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October 13, 2025

Via eDocket and electronic submission

Sasha Bergman, Executive Secretary
Minnesota Public Utilities Commission
121 East Seventh Place, Suite 350
Saint Paul, MN 55101

RE: ***In the Matter of Northern States Power Co.'s, d/b/a Xcel Energy's, Petition for Approval of Large General Time of Day Service and Large Peak Controlled Time of Day Service Tariffs***
MPUC Docket No. E-002/M-25-289

Dear Ms. Bergman,

Please find attached the *Petition to Intervene and Initial Comments of Data Center Coalition* in Docket No. E-002/M-25-289.

Sincerely,

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STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
John Tuma	Commissioner
Hwikwon Ham	Commissioner
Audrey Partridge	Commissioner

In the Matter of Northern States Power Co.'s, d/b/a Xcel Energy's, Petition for Approval of Large General Time of Day Service and Large Peak Controlled Time of Day Service Tariffs

PETITION TO INTERVENE AND INITIAL COMMENTS OF DATA CENTER COALITION

October 13, 2025

Docket No. E002/M-25-289

Pursuant to the Notice of Comment Period issued by the Minnesota Public Utilities Commission (Commission) on July 29, 2025, and the Notice of Extended Comment Period issued on September 19, 2025, the Data Center Coalition (DCC) respectfully files its Initial Comments and Petition to Intervene in the above-captioned proceeding.

ABOUT DATA CENTER COALITION

DCC is the national membership association[1] for the data center industry, representing leading data center owners and operators who maintain data center infrastructure across the country and globe, as well as companies that lease large amounts of data center capacity. DCC empowers and champions the data center community through public policy advocacy, thought leadership, stakeholder outreach, and community engagement. Our membership includes both enterprise companies building data centers to support their own operations, as well as companies

[1] The Data Center Coalition is a membership organization of leading data center owners and operators. Public testimony and written comments submitted by DCC do not necessarily reflect the views of each individual DCC member. A list of current DCC Members is accessible at https://www.datacentercoalition.org/members.

building or leasing space in data centers commonly known as "multitenant" or "build-to-suit" facilities. As the voice of the data center industry, DCC also advocates for a highly skilled and diverse technology workforce, greater access to clean energy, and a competitive business environment to support the growth and success of this essential business sector. DCC members are actively investing in growth to continue to build out Minnesota's digital infrastructure.

PETITION TO INTERVENE

Pursuant to Minn. R. 7829.0800, subp. 1, DCC respectfully requests to intervene as a party to this proceeding. Pursuant to Minn. R. 7829.0800, subp. 2, the grounds for DCC's intervention are that Xcel Energy's (Xcel) proposals in this proceeding will bind and affect DCC's members with respect to interests unique to DCC's members and that these interests are not represented by any other parties that may participate in this case.

Specifically, as stated above, DCC's membership includes developers, owners, and operators of data centers, including data centers that are operational, under development, and being planned in Xcel's Minnesota service territory. Many of DCC's members may be required to take service on Xcel's proposed Large General Time of Day Service tariff if the proposed tariff is approved or approved with modifications. If approved, many of DCC's members will also have the option to take service on Xcel's proposed Large Peak Controlled Time of Day Service tariff or on Xcel's proposed revised Tier 1 Energy Controlled Service rider tariff. As a result, DCC's members will be bound by and directly affected by the rates, charges, rules, and other requirements that appear in these proposed tariffs and in Xcel's proposed form Energy Services Agreement (ESA). As the industry voice of the data center owners and operators that will take service on these tariffs, DCC is the only entity that can represent the unique interests of Xcel's current and future data center customers in this proceeding.

For these reasons, DCC requests that the Commission find that DCC has met the standards for intervention and grant DCC status as a party to this proceeding.

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DATA CENTER COALITION'S INITIAL COMMENTS

DCC appreciates the opportunity to provide comments in this proceeding on Xcel's July 16, 2025, Petition, which Xcel filed pursuant to the Commission's April 21, 2025, Order in Docket Nos. 24-67 and 23-212 and in compliance with Minn. Stat. § 216B.1622.

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I. Introduction.

The demand for digital services is at an all-time high, playing a vital role in Americans' daily routines. Our work, education, banking, shopping, and even medical care increasingly occurs online. Data centers are at the heart of this transformation, providing the essential digital infrastructure that supports the applications, platforms, and services we rely on every day, ensuring we remain connected in our modern lives and that businesses, organizations, and individuals can remain competitive and grow our 21st century economy.

With an average of 21 connected devices per household in the U.S.,[2] the role of data centers is expected to grow as consumers and businesses generate twice as much data in the next five years as they did in the past decade.[3] This growth is driven by the widespread adoption of cloud services, the proliferation of connected devices, and the rapid scaling of advanced technologies like generative AI, which alone could create between $2.6 trillion and $4.4 trillion in economic value globally by 2030.[4] If Minnesota continues to foster data center development through clear permitting, grid upgrades, and balanced rate structures, the State has an opportunity to lock in a resilient foundation for jobs, tax revenue, and statewide innovation for years to come.

In recent years, Minnesota has experienced a growth in interest from prospective data center companies, reflecting a broader national trend. As every segment of the economy becomes increasingly dependent on digital services, the development of data centers, which make those services possible, has accelerated across the country to meet those needs. Data centers can require

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[2] Deloitte "Consumers embrace connected devices and virtual experiences for the long term," September 5, 2023 https://www2.deloitte.com/us/en/insights/industry/telecommunications/connectivity-mobile-trends-survey/2023/connectivity-mobile-trends-survey-full-report.html.

[3] JLL, Data Centers 2024 Global Outlook, https://www.us.jll.com/content/dam/jll-com/documents/pdf/research/global/jll-data-center-outlook-global-2024.pdf.

[4] McKinsey, *How data centers and the energy sector can sate AI's hunger for power* (September 2024), https://www.mckinsey.com/industries/private-capital/our-insights/how-data-centers-and-the-energy-sector-can-sate-ais-hunger-for-power.

a significant amount of electricity to meet our collective demand for digital services. Those needs create both challenges and opportunities. On one hand, rapid load growth can challenge utilities to build the infrastructure required to serve those customers' demands in a timely manner while mitigating the risk of those investments to all customers. On the other hand, rapid load growth will generate significant new revenues for electric utilities, and those revenues can create downward pressure on the rates that all customers pay.

Addressing these challenges and leveraging those opportunities requires utilities, regulators, and all stakeholders to collaborate and develop balanced, durable regulatory solutions. It is therefore prudent for the utilities, regulators, and customers (including data center and other large load customers) to work together to develop reasonable, evidence-based terms and conditions for large load customers. Those terms must reasonably protect utility customers from the risk of stranded costs but must also support economic growth and reasonably allow large load customers the opportunity to do business in Minnesota. With these goals in mind, DCC respectfully requests that the Commission consider DCC's recommendations, as discussed herein and summarized in the next section.

II. Summary of Recommendations.

For the reasons discussed below, DCC respectfully recommends that the Commission take the following actions with respect to Xcel's Petition:

- Approve the following features of Xcel's proposal:
    - The Large General Time of Day Service tariff applies to all new customers over 100 MW, not just to data center customers.
    - Flexible security and collateral requirements tailored to each customer.
    - 24-month advance termination notice requirement.

    - Ability to assign the customer's ESA and Interconnection Agreement (IA) to another entity under reasonable terms and conditions.
    - Voluntary demand response options through the optional Large Peak Controlled Time of Day Service tariff and the Tier 1 Energy Controlled Service rider tariff.
    - Required participation in the Under Frequency Load Shedding (UFLS) program.
- Reject Xcel's incremental cost test proposal, which will result in discriminatory rates, and direct Xcel to ensure that the new large customer subclass covers its cost of service through traditional class cost of service studies in rate cases.
- Clarify that customers may ask the Commission to review any determination made by Xcel that their premises should be aggregated for purposes of determining the applicability of the Large Peak Controlled Time of Day Service.
- Establish a ten-year minimum contract term with an additional load ramp term of up to five years.
- Define the "Termination Fee Period" as the lesser of 36 months or the remaining months in the ESA.
- Modify the minimum bill provision of the Large Peak Controlled Time of Day Service tariff to apply only after the load ramp period has concluded.
- Clarify that large customers are only required to provide non-binding load forecasts annually if needed for a specific purpose.

III. Applicable legal standards.

As noted above, Xcel filed its Petition in response to the Commission's April 21, 2025, Order in Docket Nos. 24-67 and 23-212 (the IRP Order). Subsequent to the Commission's Integrated Resource Plan (IRP) Order, the Legislature passed, and Governor Walz signed into law,

Minnesota House File No. 16 (HF 16), which, among other provisions, directed the Commission to establish a very large customer class or subclass for each public utility.

Specifically, the Commission's IRP Order directed Xcel to file a tariff that included the following nonexclusive factors:

- "Ensure that all incremental costs attributable to super-large customers are assigned to the super-large class or sub-class.
- Provide electricity to the super-large class or sub-class that achieves each benchmark of the state's electricity standards under Minn. Stat. § 216B.1691.
- Include provisions to ensure that super-large customers financially commit to purchasing a certain level of electricity to protect non-super-large customers from the risk of stranded costs. Include provisions to ensure that all super-large customer-related incremental costs will be recovered over the life of the service agreement.
- Include provisions to ensure that, if the super-large customer ceases operations for any reason, all remaining financial commitments will still be paid."[5]

Minn. Stat. § 216B.1622, subd. 2, created by HF 16, establishes similar required outcomes for Xcel's large customer tariff that the Commission must consider as it evaluates Xcel's proposals:

> "(1) all costs attributable to the utility's very large customers not exempt under subdivision 3 [*i.e.*, existing very large customers] are assigned to the very large customer class or subclass determined by the commission under paragraph (a);
>
> (2) the electricity to be provided by the utility to a very large customer achieves each quantitative benchmark of the state's electricity standards under section 216B.1691, as

[5] IRP Order, Order Point 32.

demonstrated by a plan submitted by the utility to serve the additional load without recourse to requesting a delay or modification of these standards;

(3) the tariff or agreement contains protections necessary to ensure that other customers of the public utility are not placed at risk for paying stranded costs associated with the utility serving the very large customer; and

(4) any other outcome deemed important by the commission to ensure the tariff or agreement is in the public interest."

