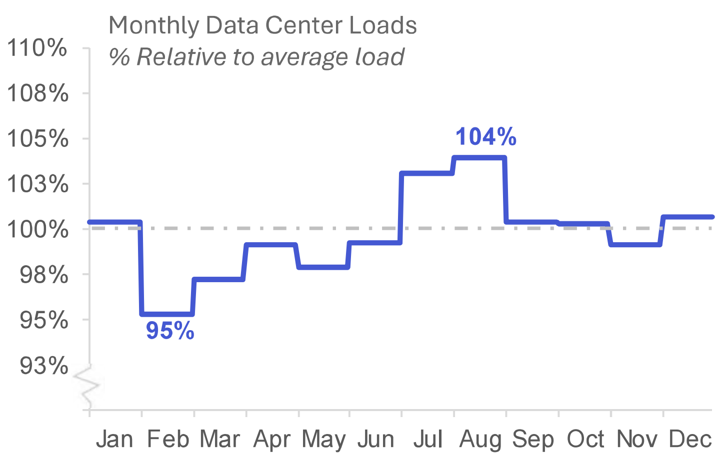


Adjusted with WCC Forecast - Dominion (DOM Zone)
Annual Load, GWh

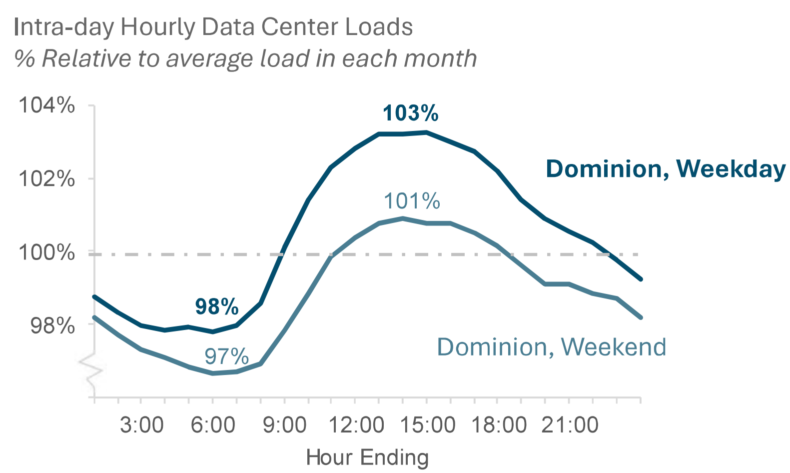


Hourly Data Center Load Profiles

- **The data center load projections provided by WCC are in annual and monthly energy**
- **Seasonal variations of data center loads are driven by cooling needs amongst other factors**
  - Loads are the highest in summer months, with August having average loads 4% higher than the annual average
  - With lower cooling needs and ideal operating temperatures, the spring months see the lowest average loads

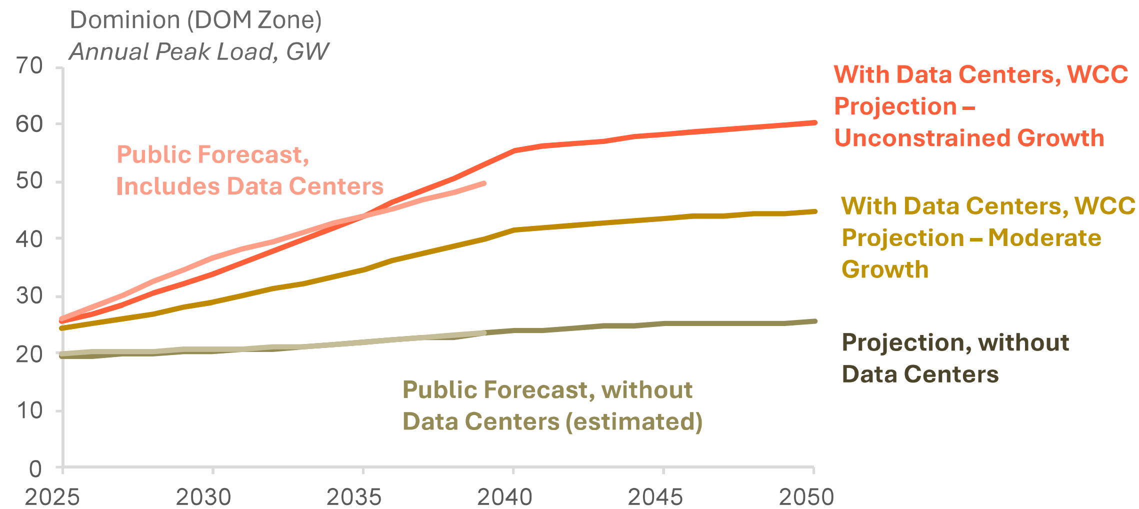


- **Hourly data center load shapes were developed by E3**
  - **Monthly average loads** from WCC forecast, with +-5% variation throughout the year
  - **Intra-day hourly loads** from PJM's public report of example July peak day July hourly load for Dominion and NOVEC data centers, with +-2.5% variation hour-by-hour
  - **Final load shapes** from applying hourly variations to each month's load, with maximum annual variation of +-6.5%



Peak Projections Compared to PJM Forecast

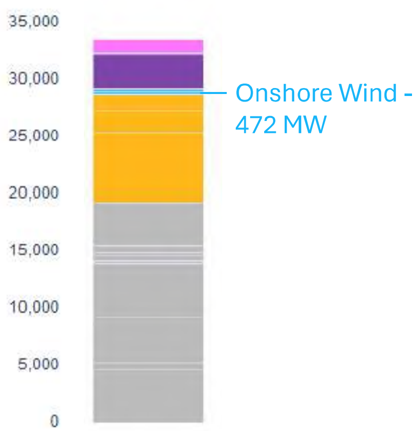
- **Projected median peak for the DOM zone using E3 assumed load profiles generally aligns with PJM's 2024 load forecast**
  - Small differences can result from variations in the weather dependent hourly profiles for the baseline and transport electrification loads
  - The peak impact of data centers in the PJM 2024 forecast is estimated from the July peak loads reported in the forecasts' supplement
- **While data center loads in Dominion came from WCC, other projected data center loads in AEP, APS, and East outside Virginia were kept from PJM's 2024 forecast**



