Large Load Policy Guide

TO: NEW MEXICO PUBLIC REGULATION COMMISSION

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RE: BEST PRACTICES FOR LARGE LOAD TARIFFS

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I. Introduction

Large load customers, particularly data centers and cryptocurrency mining facilities, have the potential to provide economic and utility system benefits, including increased sales that may help spread fixed costs over a larger customer base. At the same time, these customers often require substantial investments in electric system infrastructure to serve their large and concentrated loads.

If customer protections and cost allocation methods are not appropriately designed, existing customers may bear costs associated with serving large load customers or face increased risk if anticipated loads fail to materialize. Utilities and regulatory commissions are therefore adopting a range of mechanisms to recover the incremental costs associated with serving large loads, minimize the risk of stranded investments, and protect existing customers. This memo discusses best practices for achieving these objectives through tariff provisions, service agreement terms, and cost allocation practices.

Issues often accompanying large loads include:

- **Stranded cost risk:** Large load customers may reduce or terminate service before the utility has fully recovered the costs of facilities constructed to serve them because of changes in business conditions, technological developments, bankruptcy, or other unforeseen circumstances. Early customer departure can leave utilities with stranded investments and shift unrecovered costs to remaining customers.
- **Load uncertainty**: Large load customers often ramp up over time and may not ultimately achieve projected demand levels. In addition, changes in technology, market conditions, or business strategies can substantially alter future electricity consumption. This uncertainty complicates infrastructure planning and the design of cost recovery mechanisms.
- **Cost responsibility**: In addition to the direct costs of interconnecting large load customers, serving these customers may require upstream investments in generation, transmission, and distribution facilities. Cost allocation should ensure that the customers driving these investments bear an appropriate share of the associated costs.
- **Alignment with state energy and environmental policies:** Large load customers may bring their own generation or install behind-the-meter generation to supplement their electricity supply. Where that generation relies on fossil fuels, it may increase emissions and undermine achievement of state clean energy and climate goals.
- **Transparency of service arrangements**: Many jurisdictions serve large load customers under publicly available tariffs that establish standardized rates and terms. In some jurisdictions, large load customers enter into special contracts with the utility, which may be partially or fully confidential. The level of transparency can affect regulatory oversight and stakeholders' ability to evaluate whether the terms appropriately protect existing customers.

II. Best Practices for Large Load Tariffs and Contracts

Utilities and regulators can incorporate provisions into large load tariffs and service agreements that protect utilities and existing customers while providing certainty for large load customers. The mechanisms described below are intended to reduce stranded cost risk, improve cost recovery, and ensure that customers bear the costs they impose on the electric system.

1. **Contract term:** The contract term defines the period of time a customer is contractually obligated to abide by the terms of the tariff. Contract terms should be long enough to allow the utility a reasonable opportunity to recover the incremental costs incurred to serve the customer. Longer contract terms reduce the risk that the utility is unable to fully recover its investment, particularly for long-lived electric system assets.

    a. **Best practice**: Establish minimum contract terms of 15-20 years for large load customers. In general, larger loads and larger infrastructure investments warrant longer contract terms.

2. **Load aggregation rules:** Large customers may operate multiple facilities or meters within the same geographic area. Without aggregation rules, customers may be able to divide their load among multiple accounts to avoid qualifying for a large load tariff. Aggregation provisions ensure that affiliated or co-located facilities are treated as a single customer for tariff eligibility purposes.

    a. **Best practice**: Require co-located large loads operating under a single entity to be aggregated for the purposes of the tariff.

3. **Exit fees:** Exit fees require customers that terminate service before the end of their contract term to pay some or all of the utility's remaining unrecovered costs. Properly designed exit fees reduce stranded cost risk while allowing customers flexibility if business circumstances change. Some tariffs permit customers to transfer reserved capacity to a replacement customer, reducing or eliminating the exit fee if the utility continues to recover its costs. Allowing capacity reassignment incentivizes the original customer to find a replacement customer and reduces the risk of stranded costs.

    a. **Best practice:** Large load tariffs should include an exit fee designed to recover all remaining unrecovered costs. Tariffs should also include provisions that allow customers to reassign some or all of their capacity to a new customer, thereby reducing the exit fee.

4. **Collateral requirements:** Collateral protects the utility if a customer abandons a project, defaults on its obligations, or becomes insolvent before the utility has recovered its investment. Forms of collateral include cash deposits, a letter of credit from a bank, surety bonds such as from an insurance company, escrow accounts, payment guarantees from a parent company, and marketable securities such as U.S. Treasury securities. Collateral requirements may be reduced over time (or refunded in the case of a cash deposit) as the customer begins taking service and contributing revenues that offset the investments. Some tariffs allow large load customers to

bypass collateral requirements if they have a certain credit rating or meet a minimum balance; however, this practice provides less protection than cash or letters of credit.

   a. **Best Practice**: Require collateral sufficient to cover the utility's expected unrecovered incremental costs. Cash deposits and irrevocable letters of credit generally provide the strongest protection.