Accordingly, the Commission's task in this proceeding is to ensure that Xcel's proposed tariffs and proposed tariff modifications are consistent with both the Commission's prior directives in the IRP Order and the above statutory directives.

Further, in all rate-setting proceedings like this one, the Commission must ensure that Xcel's rates are just and reasonable. Specifically, Minn. Stat. § 216B.03 provides: "Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers." Minn. Stat. § 216B.07 further prohibits rate preferences and prejudices with respect to a specific customer: "No public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage."

IV. The Commission should continually evaluate ways to reduce utility costs for all customers.

DCC generally supports reasonable customer protection mechanisms that help reduce risks for utilities and their customers, as addressed below. However, it is important to recognize that risk is neither static nor one-sided. Data centers face major risks themselves when they invest in

such large, capital-intensive facilities, which are generally reflected in data centers' financing costs. Data center companies take a range of factors into consideration when making siting decisions and many maintain flexibility with their eventual location. If too many risks or unreasonable risks are shifted onto data center customers, they can often invest in less risky jurisdictions.

Fortunately, there are many ways that utilities and their regulators can reduce risks and encourage data center investments without shifting any risks to other utility customers. Specifically, DCC encourages the Commission to direct Xcel and the other regulated electric utilities in Minnesota to provide more transparency on the capacity they have available to serve data centers and greater certainty with respect to load studies and energization timelines. The Commission should also push the electric utilities to focus on the multitude of ways they can reduce costs for all customers such as deploying grid-enhancing technologies (GETs) to increase transmission capacity on existing infrastructure, as well as virtual power plants (VPPs) and robust demand response programs to reduce the cost of serving peak demand. Finally, the Commission should ensure that the utilities' authorized returns on equity (ROE), which are significant contributors to customer bills, are aligned with market standards and not higher than needed to provide safe and reliable service.

In short, while DCC recognizes that protections against stranded assets and fair cost allocation principles for large data center customers are necessary to protect other utility customers, the Commission has many tools in its regulatory toolbox to protect against rate increases for all customers that should be continually evaluated.

V. DCC supports many features of Xcel's proposed large customer tariffs.

DCC has engaged in similar large load tariff and related rate case proceedings in jurisdictions across the country, including in Indiana, Kansas, Michigan, Missouri, Ohio, Oregon

and Virginia. Based on DCC's experience in those dockets, many aspects of Xcel's proposed Large General Time of Day Service tariff and proposed optional Large Peak Controlled Time of Day Service tariff are consistent with emerging best practices for large load tariffs. DCC takes this opportunity to highlight these important features of Xcel's proposal that DCC supports.

A. Xcel's proposed Large General Time of Day Service and Large Peak Controlled Time of Day Service appropriately apply to all new customers over 100 MW.

First, DCC appreciates that Xcel's proposed new tariffs would apply to any customer with a demand over 100 MW.[6] This approach is consistent with both the Commission's IRP Order, which refers to "super-large customers" and Minn. Stat. § 216B.1622, subd. 2, which refers to "very large customers." The U.S. is experiencing a significant increase in power demand driven by several economic growth trends, including the onshoring of new manufacturing, widespread electrification of buildings, industry and transportation, hydrogen fuel production, and growth in demand for data center services. As noted by Lawrence Berkeley National Laboratory in the 2024 U.S. Data Center Energy Usage Report, "This surge in data center electricity demand … should be understood in the context of the much larger electricity demand that is expected to occur over the next few decades from a combination of electric vehicle adoption, onshoring of manufacturing, hydrogen utilization, and the electrification of industry and buildings."[7] While DCC agrees with Xcel that the vast majority of customers with demand over 100 MW are data centers, tariffs should be designed based on the costs that customers impose on Xcel's system, not based on the purpose for which customers use electricity. To avoid discriminating against different types of end-uses and to ensure that Xcel and Minnesota are prepared for all forms of future load growth, it is appropriate for the new tariffs to apply to all new customers that meet the size requirements.

[6] Xcel Petition at 9.
[7] Lawrence Berkeley National Laboratory, 2024 U.S. Data Center Energy Usage Report, December 2024, https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf.

DCC also supports Xcel's proposal to apply the new Large General Time of Day Service only to new customers that begin service after the effective date of the tariff and to existing customers that enter into a new agreement to expand their existing load after the effective date of the tariff.[8] As Xcel notes, this proposal is consistent with Minn. Stat. § 216B.1622, subd. 3, which states that the requirements of that subsection do not apply to "existing, renewed, or extended" ESAs or to large customers that have been taking service since prior to 2020. It is both reasonable and only fair to allow existing customers – that have already made critical business decisions and investments in Minnesota – to continue taking service on the rate schedules that currently apply to them and pursuant to the terms of their existing ESAs with Xcel.

B. Xcel's approach to security requirements provides crucial flexibility for large customers while protecting all other customers.

DCC recognizes the importance of requiring large load customers to provide some form of security to ensure they will meet their financial obligations under their ESA. To that end, the Commission's IRP Order required Xcel's large load customer proposal to ensure that, "if the super-large customer ceases operations for any reason, all remaining financial commitments will still be paid."[9] Similarly, HF 16 required Xcel's proposal to include "protections necessary to ensure that other customers of the public utility are not placed at risk for paying stranded costs associated with the utility serving the very large customer."[10] Xcel's proposed security requirements meet both of these directives.

Specifically, Xcel proposes to require sufficient security and collateral through the ESA with each large load customer, with the default mechanism being a parent company guarantee.[11]

[8] Xcel Petition at 10; Large General Time of Day Service, proposed Original Sheet No. 32.2.
[9] IRP Order, Order Point 32.
[10] Minn. Stat. § 216B.1622, subd. 2(3).
[11] Xcel Petition at 13 and Attachment G at 8.

While Xcel's proposed form ESA, which appears as Attachment G to Xcel's Petition, specifically requires a guarantor that either has a credit rating of at least BBB- or Baa3 or three billion dollars in cash on hand,[12] the Petition itself states that these are "examples of the types of security and risk mitigation measures that will be considered."[13] The data center industry is a dynamic one with many companies, varying company sizes, and several different business models. DCC appreciates that Xcel recognizes that each large customer's credit and financial situation is different and so there is no "one-size, fits-all" security requirement that will be appropriate for all large customers. As a result, it is reasonable to allow Xcel and the large customer to work together to develop an appropriate security requirement through the ESA negotiation process and present the proposal to the Commission for approval.

To help inform and guide both the security negotiations between large load customers and Xcel as well as the Commission's review of the security provisions of each ESA, DCC provides attached to these comments a recent whitepaper from Energy and Environmental Economics, Inc. (E3), "Balancing Risk and Growth: Best Practices for Utility Credit and Collateral Requirements for Large Load Customers."[14] Based on five core principles – balance, equity, optionality, scalability, and adaptability – E3 recommends four best practices for large customer security requirements:

1. Differentiate perceived vs. actual risk by assessing project maturity, sponsor strength, and contractual backing to avoid blanket conservatism.
2. Align credit with project maturity, using milestone-based requirements that scale with utility exposure.

[12] Xcel Petition, Attachment G at 7-8.
[13] *Id*. at 13.
[14] *See* Attachment A. This whitepaper is also available for download here: https://www.ethree.com/data-center-credit-collateral-whitepaper/.

3. Introduce optionality through a menu of acceptable credit tools, reflecting customer diversity while maintaining protections.
4. Avoid redundant risk mitigants by calibrating requirements and leveraging tools like a Credit Efficiency Index (CEI).[15]

Xcel's proposal to negotiate reasonable credit requirements with each large load customer is consistent with items 1 and 3 above because it focuses on the actual risks posed by each particular customer and project and provides optionality by accepting different types of credit tools. DCC encourages Xcel and the Commission to keep all four of these best practices, as well as the other insights and recommendations in the E3 whitepaper, in mind as they negotiate and review ESAs with large load customers.

C. Xcel's 24-month advance termination notice requirement is reasonable.

DCC recognizes the importance of requiring large load customers to provide notice to Xcel well in advance if they need to terminate their ESA early. Xcel's proposal to require at least 24 months' notice strikes the right balance of providing significant advanced notice to Xcel without being longer than necessary. An advance notice requirement longer than 24 months would not be compatible with most businesses' ability to forecast future operations. Given that Xcel likely has a long queue of large customer loads waiting to be energized, providing Xcel with 24 months' advance termination notice provides Xcel with plenty of time for Xcel to reallocate the departing customer's capacity to another customer in the queue that is seeking service.

D. DCC supports Xcel's proposed assignment clause.

DCC appreciates that Xcel has proposed to allow a large customer to assign the rights and responsibilities set forth in its ESA and IA to a successor or affiliate, subject to potential additional

[15] *Id*. at 1.

or different security and credit requirements that Xcel may impose and to which the new customer will need to agree.[16] Business plans can change and providing large customers with the option to assign their ESA and IA to another customer (with Xcel's agreement) reduces risks and provides flexibility that will encourage large customers to invest in Minnesota. Allowing large customers to assign their ESA and IA to another entity also provides benefits to other customers by helping to ensure that the revenues expected under an ESA materialize and by reducing the (already low) possibility that Xcel will need to rely on exit fees to collect these revenues.

E. DCC supports Xcel's proposal for voluntary demand response options for large customers.

DCC appreciates that Xcel has proposed the optional Large Peak Controlled Time of Day Service tariff and has proposed revisions to its Tier 1 Energy Controlled Service rider tariff to allow large load customers to participate. These two tariffs are voluntary, well-structured demand response programs that appropriately allocate risk, incentivize customers to participate by compensating them for participation, and help large load customers achieve their sustainability commitments.