Appendix C: Reliability Modeling

Dominion Wind ELCCs

Incremental additions relative to existing resource portfolio

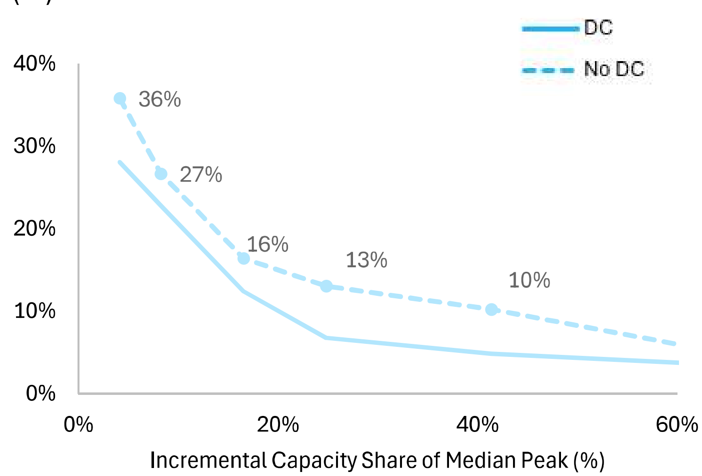


Modeled 2050 DOM Portfolio in RECAP

Wind ELCCs are lower when data center loads are presented

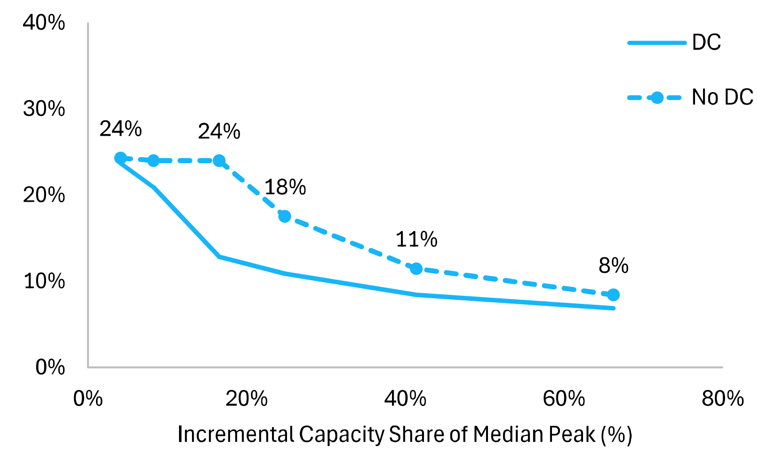
which shift system loss of load risks to summer when wind generation is lower

Offshore Wind Incremental ELCC (%)



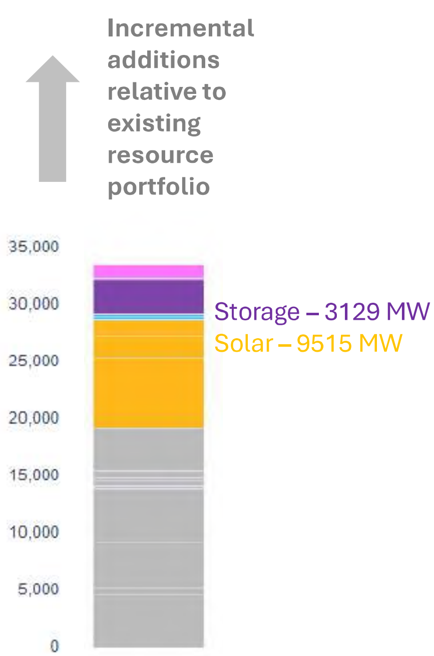
Onshore Wind ELCC is generally lower than Offshore Wind given the lower capacity factor

Onshore Wind Incremental ELCC (%)



Med peak w DC: 68 GW
Med peak w/o DC: 31 GW

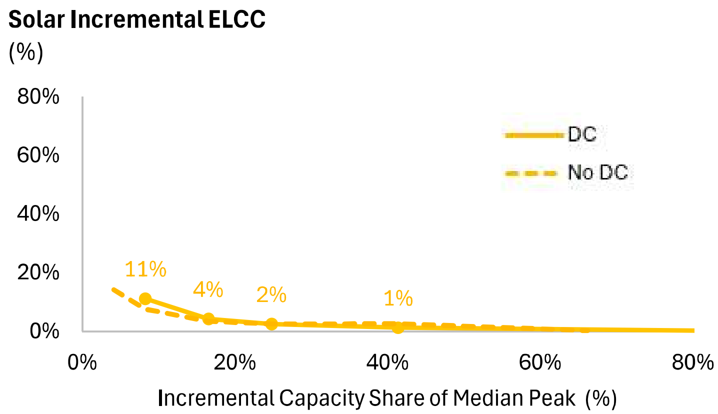
Dominion Solar and Storage ELCCs



Modeled 2050 DOM Portfolio in RECAP

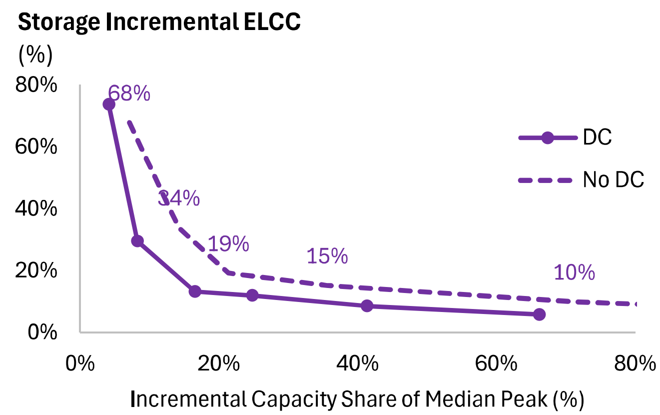
Solar ELCCs are slightly higher when data center loads are presented

when most of the loss-of-load expectations are in summer when solar generation peaks



Storage ELCCs start higher, but saturate quickly when data center loads are presented

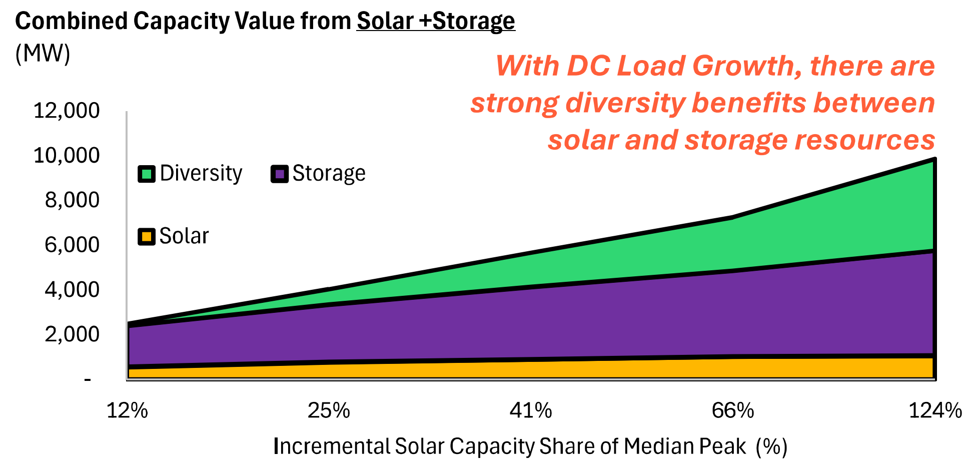
given the strong saturation effect in summer early evenings when storage are quickly needed to discharge for a long time-frame