5. **Contributions in aid of construction, or upfront payments:** Upfront payments, or contributions in aid of construction (CIACs), are often required before the customer can begin taking service from the utility. CIACs seek to ensure that the new customer covers the costs of the infrastructure for which they are the sole beneficiary, and that other ratepayers do not subsidize these costs. Many utilities offset all or a portion of these contributions through line-extension allowances based on projected future revenues. While such allowances may be appropriate for traditional customer growth, they increase the risk that existing customers will subsidize infrastructure constructed primarily for large load customers.

   a. **Best Practice**: Require CIACs or some other form of upfront payment for all infrastructure for which the new customer is the sole beneficiary. Do not offset these payments through line extension allowances.

6. **Demand charge:** Demand charges recover costs associated with maintaining sufficient capacity to serve a customer's peak demand. Large load tariffs frequently include minimum billed demand provisions or demand ratchets to ensure recovery of demand-related costs even when actual demand falls below projections during ramp-up or subsequent operations. A demand ratchet requires a customer to pay based on the greater of their previous month's demand, or a fraction of their historical peak demand over a pre-determined historical period. Some tariffs also include a minimum billed demand requirement based on a specified percentage of the customer's contracted or reserved capacity. Even after a facility is fully operational, there is a risk that large load customers will never fully reach their anticipated demand. Demand ratchets and minimum billed demand requirements are a way to ensure the utility can sufficiently recover demand-related costs even if the customer's actual demand is lower than anticipated.

   a. **Best Practice**: Establish a minimum billed demand requirement based on a specified percentage of the customer's contracted or reserved capacity.

7. **Load factor:** Load factor measures how consistently a customer uses electricity over time by comparing average demand to peak demand. Different types of large load customers can have significantly different load characteristics. Tariffs that recognize these differences are more likely to recover costs appropriately than a single tariff designed for all large loads. Data centers typically have a very stable load, corresponding to a high load factor, while crypto mining facilities typically have greater fluctuations, corresponding to a lower load factor. Some tariffs include a load factor requirement which helps ensure that customers are taking service under the correct tariff.

   a. **Best Practice**: Avoid one-size-fits-all tariff design. Instead, design tariffs to apply to customers within specific load factor ranges to facilitate appropriate cost allocation.

8. **Ramp up period:** Many large load customers require several years to reach projected operating levels. During this period, actual demand may differ substantially from forecasts, increasing uncertainty regarding cost recovery. Tariffs may establish both a maximum ramp-up period and minimum demand milestones to ensure customers progress toward their contracted capacity (e.g., 50% in year one, 70% in year two, 90% in year 3, 100% by year four).
   a. **Best Practice**: Set a 3-5 year limit on the duration of the ramp up period until the customer is expected to reach full capacity, and establish a monthly billing demand schedule that increases over time until the end of the ramp up period.
9. **Clean energy requirements:** Many states have mandated clean energy or emission reduction targets. By including requirements governing behind-the-meter (BTM) generation, renewable energy procurement, or other dedicated resources, regulators can ensure that large load customers' resource decisions are consistent with state objectives. For example, some utilities have riders that offer capacity or energy credits or renewable attributes to large load customers that invest in clean resources (BTM generation or purchased power agreements (PPAs)). Utilities can also leverage special contracts to establish specific clean energy requirements for individual customers.
   a. **Best Practice**: Utilities should require that dedicated resources for large load customers, including BTM generation, PPAs, or distributed energy resources, comply with applicable clean energy and emissions requirements.

Summary of Best Practices for Large Load Tariffs and Contracts

Mechanism	Description	Best Practice	Example(s)
Contract term	The period of time a customer is contractually obligated to comply with the terms of agreement.	Service agreements should set minimum contract terms of 15-20 years for large load customers. The larger the load, the longer the term.	• Consumers Energy: 15-year term[1] (Status: approved) • Kentucky Power: 20-year term for loads >150 MW[2] (Status: approved) • Appalachian Power Co. (WV): no less than 12 years following the load ramp period, which can be no greater than 5 years.[3] (Status: approved)
Load aggregation rules	Specifications regarding how co-located load is treated.	Require co-located large loads to be aggregated for the purposes of the tariff.	• Indiana Michigan Power: Individual customers with 70 MW+ contract capacity, or 150 MW+ on an aggregated basis. Aggregated premises are defined by the Commission if premises share a common owner(s), a common parent company, common local electrical infrastructure, or common control.[4] (Status: approved)
Exit fees	An amount the customer must pay upon terminating service.	Exit fees should include all remaining unrecovered costs and encourage customers to reassign some or all of their capacity to a new customer.	• Consumers Energy: The exit fee equals the combined minimum monthly bill for the remaining contract period.[5]

[1] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001ORFPlAAP

[2] https://psc.ky.gov/pscscf/2024%20cases/2024-00305//20240830_Kentucky%20Power%20Tariff%20Filing.pdf

[3] Appalachian Power Company, West Virginia, Schedule L.C.P. (Large Capacity Power Service), effective September 29, 2025, available at: https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/Danville_Tariff_Sheets_Eff_6-1-26.pdf.