Critically, DCC supports these demand response options because they are voluntary. Data centers have different degrees of flexibility with their loads and their ability to switch to backup power, with some data centers being quite flexible and eager to participate in demand response programs with the right incentives, and others requiring consistent levels of power throughout the day. DCC appreciates and supports Xcel's proposal to offer its demand response programs for large customers as voluntary options.

[16] Xcel proposed Large General Time of Day Service tariff, Original Sheet No. 32.7.

F. Xcel's proposal to require participation in the UFLS program is reasonable, but should not be understood to allow for lower levels of service.

DCC takes exception to Xcel's suggestion that large data center loads have the potential to cause disruptions on the grid.[17] Sound grid planning and management, along with utility-customer engagement, can help mitigate any grid challenges posed by large loads. With their relatively constant levels of demand and high load factors, data centers can be expected to contribute to grid stability. Nevertheless, DCC does not oppose Xcel's proposal to require large customers to participate in NERC's UFLS compliance program, which could result in disconnection if an under-frequency event occurs to help preserve grid stability.[18] However, the ability to disconnect large customers in the rare instance of an under-frequency event should not be understood as a replacement for the need for high levels of reliability and an appropriate reserve margin.

VI. The Commission should reject Xcel's incremental cost test proposal in favor of traditional class cost of service studies in rate cases.

DCC fully supports cost-based ratemaking and agrees with the fundamental principle that each customer class should pay for the costs the utility incurs to serve each class. Large customers should fully pay for the costs Xcel will incur to serve them and should not be subsidized by other rate classes. By the same token, large customers should also not subsidize other rate classes. That is not to say that large load customers will not benefit other customers – they will. By allowing Xcel to spread its fixed costs over a great volume of sales, adding large customers to Xcel's system will put downward pressure on rates for all customers. But this dynamic is not a cross subsidy. Rather, this downward pressure results from economies of scale and the utility's ability to spread the costs of shared system resources and shared system infrastructure across more customers and more sales.

[17] Xcel Petition at 14.
[18] *Id*. at 14-15.

A. Xcel's incremental cost test proposal violates standard ratemaking principles.

Though Xcel provides few details about how its proposed incremental cost test would work, its Petition describes a process in which Xcel will ensure that each large customer will subsidize other customer classes, potentially by requiring a large customer to pay fees that are unique to that customer and not set forth in any tariff. Specifically, Xcel states: "If the Incremental Cost Test shows that revenues are projected to be lower than incremental costs, then the customer and the Company will develop a proposal in the ESA to bring additional revenues such that incremental costs are paid for and a benefit is shown for system customers."[19] In other words, Xcel proposes to reserve the right to collect a surcharge from certain large customers, without ever specifying the amount of the surcharge in a tariff or explaining exactly how the surcharge will be calculated.

It is appropriate for Xcel to establish rates for the large customer subclass that will allow it to recover its costs of serving the large customer subclass. However, asking each large load customer to provide "additional revenues" through a surcharge – the sole purpose of which is to benefit other customers – is a blatant cross-subsidy. All customers, including large customers, should pay the utility's full cost of serving them. But no customer should be asked to provide the utility with additional revenues that exceed the cost of serving them. To do so would be to violate the prohibition in Minn. Stat. § 216B.07 against a utility charging rates that "subject any person to any unreasonable prejudice or disadvantage." Xcel also does not appear to have a mechanism in place that would ensure that excess revenues from large customers benefit other customers, rather than providing a windfall to Xcel's shareholders.

[19] *Id*. at 18.

Xcel points out that its Incremental Cost Test is the same tool it has used when it has brought forward prior ESAs for large customers,[20] but fails to mention that most (or perhaps all) of these ESAs established competitive rates pursuant to Minn. Stat. § 216B.162. That statutory section allows Xcel to offer a rate *reduction* to a customer that is subject to effective competition, provided the rate recovers "at least the incremental cost of providing the service."[21] Using an incremental cost test to ensure that a competitive customer's reduced rate is not so low that it results in a cross-subsidy to that customer is entirely consistent with standard cost-causation principles. However, applying an incremental cost test to a large customer to ensure that the customer's tariff-based rate is sufficiently high that it *will* result in a cross-subsidy to other customers violates those same principles. In short, the use of an incremental cost test in the context of competitive rates is not a justification for using them in the context of the tariffed rates at issue here.

Just as concerning, Xcel has proposed to apply "a bespoke incremental cost calculation" to each large customer, with the expectation that this calculation will "result in a unique incremental cost for each Large General Time of Day Service customer."[22] This proposal is an example of single-issue ratemaking at its worst; it is effectively ratemaking for a single customer. It also violates Minn. Stat. § 216B.03, which requires that utility rates be "consistent in application to a class of consumers." Allowing Xcel to impose different surcharges on different large customers will result in rates that are not consistent in application to the new Large General Time of Day Service subclass. Xcel's "bespoke" ratemaking approach would also likely result in similarly situated large customers paying very different effective rates based solely on when they began

[20] *Id*.
[21] Minn. Stat. § 216B.162, subd. 4(2).
[22] Xcel Petition at 17-18.

taking service from Xcel, an inequitable result that fails to meet the just and reasonable standard and violates the prohibitions on preferential and discriminatory rates found in Minn. Stat. §§ 216B.03 and 216.B07.

B. The Commission's and the Legislature's directives appropriately required Xcel to establish a new large customer class or subclass, not customer-specific rates.

Both the Commission's IRP Order and the legislature got it right when they directed Xcel ensure that its proposed large customer *class or subclass* pays its full cost of service. Specifically, the Commission's IRP Order required Xcel's tariff to: "Ensure that all incremental costs attributable to super-large customers are assigned to the super-large *class* or *sub-class*."[23] Similarly, Minn. Stat. § 216B.1622, subd. 2, directed the Commission to ensure that "all costs attributable to the utility's very large customers … are assigned to the very large customer *class* or *subclass*."[24]

Xcel's proposal to perform its "bespoke" incremental cost analysis on a customer-by-customer basis, rather than with respect to the entire Large General Time of Day Service subclass, finds no basis in either the Commission's IRP Order or statute. Further, neither the IRP Order nor Minn. Stat. § 216B.1622, subd. 2, requires large customers to pay more than their full cost of service, which is what Xcel's incremental cost test and surcharge proposal would do. Rather, both the order and the statute appropriately require the large customer class or subclass to pay the full incremental cost of serving them – nothing more and nothing less.

C. The Legislature already created a mechanism that requires large customers to subsidize low-income customers.

It is worth remembering that HF 16 requires a different, specific type of cross-subsidy from large data centers that will benefit low-income customers. Specifically, Minn. Stat. § 216B.72

[23] IRP Order, Order Point 32 (italics added).
[24] Minn. Stat. § 216B.1622, subd. 2(1) (italics added).

requires the Department of Commerce (the Department) to collect an annual fee from large-scale data centers based on their peak demand, with data centers between 100 MW and 250 MW paying an annual fee of $2 million, data centers between 250 MW and 500 MW paying an annual fee of $3 million, data centers between 500 MW and 750 MW paying an annual fee of $4 million, and data centers 750 MW and larger paying an annual fee of $5 million.[25] The annual fees paid by data centers will be deposited in the Department's energy and conservation fund and may only be used on low-income programs.[26]

This statutorily mandated, annual cross-subsidy from data centers to low-income customers for energy conservation programs ensures that large data center customers will provide benefits to existing low-income customers. This benefit, of course, is in addition to the downward pressure on rates that will result from Xcel spreading its fixed costs over a greater volume of sales. To the extent the Commission has any concerns that the rates and charges set forth in Xcel's proposed Large General Time of Day Service tariff will not result in sufficient benefits to existing customers, the fact that data centers will be providing large annual subsidies for low-income conservation programs should eliminate such concerns.

D. Traditional class cost of service studies in rate cases will ensure that the new large customer subclass pays its full cost of service.

Xcel's incremental cost test is a solution in need of a problem. Traditional ratemaking practices include a time-tested tool for ensuring that a class or subclass of customers is paying its full cost of service and is not being subsidized by other customers: a class cost of service study. By allocating a utility's overall revenue requirement to the various service classes based on the utility's relative cost of providing service to each class, a class cost of service study ensures that

[25] Minn. Stat. § 216B.72(b).
[26] Minn. Stat. § 216B.241, subd. 2a(c).

no class or subclass is subsidizing or being subsidized by the others. In its next rate case, Xcel can and should perform such a study to ensure that the revenues it receives from Large General Time of Day Service customers cover its costs of serving the customers in this new subclass. If Xcel's analysis indicates that the Large General Time of Day Service subclass is not generating sufficient revenues to cover the costs the subclass imposes on the system, Xcel can and should propose to increase the rates it charges Large General Time of Day Service customers. Any such proposal should be based on rigorous analysis of the subclass and standard cost allocation principles. This process is standard utility ratemaking practice and does not require "bespoke" customer-specific analyses or customer-specific surcharges to ensure that rates are just and reasonable.

For these reasons, the Commission should find that Xcel's incremental cost test proposal is not necessary and reject it. However, if the Commission approves the use of the incremental cost test (which it should not do), then at the very least the Commission should clarify that it will review Xcel's incremental cost test analysis for any large customer that requests such a review. Any customer asked to pay a surcharge on top of the rates set forth in the Large General Time of Day Service should have the opportunity to review Xcel's analysis that produced the proposed surcharge with complete transparency. If a large customer disagrees with Xcel's incremental cost test analysis or result, the customer should have recourse to the Commission to review the customer-specific incremental cost test. Otherwise, Xcel would have undue discretion to refuse to sign an ESA based on a disagreement about what level of surcharge or other payment is necessary to satisfy Xcel's own incremental cost test. Further, any customer that agrees to pay a surcharge through their ESA as a result of the incremental cost test should be permitted to ask Xcel and the Commission to revisit the surcharge at a future date to ensure it is still needed.