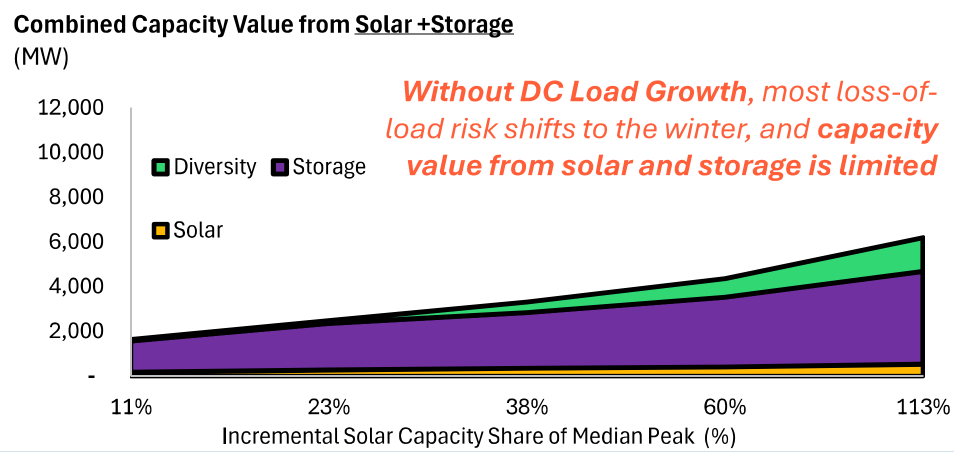


Med peak w DC: 68 GW
Med peak w/o DC: 31 GW

Complementary Reliability Impacts between Solar and Storage

- **Adding solar and storage can quickly exhibit saturation effects, while combinations of the two resources exhibit interactive benefits**
  - Positive interactive effects between solar and storage are referred to as "diversity benefits"
- **This comes from the complimentary nature of the two resources**
  - Abundant solar makes the net load evening peaks sharper, which increases value of limited duration energy storage resources
  - This is more prominent when data center load growth is presented, which creates concentrated reliability challenges in summer afternoons

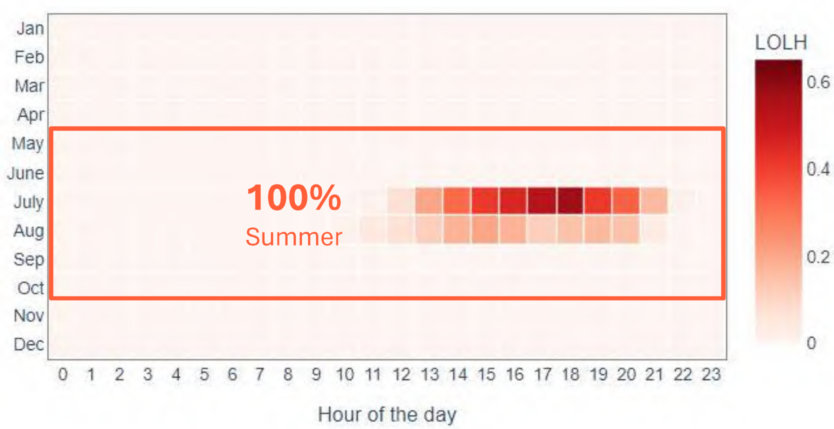




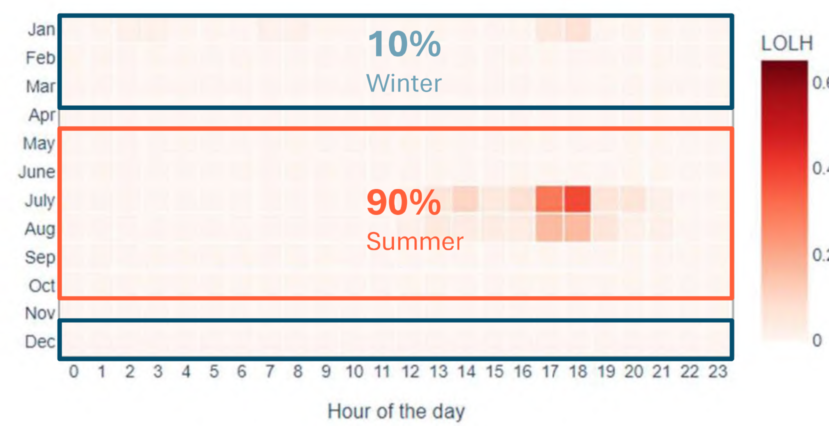
PJM System Reliability Risks

- In 2025, all loss of load risks are concentrated in summer in PJM
- While winter becomes more challenging in 2050, the majority of system needs are still in summer afternoon through evenings
- Higher data center load growth in Virginia is expected to drive more concentration of loss of load risks in summer and will have limited impacts on system reliability needs or resource accreditation across PJM