VII. DCC recommends several improvements to Xcel's proposal.

For the reasons stated above, Xcel's incremental cost test proposal is DCC's primary concern with Xcel's Petition. DCC also recommends several improvements and clarifications to Xcel's applicability proposal, proposed ESA language regarding the relationship between the tariff and the ESA, the exit and capacity reduction fees, the minimum demand charge, and the customer load forecasting requirement.

A. The Commission should require more transparency with respect to Xcel's proposal to aggregate premises under the Large Peak Controlled Time of Day Service tariff. For any customer whose loads are aggregated, Xcel must also aggregate the demand of all premises when calculating any minimum bill.

Xcel proposes to require any large customer with demand over 100 MW that initiates service after the effective date of the tariff to take service on the Large Peak Controlled Time of Day Service tariff.[27] Further, Xcel proposes to retain the right to use its discretion to aggregate the loads of multiple premises and require all premises to take service on the Large Peak Controlled Time of Day Service if the aggregated load exceeds 100 MW.[28]

Xcel's proposal to aggregate the loads of multiple premises does not reflect standard utility practice. For example, a large retailer with numerous stores and distribution centers could have a total aggregated load that, if aggregated, would push the retailer into a new rate class or subclass. DCC is not aware of any examples in which a utility has required such a customer to aggregate their loads and take service at all its premises on a tariff that would not otherwise apply to those premises.

[27] Xcel Petition at 10; Large General Time of Day Service, Original Sheet No. 32.2.
[28] *Id.*

Nevertheless, DCC does not oppose Xcel's aggregation proposal in principle. It is reasonable to treat a large customer as a single large customer even if that customer operates multiple premises that fall below the 100 MW threshold.

However, DCC opposes Xcel's proposal to retain discretion to determine unilaterally whether multiple premises should be aggregated and required to take service on the Large Peak Controlled Time of Day Service tariff. In particular, if the Commission accepts Xcel's incremental cost test proposal (which it should not do), DCC is concerned that Xcel could exercise this discretion in such a way that customers are unfairly asked to pay surcharges through their ESAs for not meeting Xcel's bespoke incremental cost test.

Accordingly, DCC recommends that the Commission clarify that customers may ask the Commission to review any determination made by Xcel that their premises should be aggregated for purposes of determining the applicability of the Large Peak Controlled Time of Day Service.

Further, the Commission should clarify that, for any customer premises that are aggregated and required to take service on the Large Peak Controlled Time of Day Service tariff, the actual measured demand of all premises should be aggregated for purposes of calculating the customer's demand charge, including any minimum bill based on contracted capacity. For example, if Xcel aggregates three customer facilities, two of which are operating close to their full contract capacity and a third that is operating at half of its contract capacity, Xcel should aggregate the measured demand of the three facilities when determining the customer's demand charges. Since Xcel has determined to treat the three facilities as a single customer, it would not be reasonable for Xcel to then charge the customer a minimum bill (75 percent of contract capacity) for the third facility. If Xcel requires a customer to aggregate multiple premises, then all aggregated premises should be

treated as one premise for all aspects of billing, including determining whether the minimum bill provision applies.

B. Xcel's proposed 15-year contract term length is longer than needed to protect customers.

Xcel proposes to require large customers to sign ESAs with an initial term of 15 years, which includes a load ramp period of up to five years.[29] While DCC appreciates that Xcel has proposed to include a load ramp period, its proposal to require a minimum of 15 total years for its ESA term is longer than needed to protect other customers. Xcel's proposed 15-year term is also inequitable because it effectively imposes longer contract terms on those customers that can agree to shorter load ramp periods. For example, a customer that requires a load ramp period of only two years will effectively be locked into 13 years of full contract capacity, while a customer that requires a five-year load ramp period will be locked into only ten years at full contract capacity.

Instead, DCC recommends requiring an initial ESA term of ten years, not including a load ramp period, and allowing customers to add a load ramp period of up to five years to the standard ten-year term. This term length is sufficiently long that it will "ensure that all super-large customer-related incremental costs will be recovered over the life of the service agreement," consistent with the Commission's directive.[30] Compared to a full 15-year term requirement, DCC's recommended "10+5" construct provides more flexibility to customers and is more equitable between large customers.

[29] Xcel Petition at 10; Large General Time of Day Service, proposed Original Sheet No. 32.2.
[30] IRP Order, Order Point 32.

C. The exit fee and capacity reduction fee should be based on a maximum of 36 months, which is sufficient time for Xcel to recover its costs or replace the customer.

DCC recognizes the importance of requiring an exit fee and a capacity reduction fee to protect the utility and other customers from the risk of stranded costs. DCC is not opposed to Xcel's proposal to calculate the exit fee based on 75 percent of the customer's current effective demand charges[31] and to calculate the capacity reduction fee based on 75 percent of the difference between the customer's contract capacity and the reduced capacity.[32]

However, DCC opposes Xcel's proposal to base the exit fee and the capacity reduction fee on a "Termination Fee Period" that is defined as the lesser of 120 months or the remaining months in the ESA.[33] Basing an exit fee and a capacity reduction fee based on up to ten years' worth of billing is excessive, unnecessary, and out of alignment with emerging best practices. Ten years is also far longer than Xcel will need to replace the departing customer's load with new load to mitigate any stranded costs, which means that a large exit fee or capacity reduction fee would simply provide a windfall to Xcel. Though no large customer plans to pay an exit fee or capacity reduction fee when they begin taking service, the risk that they might be required to pay such a large fee is likely to encourage many prospective large customers to consider investing in other states with less onerous exit fees.

For these reasons, DCC recommends that the "Termination Fee Period" be defined as the lesser of 36 months or the remaining months in the ESA. A termination fee period of 36 months is sufficient to protect Xcel and other customers without being longer than needed. It is worth remembering that this 36-month fee period is in addition to the two years of notice that a departing

[31] Xcel Petition at 11.
[32] *Id.*, Attachment G at 8-9.
[33] *Id.*

customer must give before terminating service. Further, to ensure that the termination fee does not simply become a windfall to Xcel's shareholders, Xcel should be required to undertake reasonable efforts to reassign the departing customer's capacity to a new or expanding large customer. To the extent Xcel can reassign the capacity to another customer, the costs that the termination fee is supposed to offset will be avoided or greatly reduced, which should trigger a refund of all or a portion of the departed customer's termination fee.

D. The minimum bill should be based on the contracted capacity after the load ramp period. Bills during the load ramp period should be based on actual demand.

DCC recognizes the importance of a minimum bill to protect customers from the risks of stranded costs and ensure that the revenues expected from a large customer materialize. DCC does not oppose Xcel's proposal to charge a minimum bill based on 75 percent of a customer's contract capacity.[34] However, this minimum bill provision should only apply after the load ramp period when the customer can be expected to be operating at its full contract capacity.

Charging a minimum bill based on the contract capacity that applies during each year of the load ramp period fails to recognize the purpose of the load ramp period is to allow both the customer and Xcel to build out capacity gradually over time. Because it is growing gradually, the customer's load at any given time during the load ramp period cannot be predicted with any precision. Xcel's proposed form ESA contemplates that Xcel and a customer would agree to an effective contract capacity that applies for an entire year of each year of the load ramp period,[35] but by definition a customer's actual demand is unlikely to be the same at the beginning of a given year as it will be at the end of the year during the load ramp period. Accordingly, charging a minimum bill based on a customer's estimated demand during the load ramp period greatly reduces

[34] *Id*. at 14.
[35] *Id*., Attachment G at Exhibit E.

the customer's ability to ramp up their load in a manner consistent with their business realities and partially undermines the purpose of having a load ramp period in the first place.

During the load ramp period, it is also possible that a large customer will not meet the contract capacity that applies for that year through no fault of its own but because Xcel has not completed the upgrades necessary for the customer to operate at that year's contract capacity. In such cases, it would be entirely inappropriate for Xcel to charge the customer a minimum bill based on the applicable contract capacity for that year.

For these reasons, DCC recommends that the minimum bill provision of the Large Peak Controlled Time of Day Service tariff apply only after the load ramp period has concluded.

E. Large customers should only be required to provide non-binding load forecasts annually if needed for a specific purpose.

Xcel proposes to require each large customer on the Large Peak Controlled Time of Day Service tariff to provide a non-binding load forecast every six months.[36] Xcel claims, without further explanation, that these forecasts will help "to reduce overall system costs."[37] Requiring large customers to provide non-binding load forecasts every six months is needlessly burdensome, especially given the vaguely defined purpose of such forecasts. That said, if Xcel can explain more fully in its reply comments the purpose for which it needs these forecasts, DCC would likely not oppose requiring large customers to provide non-binding load forecasts on an annual basis.

VIII. Conclusion.

DCC thanks the Commission for the opportunity to participate in this proceeding and submit these comments. DCC looks forward to responding to the initial comments of other parties and to any questions the Commission and other stakeholders may have.

[36] *Id*. at 15; Large General Time of Day Service, proposed Original Sheet No. 32.5.
[37] Xcel Petition at 15.