2025 – Existing PJM System

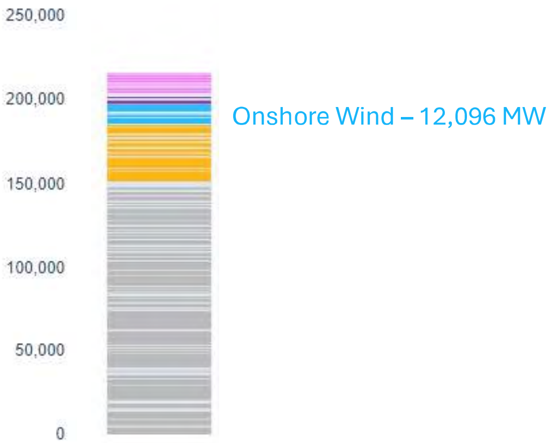


2050 – Existing PJM System, No Data Center Growth



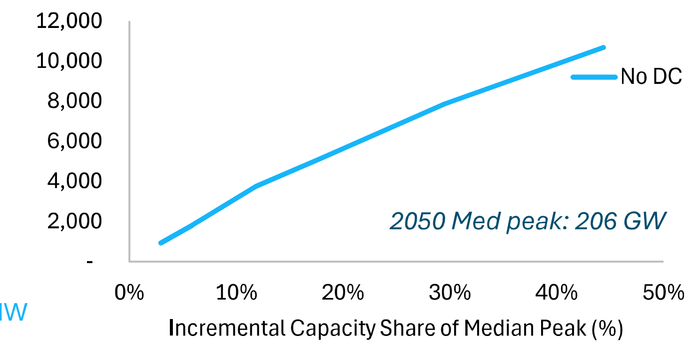
PJM Wind ELCCS

Incremental additions relative to existing resource portfolio

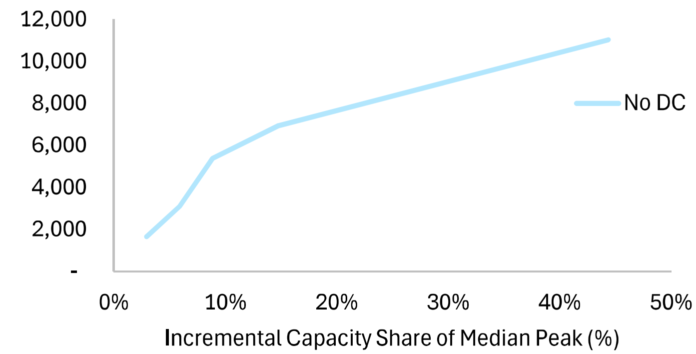


Modeled 2050 PJM Portfolio in RECAP

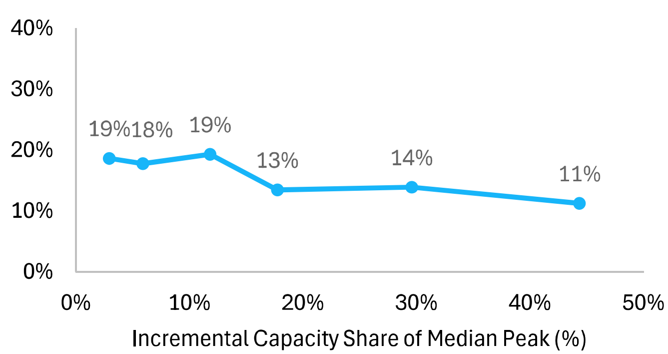
Onshore Wind Capacity Value (MW)



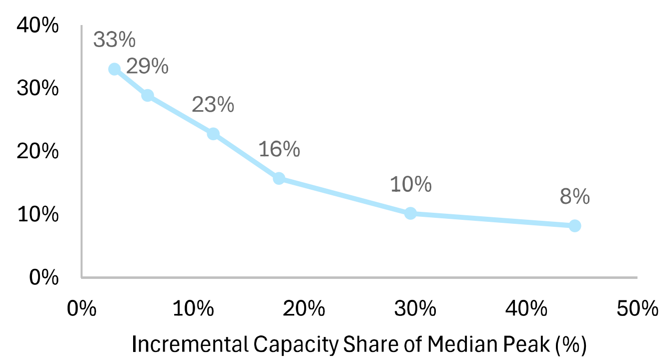
Offshore Wind Capacity Value (MW)



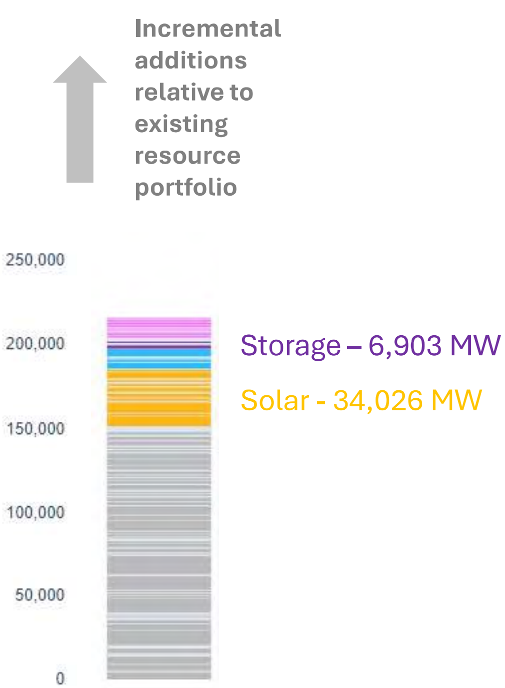
Onshore Wind Incremental ELCC (%)



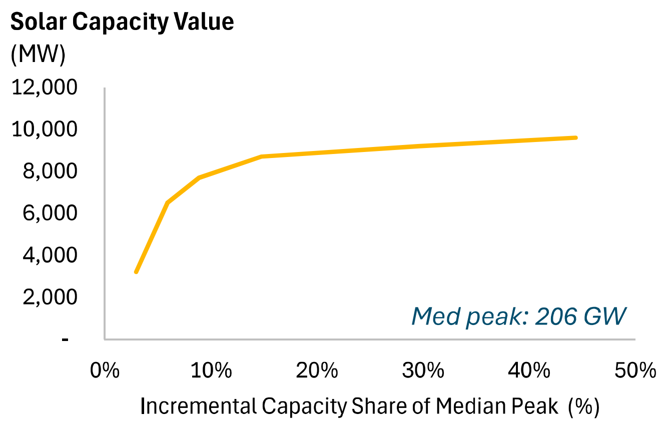
Offshore Wind Incremental ELCC (%)