Respectfully submitted on October 13, 2025,

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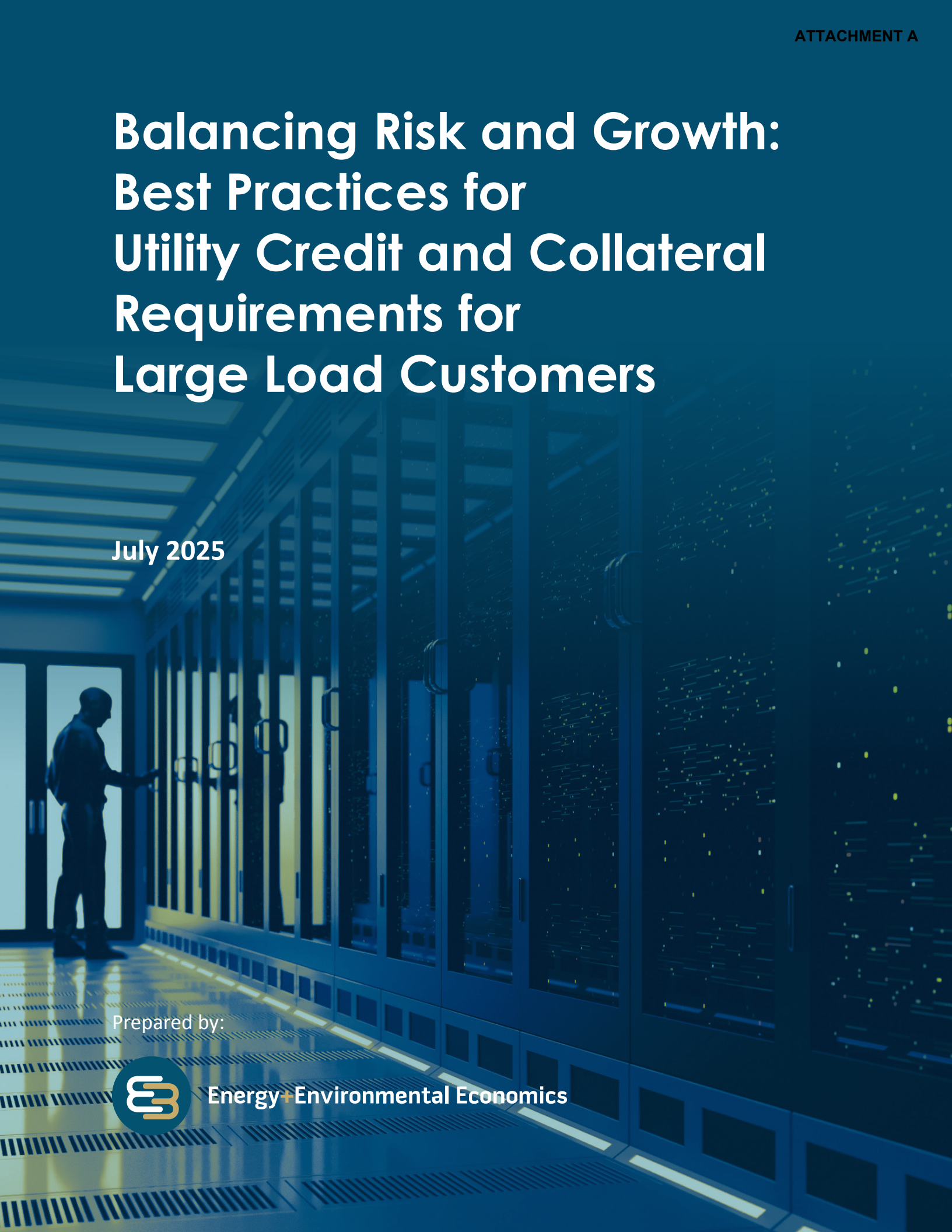
ATTACHMENT A

Balancing Risk and Growth: Best Practices for Utility Credit and Collateral Requirements for Large Load Customers



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Prepared by:

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Executive Summary

In an era of rapid load growth, utilities and regulators face growing pressure to modernize credit and collateral policies to manage risks while supporting continued economic growth. Many current approaches are built for smaller or riskier customers and often fail to reflect the financial strength and operational reliability of today's large loads such as data centers, which are typically backed by well-capitalized sponsors, long-term contracts, and high load factors. Utilities must still manage real risks such as stranded assets and nonpayment, making credit policies essential for protecting ratepayers and ensuring cost recovery. Moreover, in some markets, data centers likely represent the first of multiple waves of load growth, underscoring the need for adaptable policies to enable utilities to effectively meet the future needs of industrial growth, electrification, and other emerging demands.[1]

This whitepaper offers a modern and adaptable risk-aligned framework based on five core principles:

And highlights best practices that translate these principles into action:

1. **Differentiate perceived vs. actual risk** by assessing project maturity, sponsor strength, and contractual backing to avoid blanket conservatism.
2. **Align credit with project maturity**, using milestone-based requirements that scale with utility exposure.
3. **Introduce optionality** through a menu of acceptable credit tools, reflecting customer diversity while maintaining protections.
4. **Avoid redundant risk mitigants** by calibrating requirements and leveraging tools like a Credit Efficiency Index (CEI).

The paper also offers additional stakeholder-specific recommendations:

+ **Utilities** should adopt flexible, risk-based credit structures that evolve with project development and offer vetted credit options.
+ **Regulators** should promote transparency, stakeholder input, and regional coordination to ensure fair and scalable frameworks.
+ **Developers** should engage early, provide clear project information as relevant, and offer flexible credit alternatives to reduce risk.

In this era of rapid load growth, credit policy must evolve from a rigid safeguard into a strategic enabler of responsible, efficient infrastructure integration. This whitepaper provides a roadmap to achieve that goal while protecting ratepayers and supporting long-term grid resilience.

[1] These concepts are discussed in more depth in: I. Riu, D. Smiley, S. Bessasparis, K. Patel, "Load Growth Is Here to Stay, but Are Data Centers?: Strategically Managing the Challenges and Opportunities of Load Growth," Energy and Environmental Economics, Inc., July 2024. Available at: https://www.ethree.com/

Authors & Acknowledgments

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the power sector in North America. For over 30 years, E3's data driven analysis and unbiased recommendations have been utilized across the power industry by the utilities, regulators, government agencies, project developers, investors, and non-profit entities. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

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The views and opinions expressed in this whitepaper do not necessarily reflect views and opinions of the sponsor or any of their individual members.

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Defined Terms

Term	Definition
Collateral	Assets or financial instruments pledged to a utility to mitigate financial risk from customer nonperformance or default.
Credit Support	A broad category of financial assurances including collateral, guarantees, and bonds used to reduce utility exposure to customer financial risk.
Contribution in Aid of Construction (CIAC)	A nonrefundable upfront payment from the customer to help cover utility infrastructure or interconnection upgrade costs.
Commercial Operation Date (COD)	The date a facility becomes fully operational and begins delivering contracted load to the utility.
Energy Services Agreement (ESA)	Binding contract between a utility and a customer that defines service terms, cost recovery mechanisms, and obligations related to delivering and receiving electric service.
Engineering, Procurement, and Construction (EPC)	A company or contractor responsible for delivering a project under an Engineering, Procurement, and Construction (EPC) contract, managing all aspects from design through completion.
Interconnection	The process of connecting a customer's facility to the utility grid, involving planning, infrastructure upgrades, and regulatory approvals.
Letter of Agreement (LOA)	Document outlining specific commitments between a utility and a customer (e.g., funding studies) prior to executing interconnection/service agreements.
Letter of Credit (LOC)	A bank-issued guarantee that ensures payment to a utility in case of customer default; often required as a form of collateral.
Large Load	A large and often high-consumption customer, typically exceeding 10 MW and up to several hundred MWs, including data centers, crypto mining, industrial users, or manufacturing facilities.
Milestone-Based Collateral	Collateral that is posted incrementally as a project reaches defined development milestones (e.g., permit approval, EPC execution, COD).
Parent Guarantee	A credit assurance provided by a customer's parent company or corporate sponsor, backing the financial commitments of the project entity.
Performance Bond	A guarantee that is typically issued by a bank or insurer to ensure fulfillment of customer obligations or performance under a utility contract.
Prepayment	An upfront payment used by utilities to offset risk in early stages of customer interconnection; may function like a refundable or nonrefundable deposit.
Private Financial Assessments	E.g., third-party evaluates customer's financial health according to specific metrics such as debt service coverage ratio, EBITDA margins, etc.
Ratepayer	An end-use utility customer who pays for electric service and whose interests must be protected from cost shifting or stranded infrastructure risks.
Sponsor Support Agreement	A legal commitment from a project sponsor to cover shortfalls or defaults under specific conditions, often used in lieu of cash collateral, including committed growth equity
Stranded Cost / Stranded Asset	Infrastructure or investment that becomes unrecoverable due to customer nonperformance, load attrition, or project cancellation.
Surety Bond	A financial guarantee issued by a third-party insurer that compensates the utility if a customer fails to meet obligations.
Tariff	A formal utility rate schedule, contract, or set of terms approved by a regulator that governs customer pricing & requirements for electricity service.
Utility Capital Support	E.g., customer commitments to reduce the utility's financing needs, helping protect utility credit quality and expedite timelines.
Working Capital	Liquid financial resources a customer uses for operating expenses; can be constrained by large upfront collateral requirements.

The Context of Growth and Risk

In the early 20th century, unregulated and intense competition among electric companies led to redundant infrastructure buildout, with multiple providers constructing costly and duplicative networks in the same areas. As the model proved economically unsustainable, policymakers and industry leaders increasingly recognized that electric service exhibited the characteristics of a natural monopoly, where a single provider could deliver power more cost-effectively due to the high fixed costs and economies of scale involved in grid infrastructure. In response, the regulatory compact emerged - a framework in which utilities are granted legal monopolies in exchange for a commitment to serve all customers reliably and at just and reasonable rates, subject to oversight.

The electricity sector is now in a time of immense transition as it is being transformed by a number of economic growth trends, including the onshoring of manufacturing, the electrification of buildings, industry and transportation, hydrogen fuel production, renewable generation integration, and the digitization of the economy. In particular, with growth in data centers, driven by artificial intelligence (AI), cloud computing, digital services, e-commerce, and content delivery, the U.S. is entering a new era of load growth that is concentrated, nonlinear, and a distinct departure from the incremental, distributed patterns of the past 20 years.

The data center sector exemplifies this trend, with high load factors, long-term capital investments, and mission critical service demands. Backed by Fortune 100 sponsors or institutional investors, these data centers typically rely on long-term tenant contracts, power purchase agreements, and performance guarantees making them a creditworthy and stable load class once operational.

The rapid, large-scale growth of data centers, coupled with uncertain trajectories has created significant challenges for utilities. They face gigawatts of interconnection requests amid supply chain issues, capital investment and transmission gird constraints, with prolonged delays increasingly straining the system's ability to uphold commitments to timely and reliable service, further stressing the regulatory compact. Concerns about affordability, stranded assets, underused infrastructure, and unfamiliar counterparties are rising, making credit and collateral policies key risk management tools.

However, many existing financial policies were built for different contexts. Applying them uniformly to modern data centers can lead to overly conservative requirements, misaligned with actual risks, and may deter beneficial load growth.

Load growth, particularly from high-load factor customers such as data centers, can provide several benefits. Financially, large loads could help lower rates for all customers, as they allow utilities to spread their fixed costs over a higher sales volume, in addition to increasing and stabilizing utility revenue. From a grid reliability perspective, they can help support crucial investments in grid infrastructure which reduces aging infrastructure risks and improves overall service quality. Economically, they support local job growth, expand the tax base and spur regional growth and development. From a sustainability perspective, these loads can accelerate emerging clean energy deployment by serving as anchor customers for early-stage, higher-risk projects that advance utility decarbonization goals.

To address this challenge and mismatch of tools, utilities and regulators must distinguish between perceived risks that are often tied to unfamiliar models vs. actual risks, which can be objectively evaluated based on historical performance, project sponsors, contracts, and development stage.

This whitepaper proposes a modern credit and collateral framework built on five principles: Balance, Equity, Optionality, Scalability, and Adaptability. It outlines key risks for utilities and data centers, critiques current practices, and offers the following best practices for improvement:

+ Calibrate between perceived and actual risk,
+ Align credit requirements with project maturity for risk symmetry,
+ Provide optionality through a menu-based approach,
+ Avoid overlapping risk mitigants

The paper concludes with practical recommendations for designing effective credit and collateral requirements. Drawing on its experience with utilities, regulators, developers, investors, and policymakers, E3 offers guidance grounded in technical analysis and real-world market conditions.

Well-designed credit and collateral policies serve a dual purpose: protecting utilities and ratepayers from default risks while supporting the timely integration of essential infrastructure. Achieving this balance is key to ensuring that large load growth delivers broad benefits to customers, the grid, and the economy.

Core Principles for Collateral and Credit Support Design

As large loads like data centers play a growing role in utility planning, credit and collateral policies must adapt to reflect modern project dynamics, financial models, and risk profiles. Drawing on its national experience advising utilities, regulators, and developers, E3 has identified five core principles that underpin effective and lasting policy design. These principles guide E3's approach to crafting credit and collateral frameworks that align utility risk management with the realities of today's energy and infrastructure landscape.

Balance

Equity

Optionality

Scalability

Adaptability

Core Principles for Collateral and Credit Support Design

Balance

Are collateral requirements proportionate to actual risk?

Collateral frameworks should protect utilities and ratepayers from real financial exposure such as stranded assets or lost revenues without overcompensating for speculative or generalized concerns. E3 advocates calibrating risk based on project stage, sponsor quality, and capital investment.

A balanced approach:

+ Distinguishes between perceived and actual risk
+ Aligns collateral timing and size with utility exposure
+ Allows for collateral reduction or return as risk diminishes over time

Equity

Are data centers and other large loads treated consistently with utility precedent and regulatory norms?

Even as large loads like data centers bring new characteristics, credit and collateral policies should uphold foundational principles of cost causation and nondiscriminatory treatment. Equity ensures that all customers are held to consistent standards, regardless of sector. Further, equitable treatment within a sector can promote competition and diversity, avoiding choosing winners and losers within competitive industries.

An equity-focused framework:

+ Avoids arbitrary thresholds or burdens targeted at specific industries or customers
+ Reflects how utilities manage other large, high-load-factor customers (e.g., industrial, manufacturing)
+ Aligns with regulatory norms for fair access and cost recovery

Optionality

Are there multiple viable paths to meeting credit requirements that reflect the diversity of customer profiles and project structures?

A rigid, one-size-fits-all policy, such as mandating a letter of credit from an A-rated bank can exclude legitimate, creditworthy projects with alternative financial structures. Optionality introduces flexibility by offering a defined set of acceptable credit instruments for both utilities and large-load customers.

Key benefits of an optionality-based approach:

+ Provides multiple compliance options, such as Contribution in Aid of Construction (CIAC), surety bonds, or guarantees from parents, affiliated, tenant or 3rd party with financial interest in the customers
+ Enables utilities to tailor credit tools to specific risks (e.g., construction vs. operational risk) and stages
+ Reduces reliance on custom agreements, easing administrative burden and improving scalability
+ Creates a more diverse customer base for the utility which helps further derisk

Scalability

Can the policy framework apply consistently across multiple projects and over time?

With rising interconnection requests, particularly in high-growth regions, credit and collateral policies must be designed for administrative scalability. Effective frameworks should be repeatable, transparent, and capable of managing large project volumes without excessive customization.

Scalability involves:

+ Standardized criteria, documentation, and processes
+ Objective thresholds and milestone definitions
+ Streamlined application and compliance procedures
+ Efficient reuse of tools across projects
+ Clear, transparent expectations for all stakeholders

Adaptability

Can credit policies evolve in response to changing conditions, technologies, or regulatory environments?

As utilities adapt to rapid shifts driven by decarbonization, electrification, and digitalization, credit and collateral frameworks must remain flexible and forward-looking. Adaptability ensures policies can accommodate new project types and improve over time with experience and data.

Adaptable frameworks enable:

+ Periodic reassessment based on market trends, utility performance, or customer behavior
+ Risk-based triggers that adjust collateral in line with actual outcomes
+ Integration of emerging financial tools and mitigation strategies as they gain maturity

Applying the Principles

These five principles provide a foundational lens for E3's evaluation of credit and collateral frameworks for large loads. When applied collectively, they help ensure utility policies are:

+ Protective of ratepayers without deterring viable development
+ Fair and transparent across and within customer classes
+ Flexible to accommodate both established and emerging market needs now and into the future
+ Supportive of long-term investment and grid reliability

E3 encourages utilities and regulators to consider these principles when revising tariffs, crafting new credit structures, or formulating policies to effectively manage large load growth.

Utility Considerations: Credit Quality and Ratepayer Protections

A central goal of this whitepaper is to help utilities and regulators manage real financial risks while improving the alignment between credit requirements and actual customer risk, particularly in the context of accelerating large load growth.

This section outlines the primary utility concerns, with a focus on:

+ Credit quality and implications for financial exposure
+ Stranded cost risks, where infrastructure investments may not be fully recovered due to project delays, downsizing, or failure

Understanding these risks is essential for designing credit and collateral frameworks that are both protective and proportionate.

Utility Credit and Capital Efficiency

Utilities have legitimate concerns about protecting their credit ratings, avoiding regulatory disallowances, and maintaining capital efficiency. While traditional collateral tools like large, upfront letters of credit offer simplicity and a sense of security, they often fail to reflect actual risk exposure and can be inefficient or difficult to scale.

A more strategic, milestone-based credit framework can address these challenges while supporting beneficial load growth:

+ Mitigates stranded asset risk by aligning collateral requirements with project maturity and utility investment timelines
+ Improves capital efficiency through upfront contributions (e.g., CIACs or early-stage deposits), reducing utility outlay and improving cash flow
+ Enhances forecasting and planning via early coordination with large customers, supporting both capital allocation and credit evaluation processes

Offering flexible credit pathways can also reduce project drop-off and help convert more high-value, low-risk customers. In a competitive, capital-constrained landscape, rigid credit policies may cause project cancelation or drive viable projects to other jurisdictions leading to lost long-term revenues and underutilized infrastructure, both of which can weaken a utility's financial standing and hurt ratepayers.

By securing commitments from high-quality customers with strong counterparty profiles and long-term usage needs, utilities can strengthen their balance sheets, diversify their large ratepayer base, increase load factors, and reduce fixed-cost recovery risks which are outcomes that are generally credit positive.

Protecting Ratepayers

Safeguarding ratepayers is a core priority in designing interconnection policies, tariffs, and contract structures for large loads. Poorly designed or overly permissive credit policies can expose utilities and their customers to significant financial risks, including:

+ Stranded costs when projects are abandoned after prompting utility investments
+ Cost shifting to other customers if infrastructure is underused or not fully recovered through rates
+ Unpredictable exposure due to inconsistent or unclear credit requirements

The whitepaper's recommended approaches aim to reduce these risks without deterring beneficial load growth:

+ Milestone-based collateral structures ensure that customers take on risk at the time utilities commit capital, minimizing the chance of unrecoverable costs
+ CIACs and phased deposits offer early funding that directly reduces cost recovery burdens on the broader rate base
+ Performance-based collateral reassessments maintain protections if risk increases and offer relief as exposure declines

By adopting a risk-calibrated approach, utilities can distinguish between speculative ventures and credible projects, avoiding unnecessary overcollateralization that may otherwise block valuable, grid-enhancing development. This reduces the risk of forgoing long-term system benefits, lost revenues, and potential downward pressure on rates.

Utilities broadly share ratepayer protection goals, but their implementation of credit and collateral requirements varies, shaped by factors such as:

+ Institutional risk tolerance
+ Experience with large customers
+ System capacity constraints
+ Regulatory and policy mandates

Given this variability, applying consistent core principles is essential to crafting fair, effective, and adaptive credit frameworks that protect ratepayers while enabling strategic load growth.

Best Practices for Utilities

Grounded in the foundational principles above, these best practices help effectively address key pain points experienced by both utilities and customers. By improving transparency, infusing flexibility, and recognizing the diversity in large loads, these practices offer a fair and versatile framework for managing financial exposure while supporting timely and scalable interconnection.

1 Calibrate between Perceived vs. Actual Risk

2 Align Credit Requirements with Project Maturity for Risk Symmetry

3 Provide Optionality through a Menu-Based Approach

4 Avoid Overlapping Risk Mitigants

1 Calibrate between Perceived vs. Actual Risk

A common challenge in credit and collateral policy design is the disconnect between perceived and actual risk. While utilities rightly assess exposure from large loads, perceptions are often shaped by isolated cases rather than the strong financial and operational profiles of mature, commercially backed data centers. This can lead to overly conservative policies that deter viable projects. A more effective approach grounds risk assessments in objective factors such as sponsor strength, contracts, and project maturity ensuring requirements align with real, not assumed, risk.