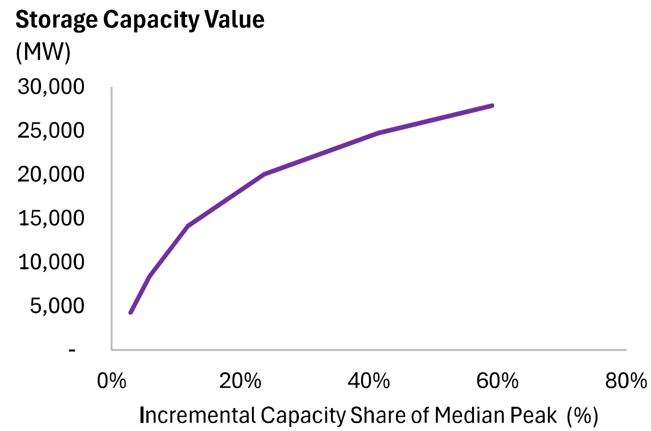


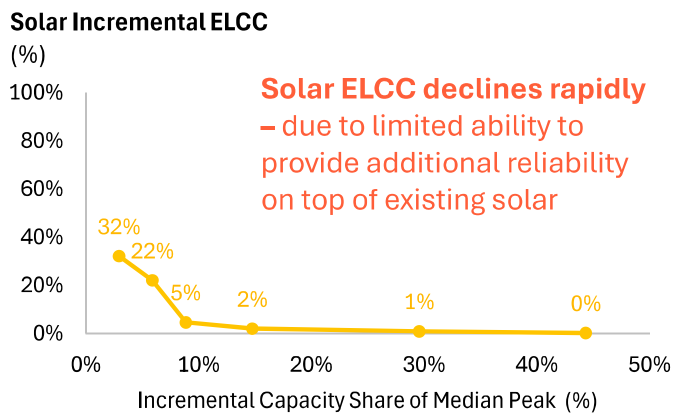
PJM Solar and Storage ELCCs

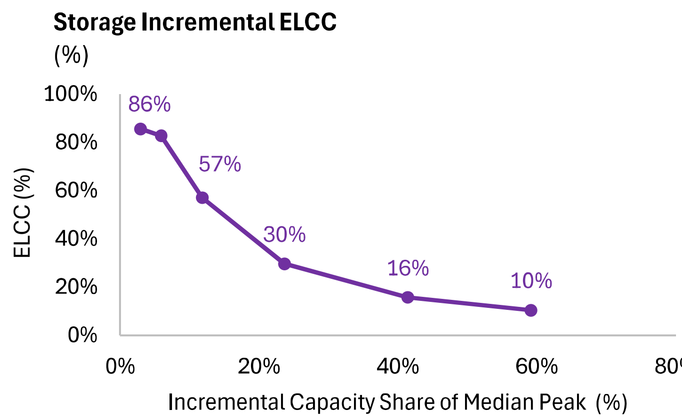


Modeled 2050 PJM Portfolio in RECAP









Appendix D:
Value of Flexibility

With Unconstrained Data Center Growth and Statewide VCEA Achievement (S3C)

Energy+Environmental Economics

Context of the Flexibility Sensitivity Study

- **Most of the data center facilities currently located in Virginia are cloud computing facilities, which have low latency (and thus high power intensity) requirements and are generally not flexible**
  - DC load shapes are roughly flat throughout the year, with small seasonal variations due to higher cooling requirements in the summer
- **Data center facilities providing AI training services may have higher flexibility, but are generally less expected to be located in Virginia**
- **Data center customers are generally less incentivized and not required by policy to explore demand response and load flexibility options**
- **E3 performed a few exploratory sensitivity analysis to examine the potential value of load flexibility in Virginia in a future with high data center load growth and stringent requirements of the VCEA to inform potential policy discussions**
  - Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion
  - E3 examined the capacity value of short-duration on-site backup generators and technologies allowing longer-duration load shedding/shifting through RECAP modeling as an approximation of the capacity offset these technologies could provide

Flexibility in Data Center Load Offsets System Capacity Need

- **Assuming 10% of the total DC load in 2050 (~3GW) is coupled with short-duration onsite storage, which enables load shifting during emergency events, 266 to 606 MW of system capacity need can be offset when these resources are added on top of a reliable system**
  - This approach shows the value in a scenario in which this flexibility is called upon only in emergencies (e.g. a diesel generator violating its air permit, or a data center shedding very valuable load)
- **2,223 to 2,410 MW of system capacity need can be offset when these resources are added upfront before other capacity resources are added to the system**
  - This approach represents a scenario in which this flexibility is made more readily available when the new data center load is added to the system, e.g. if data centers are required have on-site storage that they can dispatch, or if there are AI loads that are not critical, etc.
  - The value is higher when the load flexibility can be called more often or on a regular basis, which offsets some of the need of adding new capacity at utility level
- **The capacity value is higher when longer-duration load reduction can be achieved in the last-in case, potentially enabled through onsite backup gas generator or other emerging technologies**
  - The 120-hr backup generator was modeled as a demand response resource with up to 5 call times per year; This specific assumption and model setup limits the capacity value under the first-in case

Last-in ELCC

Proxy Data Center Resource	Capacity Value (MW)	ELCC (%)
2-hour storage 3 GW	266	9%
4-hour storage 3 GW	331	11%
8-hour storage 3 GW	606	20%
120-hour backup generator 3 GW	1,292	43%

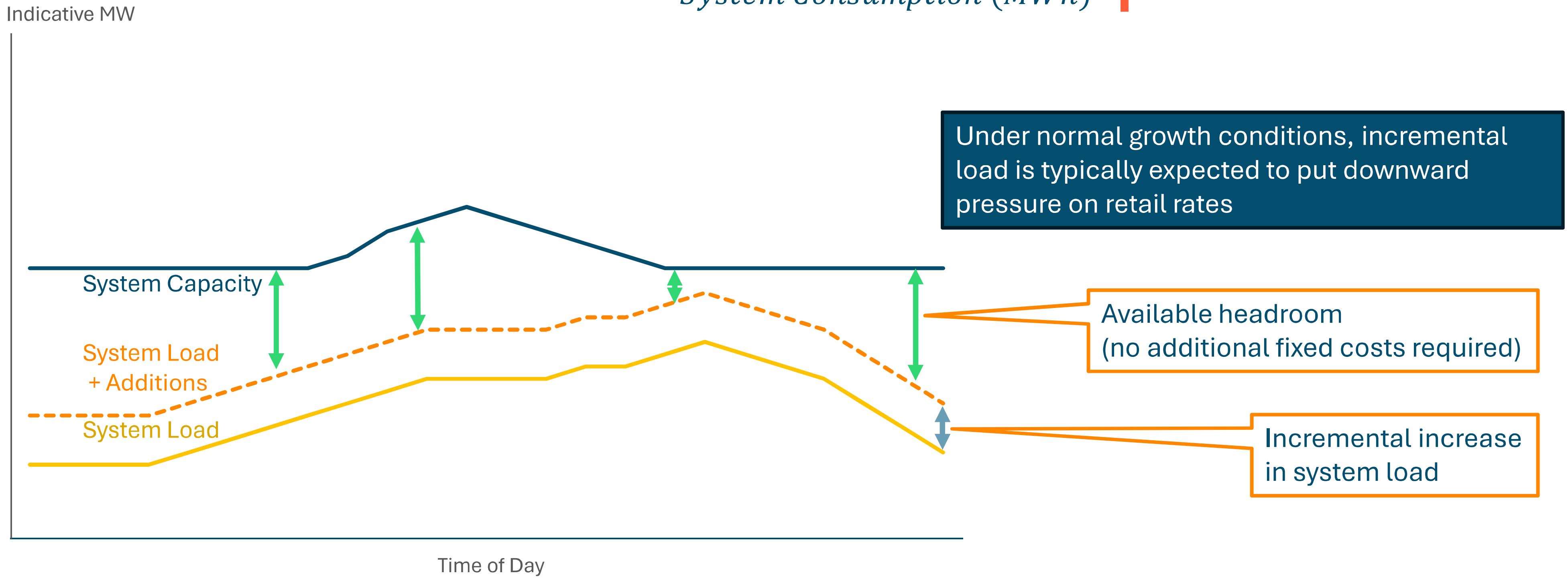
First-in ELCC

Proxy Data Center Resource	Capacity Value (MW)	ELCC (%)
2-hour storage 3 GW	2,223	74%
4-hour storage 3 GW	2,375	79%
8-hour storage 3 GW	2,410	80%
120-hour backup generator 3 GW	1,963	65%