Perceived Risks

Utilities and regulators are justifiably cautious about large, single-site loads due to concerns about stranded assets and financial disruption. Common perceived risks include:

+ **Project abandonment:** Speculative interconnection requests that stall, wasting resources.
+ **Uncertain backing:** Projects lacking committed tenants or solid financial support.
+ **Volatile models:** Association with boom-bust sectors
+ **Limited track record:** New entrants without utility experience seen as higher risk.

While valid in some cases, these concerns can often become the default lens for evaluating all large loads.

Actual Risks

As previously outlined, utilities face legitimate risks related to credit quality and ratepayer impacts. However, these risks can and are effectively mitigated through well-established tools such as CIACs to offset utility capital outlays, parent guarantees or sponsor support letters to provide a financial backstop, or demonstrated load ramps from comparable sites or markets to confirm delivery and operational capability.

Moreover, project risk diminishes over time as key development milestones are achieved and customers commit increasing levels of capital and collateral are factors that should inform how requirements are calibrated, as discussed in the next best practice. Once energized, data center loads typically exhibit very high load factors (i.e., 80%)[2], low volatility, and long asset lives which are characteristics that reduce utility risk and improve cost recovery over time.

The Disconnect

Risk levels vary significantly across customers, but many utilities apply blanket conservative credit requirements, often conflating speculative projects with well-capitalized, mission-critical infrastructure. As a result, even projects backed by Fortune 100 sponsors or long-term tenant commitments may face strict requirements, e.g. two years of prepaid collateral, simply due to their size or lack of precedent. This one-size-fits-all approach can deter investment, reduce ratepayer benefits, and discourage early, transparent engagement from developers who view the process as unpredictable or overly punitive.

Recommendations to Close the Gap

Utilities and regulators can close the risk-perception gap by focusing on practical, risk-calibrated solutions.

1. **Risk Education and Transparency:** Regulators and utility credit teams should invest in training to distinguish between different project types, sponsors, and milestones, and remove anecdotal evidence and confirmation bias from the equation.
2. **Project Maturity Scoring:** Utilities can implement a standardized readiness or maturity scoring framework to replace subjective or binary risk assessments.
3. **Segmented Customer Risk Categories:** Utilities should segment by sponsor strength, project stage, and business model rather than apply a uniform standard.
4. **Feedback Loop from Operational Experience:** Utilities already serving data centers should use real-world performance data to refine credit policies.

Grounding credit decisions in actual exposure, rather than generalized assumptions, can more effectively protect ratepayers while enabling responsible infrastructure growth at the pace the digital economy demands.

[2] Moss, Sebastian. “Silicon Valley Power Says Data Center Load to Double by 2035, Will Need Geothermal Power and Batteries.” Data Center Dynamics, Dec. 2023, https://www.datacenterdynamics.com/en/news/silicon-valley-power-says-data-center-load-to-double-by-2035-will-need-geothermal-power-and-batteries/.

2 Align Credit Requirements with Project Maturity for Risk Symmetry

Effective credit and collateral policies should reflect risk symmetry, which ensures that financial protections for the utility track the actual risk it bears at each stage of a project's development. This ensures safeguards are in place without placing undue burdens on customers during early project phases.

Moreover, credit and collateral requirements should not be static. Instead, they should evolve in phases, aligning with the customer's investment commitments, project maturity, and utility exposure over time. This approach provides a more transparent, proportional, and flexible framework for risk management.

Figure 1 plots the evolution of risk over a project lifetime from the perspectives of the customer and utility. Key activities are grouped into project phases that can serve as milestones triggering utility risk mitigation tools, such as CIACs and collateral. Importantly, this framework splits collateral into phases to better reflect the timing of utility risk and also includes a phase/trigger for the reduction or release of collateral once the site is operational. This stepwise framework ensures that collateral reflects the relative likelihood and financial consequence of project default or underperformance at each point in time.

Calibrating risk to developmental milestones encourages large load growth while ensuring "skin in the game" for developers as well as the utility. Utilities can use this risk-aligned framework as a base and adapt their internal processes and customer mix as needed.

Ultimately, risk symmetry is not about reducing safeguards, rather it's about aligning them with real risk. A phased framework better matches utility exposure with project maturity, supporting reliable grid planning and a more efficient interconnection process.

Benefits of a Risk-Symmetric Approach

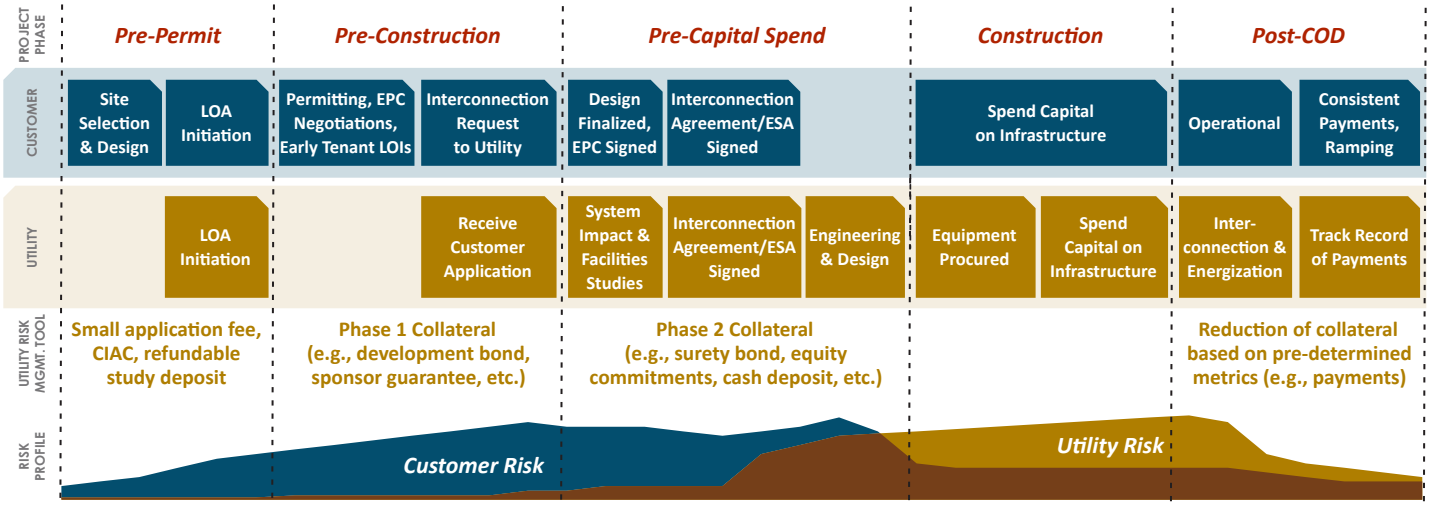
1. **Targeted Utility Protection:** Project risk is highest early in development, before permitting, contracts, or capital deployment. During this stage, utilities face exposure from engineering and planning costs. Initial deposits or CIACs can offset this risk without requiring long-term commitments. As customer investment grows and utility exposure shifts, collateral should transition to milestone-based requirements and decline once the project is operational and generating revenue.

2. **Encourages Project Discipline without Overburdening Early Stages:** Requiring full collateral upfront can deter viable projects and restrict cash flow. A phased approach distinguishes credible developments from speculative ones, encouraging commitment while preserving financial flexibility.

3. **Supports Mutual Derisking:** Phased collateral structures can resolve timing conflicts, such as those faced by colocation or multitenant data centers that need signed ESAs in order to secure tenants. Aligning collateral with actual project risk, such as tying it to pre-capital spend milestones, enables developers to move forward, improving certainty for both customer and utility.

4. **Improves Transparency and Predictability:** A milestone-based structure offers a clear roadmap for when and why financial requirements apply. This builds trust, reduces negotiation friction, and ensures consistent policy enforcement.

Figure 1: *Project Development Timeline from Utility and Customer Perspectives*



3 Provide Optionality through a Menu-Based Approach

One-size-fits-all policies, such as requiring an A-rated letter of credit (LOC) for all large loads, may simplify administration but often leads to overcollateralization which can impact the viability of projects, exclude creditworthy customers and limit the diversity of a utility's large customer rate base, and result in the underuse of utility capacity. For diverse data center projects, such rigid requirements can be misaligned with actual risk.

To resolve this, utilities should adopt a menu-based credit framework that offers a defined set of acceptable credit tools. This flexible approach lets customers meet requirements with instruments suited to their project profile, while maintaining transparency, financial discipline, and ratepayer protection.

Design Considerations for a Menu Framework

A well-designed menu-based credit approach should be standardized, transparent, and adaptable. Key elements include:

- Clear instrument list with defined eligibility
- Mix-and-match flexibility, allowing combinations of credit and deposit tools
- Milestone-based timing, aligning requirements with project progress
- Collateral adjustments based on performance or credit events
- Regular updates to reflect evolving market and regulatory conditions

Optionality does not weaken standards, rather it ensures rigor while accommodating customer diversity and system complexity. This approach enhances ratepayer protection, improves capital efficiency, and increases transparency, reducing delays and costs in large-load interconnection.

Aligning Credit Tools with Specific Risk

A menu-based framework enables utilities to match credit tools to distinct risk types, rather than applying one-size-fits-all solutions; this targeted approach creates a more proportional and defensible policy. Tools should be offered as flexible, combinable options, allowing customers to address risk effectively while meeting requirements. Table 1 provides examples of best fit credit tools for each risk type, and the table of Defined Terms provides additional detail on these tools.

Overall, menu-based credit policies offer a scalable, risk-informed alternative to rigid standards, enabling utilities to integrate large loads responsibly while maintaining financial integrity.

Table 1: *Best Fit Credit Tools by Specific Risk Type*

Risk Type	Best-Fit Credit Tools
Project readiness	This risk can be addressed by forms of upfront payment/deposits: ▪ CIAC ▪ Development deposits ▪ Milestone-based or phased collateral
Credit-worthiness	Alternatives to credit rating such as: ▪ Parent, affiliate, tenant, or 3rd parties with a financial interest in the customer guarantees ▪ Surety bonds ▪ Net worth thresholds ▪ Private financial assessments ▪ Utility capital support
Operational default risk	Alternatives to liquidity and credit rating such as: ▪ Contingent equity / sponsor support agreements ▪ Performance bonds ▪ Payment history ▪ Bespoke insurance product or escrow mechanism
Ramp risk or delay	This risk is often addressed with credit and non-credit tools such as: ▪ Link collateral reduction/release to key load milestones ▪ Minimum demand charge ▪ Contract minimum or "take-or-pay" provision ▪ Phased interconnection, aligning utility investment with customer load milestones

Why Optionality Matters

1. **Supports Diverse Customer Types:** Large load customers vary in structure and credit profile. Optionality allows utilities to tailor credit tools such as parent guarantees, milestone-based deposits, or alternative funding evidence which helps match project specifics, encouraging broader participation and better risk alignment. A more diverse customer base helps the utility further derisk, and overly stringent and rigid policies could limit the ability to fill any unused capacity.

2. **Adapts to Evolving Project Risk:** As projects mature, risk declines. Flexible collateral structures can start conservatively (e.g., CIACs), then scale down as construction progresses and performance is demonstrated to ensure protections align with actual exposure.

3. **Encourages Financial Innovation:** Menu frameworks support the use of alternative tools like surety bonds, insurance products, and hybrid models (e.g., partial deposits plus guarantees). These improve financial flexibility while preserving safeguards, which is especially valuable in capital-intensive sectors like data centers.

4. **Reduces Burden and Builds Trust:** Transparent menus streamline compliance, reduce the need for case-by-case exceptions, and improve predictability which can accelerate timelines and enhancing developer confidence.

4 Avoid Overlapping Risk Mitigants

Credit requirements often combine multiple tools (e.g. LOCs, CIACs, guarantees, and milestone deposits) to cover various risks. While each serves a purpose, applying them without a clear framework can create unnecessary redundancy. This overlap can lead to overcollateralization, tying up customer capital, slowing or canceling projects, and increasing attrition risk. For utilities, excessive layering may seem protective, but can obscure actual exposure, reduce transparency, and hinder scalability. Table 2 provides some examples of these potential redundancies.

Table 2: *Examples of Overlapping Risk Tools*

Risk Tool	Risk Mitigated	Potential Overlap
CIAC	Stranded infrastructure cost	Often addresses same risk as collateral aimed at default
Milestone-Based Collateral	Development risk, default before COD	Should scale down as CIAC and contracts are secured
Parent or Sponsor Guarantee	Counterparty risk	Redundant if CIAC and tenant contracts are in place
Letter of Credit (LOC) or Surety Bond	Broad performance assurance	Should not be additive to other secured risk-specific tools
Minimum Bill or Demand Guarantee	Revenue stability	May offset need for full credit-based collateral post-COD

While each credit tool is valid on its own, many can substitute for one another if properly structured. A sound framework should recognize existing derisking measures and avoid layering requirements unless clearly justified.

Introducing a Credit Efficiency Index (CEI)

To better align credit requirements with actual risk, E3 proposes a Credit Efficiency Index (CEI), which is a conceptual framework to assess overlapping risk mitigants and guide more efficient credit structures.

The CEI assigns weighted scores to key derisking factors, such as CIAC coverage, sponsor strength, development stage, stranded cost risk, demand guarantees, and operational track record. Higher scores signal lower risk and justify reduced or phased collateral; lower scores suggest a need for stronger safeguards.

This approach supports consistent, transparent, and risk-based credit policies to help utilities focus protections where truly needed, streamline negotiations, and treat customers equitably.

A Calibrated Approach, Not Risk Stacking

Recognizing overlapping protections is not about removing safeguards, rather it's about applying them proportionally. Utilities and regulators can improve credit policy effectiveness by:

+ Creating internal offset or equivalency tables for risk tools
+ Using a CEI-like framework to tier credit requirements
+ Embedding reassessment triggers as projects progress

A calibrated approach maintains financial discipline and protects ratepayers while supporting timely, capital-efficient load interconnection. An example CEI scorecard is provided in the Appendix.

Conclusion: A Path Forward

A principles-based and flexible framework for credit and collateral design enables utilities, regulators, and large-load customers to responsibly balance financial risk with economic opportunity. By grounding policies in fairness, transparency, and risk alignment, stakeholders can avoid two common pitfalls: overly conservative credit and collateral requirements that deter viable investment, and underpricing risk in ways that expose utilities and ratepayers to financial harm.

This whitepaper presents an updated approach and high-level framework to credit and collateral policy tailored to today's landscape. The recommended practices, including menu-based credit options and risk symmetry, are designed to help utilities on behalf of their customers and shareholders (if applicable) manage real risk while enabling the timely and efficient integration of large, capital-intensive loads like data centers.

For Utilities

Utilities are encouraged to adopt a structured yet flexible approach to credit and collateral that supports risk management, regulatory defensibility, and enables load growth. Specifically, utilities should:

+ Align collateral requirements to clearly defined project risk milestones (e.g., financial close, EPC execution, tenant signings) and use phases as applicable.
+ Accept diverse, pre-vetted forms of collateral, including surety bonds, parent guarantees, and sponsor support agreements.
+ Recognize the credibility and financial strength of well-capitalized customers and offer exemptions where justified, by calibrating across perceived vs. actual risk and leveraging optionality.
+ Implement reassessment mechanisms that reduce collateral obligations as projects demonstrate performance to correct for overlapping risk mitigants and maintain risk symmetry.

Transparent and standardized credit frameworks modeled on power supply contracts or interconnection service agreements can reduce ambiguity, support internal consistency, and improve confidence among both utilities and customers.

For Regulators

Regulators play a central role in ensuring that utility credit policies are risk-aligned, fair, and adaptable. Commissions should:

+ Require that credit and collateral levels be clearly justified based on quantifiable utility exposure.
+ Ensure consistency across similar customer types and avoid discriminatory treatment.
+ Encourage stakeholder input, case study development, and policy experimentation through pilot programs.
+ Support policy reassessment through regular updates tied to changes in load forecasts, performance data, and market conditions.

By providing guardrails that balance prudence with flexibility, regulators can enable more resilient and investment-friendly interconnection policy across their jurisdictions.

For Data Center Developers

Data center developers have a critical role to play in the implementation of risk-aligned credit policies. As utilities evolve their frameworks, developers can contribute to more effective outcomes by:

+ Engaging proactively and transparently with utilities, providing clear documentation of financial backing, tenant commitments, and project maturity.
+ Preparing multiple compliant forms of credit support including combinations of sponsor guarantees, CIACs, or milestone-based collateral.
+ Demonstrating long-term commitment to system use through performance history and regular communication on ramp-up progress.
+ Collaborating constructively on policy design efforts, especially in regions with limited prior experience serving large loads.

Well-prepared developers who clearly articulate their risk profile and project readiness will benefit from frameworks that distinguish credible infrastructure from speculative proposals ensuring fair treatment, timely interconnection, and long-term operational certainty.

Final Note

As demand and infrastructure investment surge, credit and collateral policies will be central to enabling scalable, reliable interconnections. These policies must balance real financial risks with transparency, adaptability, and economic growth.

This whitepaper outlines a flexible, risk-aligned framework that protects ratepayers, supports financial discipline, and accommodates diverse customers to ideally lay the groundwork for consistent, effective utility-customer engagement.

By adopting these best practices, stakeholders can transform credit policy from a barrier into a strategic tool for grid resilience and long-term value.

Appendix

Illustrative Credit Efficiency Index Scoring Framework

The Credit Efficiency Index (CEI) is a sample framework to help utilities transparently assess the overall financial readiness and risk profile of a large-load customer project. The CEI score can inform scaled collateral requirements by translating upstream project commitments into a simple, auditable risk score.

Interpretation

- **75–100 Points (Low Risk):** Eligible for lowest collateral tier or exemption with CIAC and minimum bill in place.
- **50–74 Points (Moderate Risk):** Milestone-based collateral or hybrid instruments required.
- **Below 50 (Higher Risk):** Full upfront collateral and/or performance security required.

Utilities may use CEI scores to tailor credit requirements proportionally while maintaining transparency and risk discipline. This approach supports scalable, replicable decision-making aligned with project-specific derisking characteristics.

Note: This is a conceptual tool meant to be illustrative. Utilities and their regulators should continue to define their own thresholds, weights, and documentation requirements.

Scoring Matrix *(Out of 100 Points)*

Category	Criteria	Points
1. CIAC Contribution	≥65% of utility capital cost	15
	40–64% of capital cost	7
	<40% of capital cost	0
2. Minimum Contract Term / Demand Guarantee	≥7-year contract with minimum annual demand	15
	3–6 years with soft demand commitment	7
	<3 years or no commitment	0
3. Development Stage	COD within 18 months and EPC executed	15
	Permits secured, EPC not yet executed	7
	Pre-permit	0
4. Sponsor Financial Strength	Investment-grade rated parent OR $1B+ private equity sponsor	15
	Mid-sized sponsor with liquidity disclosure	7
	Thin-cap or new developer	0
5. Historical Performance / Portfolio Maturity	3+ operational projects with strong utility history	15
	1–2 projects in service	7
	First-time interconnection	0
6. Stranded Asset Reusability	Infrastructure highly reusable (e.g., core substation/ shared feeder)	12
	Partially reusable (e.g., shared line capacity, moderate switching options)	6
	Dedicated or custom-built with low to no ability to repurpose / reuse	0
7. Stranded Cost Materiality	<10 MW and/or <$5M investment impact	13
	10-50 MW or $5M-$20M infrastructure investment	6
	>50 MW and/or >$20M investment at risk	0

CERTIFICATE OF SERVICE

I, Alicia Zaloga, hereby certify that on the 13th day of October 2025, I e-filed with eDockets the attached *Petition to Intervene and Initial Comments of Data Center Coalition* and served a true and correct copy of the same upon all parties listed on the attached service list by email, electronic submission, and/or mail.

Dated: October 13, 2025 */s/ Alicia Zaloga*

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