Appendix E:
Rate Dynamics

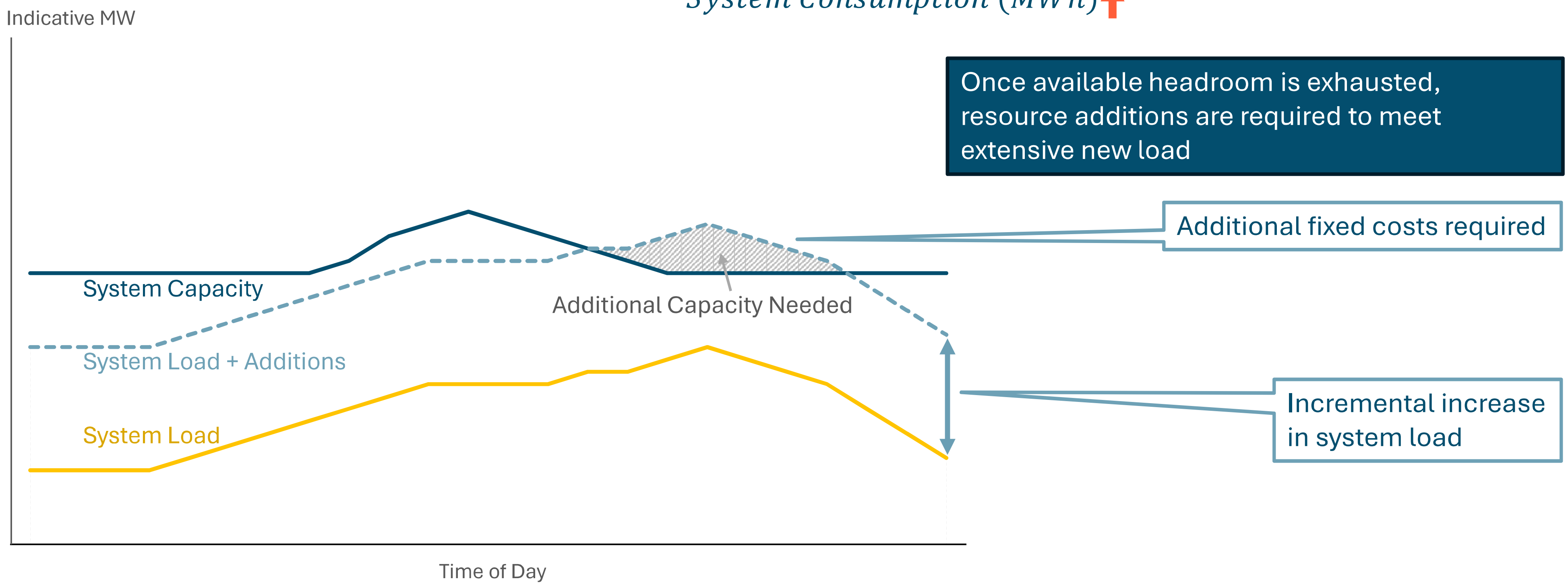
Modest Incremental Load Growth

$$\downarrow Retail\ Rates \propto \frac{(Fixed\ Costs + Variable\ Costs)\uparrow}{System\ Consumption\ (MWh)\uparrow}$$

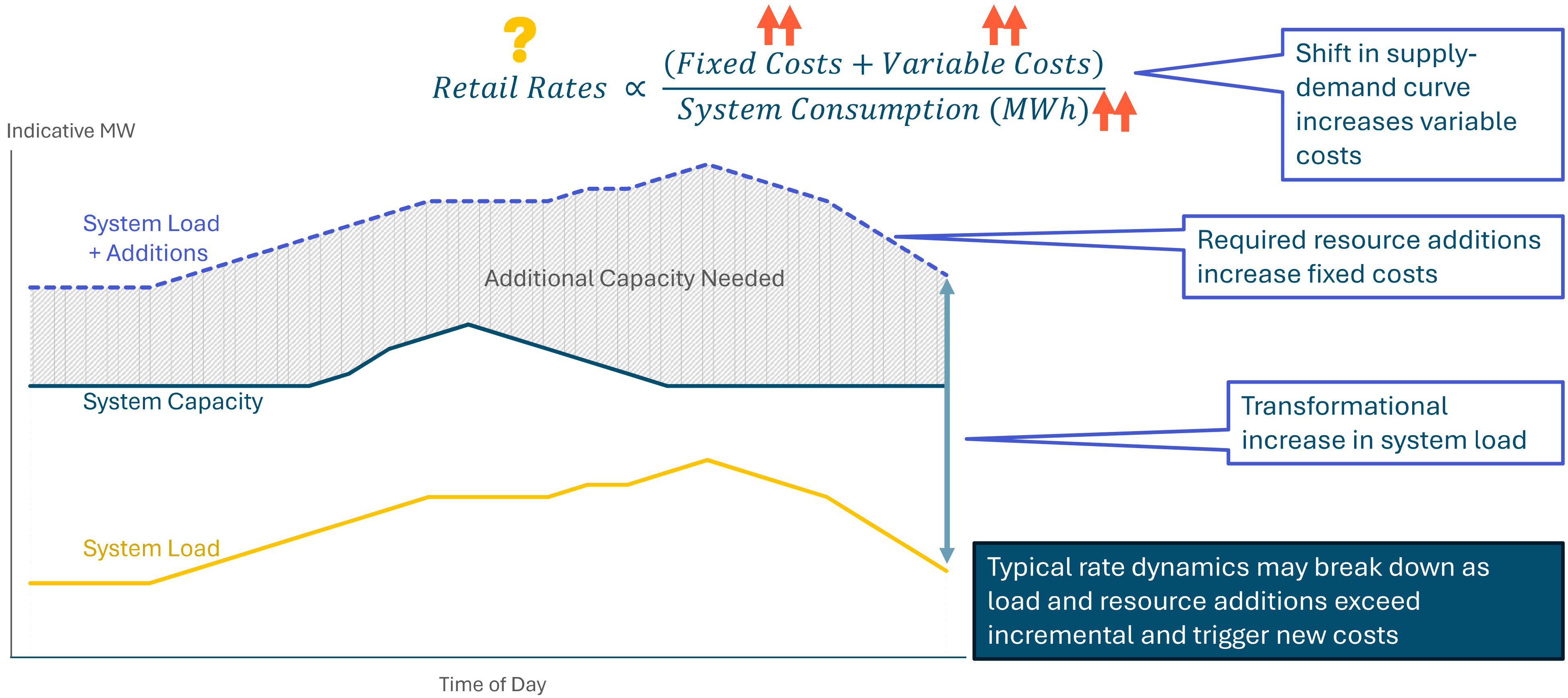


Moderate Incremental Load Growth

$$\mathit{Retail\ Rates} \propto \frac{(\mathit{Fixed\ Costs} + \mathit{Variable\ Costs})}{\mathit{System\ Consumption}\ (\mathit{MWh})}$$



Transformational Load Growth



Typical rate dynamics may break down as load and resource additions exceed incremental and trigger new costs

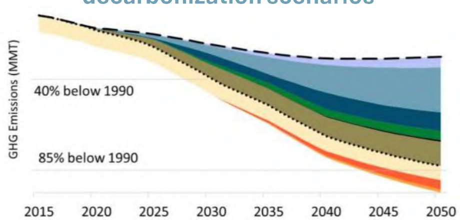
Appendix F: Overview of E3 Modeling Capabilities

Energy+Environmental Economics

E3's comprehensive modeling toolkit positions E3 well to study future energy system dynamics

PATHWAYS

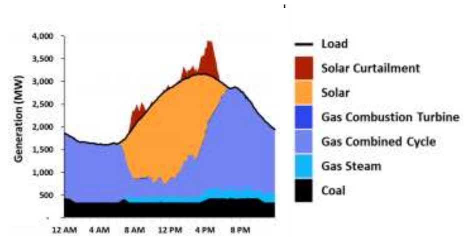
Economy-wide accounting of energy supplies and demands under deep decarbonization scenarios



Production Simulation

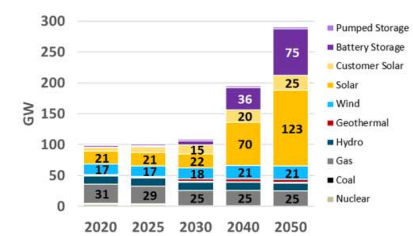
(AuroraXMP and PLEXOS)

Detailed operational simulations of system dispatch and flexibility needs



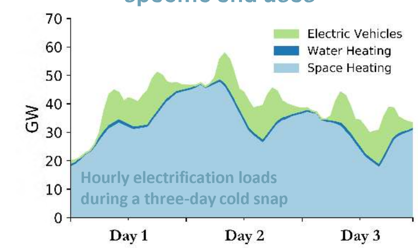
RESOLVE

Optimal capacity expansion model for electric systems



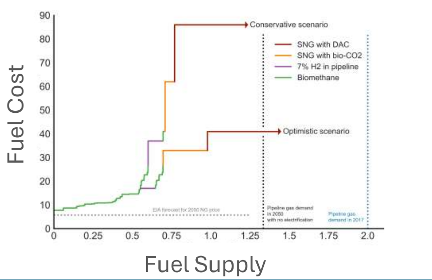
RESHAPE & EVGrid

Hourly simulations of electric loads for specific end uses



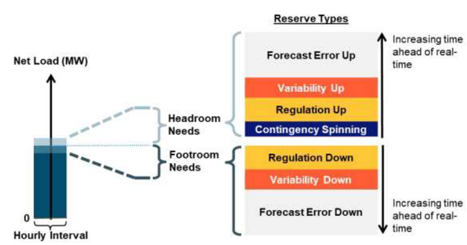
Low-Carbon Fuels and Future of Gas

Role of fuels in deep decarbonization



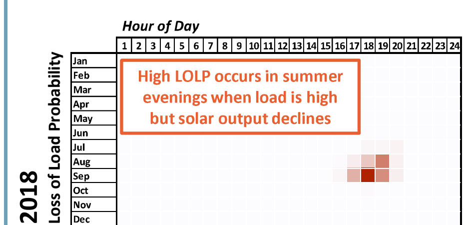
RESERVE

Dynamic operating reserves for renewable integration



RECAP

Loss of load probability simulation to measure resource adequacy



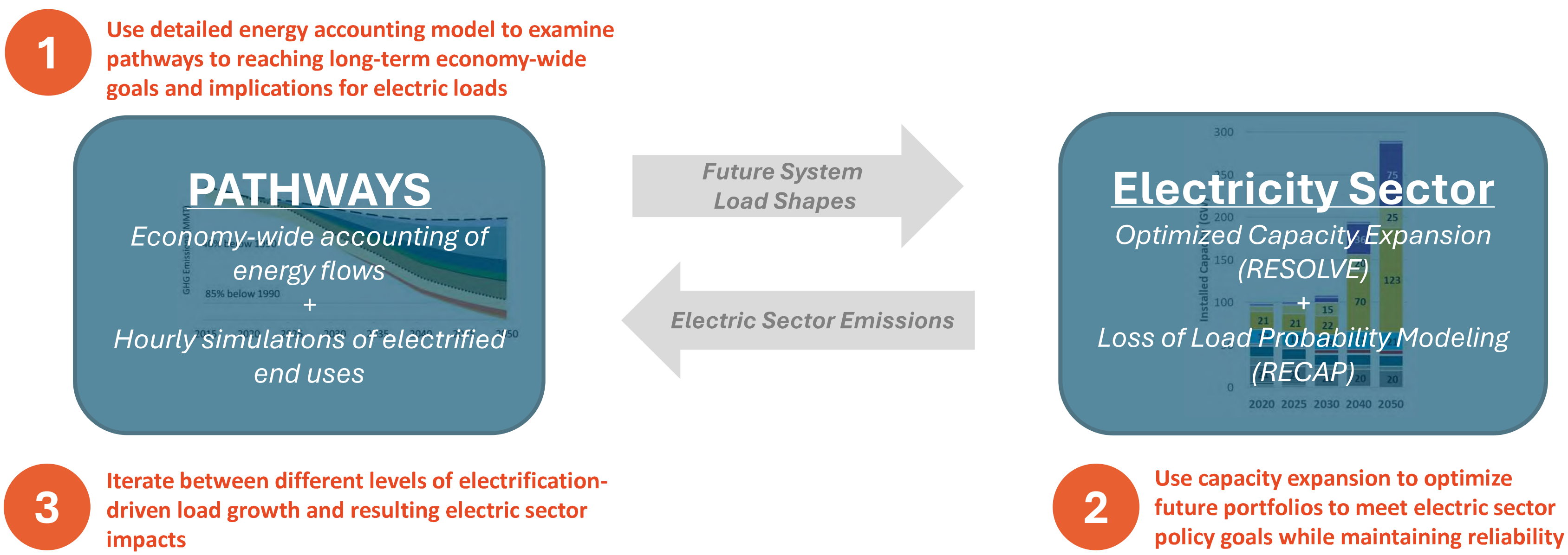
RESTORE & IDSM

DER Toolkit for optimizing DER value stacking opportunities and adoption

Economy-wide energy systems — Bulk grid power systems — Grid edge & behind-the-meter

E3's Best-in-Class Modeling for Grid Decarbonization

- E3's integrated analytical framework combines a detailed accounting model of energy supplies and demands across the entire economy with an optimized capacity expansion model in the electric sector
- Detailed modeling of the rest of the economy provides a clear picture of how both the magnitude and timing of electric sector loads will need to change, as electrification plays a key role in the decarbonization of buildings, transportation, and industry



Recent Applications of RECAP

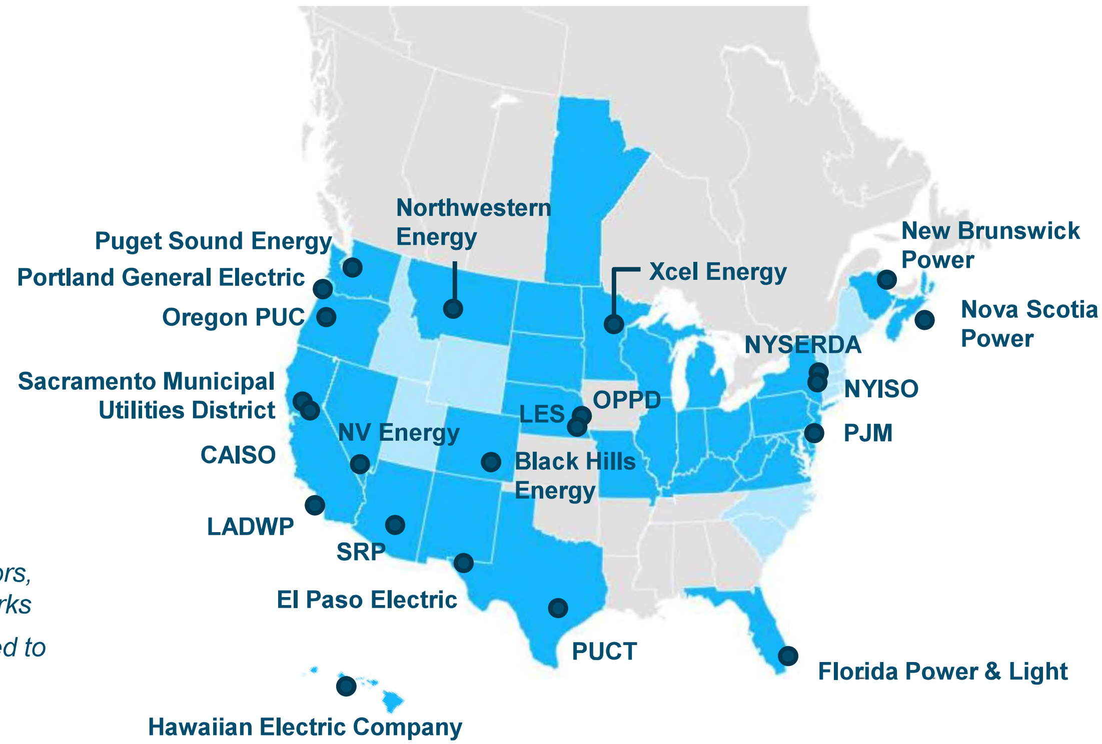
E3 has developed RECAP, a proprietary model for performing loss of load analysis

- Simulation model for assessing resource availability over **hundreds of simulation years**
- **Time-sequential dispatch** for capturing energy-limited resource dynamics for hydro, energy storage, and demand response

States where E3 has provided direct support to utilities, market operators, and/or state agencies to perform RA modeling or develop RA frameworks

Areas where E3 has worked with other clients to examine issues related to resource adequacy

E3 has worked directly with utilities across North America to study resource adequacy needs



E3 Model Ecosystem for Market Price Forecasts: Built on Decades of Experience and 360° Analysis

E3 Model Toolkit

Input Models

E3 PATHWAYS
Least-cost decarbonization pathways across sectors to meet GHG targets

E3 RESHAPE
Load simulation for building electrification & EVs

E3 Pro Forma Model
Levelized costs of new resources including financing and tax incentives

E3 RECAP
Stochastic reliability modeling for ELCCs of renewables and storage

Output Models

E3 RESTORE
Optimized battery operations and revenues

E3 Scarcity + RT Price Model
Forecasts scarcity and real-time energy prices with regression analysis

E3 Nodal Price Model
Node-zone basis forecast for nodal prices

E3 Ancillary Services Model
Forecasts AS prices with regression analysis and market saturation

E3 Capacity Market Models
Capacity price formation by market, aligned with unique market dynamics

E3 REC Market Models
Renewable Energy Credit prices aligned with unique market dynamics

Market Price Forecasting Approach

Key Scenario Variables

1 **Load Forecasts**
Regional load growth, energy efficiency, building electrification, and EVs

2 **Policies**
RPS, CES, GHG, other mandates

3 **Regional Coordination**
Transmission, Trading, and policy alignment

4 **Costs:**
- New resource costs
- Gas prices
- Carbon prices

PLEXOS Model Outputs

5 **Long-Term Capacity Expansion (Annual)**

New Resource Additions
- Economics
- Policies and mandates (RPS, CES, GHGs)
- System reliability needs
- Retirements

6 **Production Cost Simulation (Hourly)**

Energy Market Forecasts
- Hourly day-ahead energy prices by zone
- Dispatch, renewable curtailment, and transmission flows

E3 Forecasts

Market Product	Geographic Granularity	Temporal Granularity
Energy (Day-Ahead and Real-Time)	Zonal	Hourly
Capacity (low, medium, high forecasts)	System / Local	Annual
Ancillary Services (Reg, Spin, Non-Spin)	ISO	Hourly
ELCC Curves	Regional	Annual
RECs	State / ISO	Annual
System Operations	System / Local	Hourly / Monthly

Fundamentals-based market modeling built on day-ahead energy prices