[4] https://synapseenergyeconomics.app.box.com/file/2287059591839

[5] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001ORFPlAAP

Mechanism	Description	Best Practice	Example(s)
Collateral requirements	A demonstration that the customer can pay the remaining costs owed in case of bankruptcy or financial distress.	At a minimum, collateral should cover the unrecovered incremental costs imposed by the customer.	• Ohio AEP: if the customer doesn't have both a credit rating of at least A- from S&P and A3 from Moody's and cash/cash equivalents greater than ten times the Collateral Requirement, they must provide a payment guarantee or collateral equal to 50% of the total minimum charges for the full term of the contract.[6] (Status: approved)
Contributions in aid of construction (CIAC)	Financial contributions paid by the customer upfront or over a period of time for incremental costs.	Require customers to pay CIAC for all infrastructure required to serve them directly, including feasibility studies and transmission costs, without subsidization from other customers.	• Xcel Energy (WI): new large load customers required to pay 100% of substation and distribution facility costs prior to energization.[7] (Status: proposed)
Demand charge	A charge based on a customers' maximum demand in a given period.	Establish minimum billed demand requirements, potentially including a demand ratchet based on a percentage of historical peak demand	• Kentucky Power: minimum monthly billing demand of at least 90% of the greater of the customer's on-peak contract capacity, or the highest monthly billing demand in the past 11 months, or the maximum demand during the billing month.[8]

[6] https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/June_2026_AEP_Ohio_Tariff_Book.pdf

[7] https://app.halcyon.io/documents/4f1faaff-4fc4-41f8-af4a-2d7ddac5fd14/attachment/file

[8] https://psc.ky.gov/pscscf/2024%20cases/2024-00305//20240830_Kentucky%20Power%20Tariff%20Filing.pdf

Mechanism	Description	Best Practice	Example(s)
Load factor	A measure of the stability of a customer's demand, calculated as the ratio between average demand and peak demand.	Setting minimum load factor requirements creates more certainty around month-to-month cost recovery	• Dominion (VA): customers taking service under the large load tariff must have a measured or expected load factor of at least 75%.[9] (Status: approved)
Ramp up period	The period of time before a customer reaches their full operating capacity. Consumption during this time can be unpredictable.	Set a 3-5 year limit on the duration of the ramp up period and establish a monthly billing demand schedule that increases over time until the time when the customer is expected to reach full capacity.	• Ohio AEP: four-year ramp up period, load shall be no less than 50% in the first year, 65% in the second year, 80% in the third year, 90% in the fourth year (% of contract capacity).[10]
Clean energy requirements	Requirements regarding the mix of generation installed by large load customers (including restrictions on BTM fossil generation).	Customer generation (including BTM generation) should meet state RPS targets.	• Oregon: HB 3546 requires the Commission to consider whether proposed large load tariffs impede the electric company's ability to meet State clean energy and emission reduction targets.[11] • Xcel (CO): large load customers can opt into the Clean Transition Tariff and receive bill credit for certain clean resources.[12] (Status: proposed)

[9] https://www.scc.virginia.gov/docketsearch/DOCS/84s%2301!.PDF

[10] https://www.aepohio.com/lib/docs/ratesandtariffs/Ohio/June_2026_AEP_Ohio_Tariff_Book.pdf

[11] Oregon Legislative Assembly, House Bill 3546 Section 2(3), effective June 16, 2025, available at: https://olis.oregonlegislature.gov/liz/2025R1/Downloads/MeasureDocument/HB3546/Enrolled.

[12] Hearing Exhibit 102, Attachment MVP-1, Clean Transition Tariff, available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=26AL-0137E

III. Cost Allocation Methodologies to Minimize Cost Shifting

Cost allocation refers to determining how a utility's revenue requirement is allocated among customer classes and individual customers. The objective is to assign costs in a manner that reasonably reflects cost causation while producing rates that are practical to administer.

A. Traditional Methods of Generation Cost Allocation

Historically, most generation costs have been pooled and allocated across all ratepayers using a variety of energy- and demand-based allocators intended to approximate cost causation. These methods tend to rely on relatively simple indicators, such as a customer class's contribution to one or more annual system peak hours, rather than explicitly identifying the investments attributable to individual customers or customer classes.

The unique characteristics of new large loads (including the scale of these loads and their high load factors) are prompting commissions to acknowledge that existing production allocation methodologies may fail to accurately reflect the costs caused by these customers. Active proceedings are underway to rethink traditional cost of service methods and evaluate options for directly assigning incremental generation costs to large load classes or individual customers.

The methods described below illustrate a variety of traditional production cost allocation methods before outlining the more recent trends in direct assignment approaches and applications.

1. **Coincident Peak (CP) Methods:** Coincident peak methods allocate generation costs based on each customer class's demand during one or more system peak hours. Common variants include the 1CP method (the single annual system peak), 4CP (one monthly peak during the summer season), and 12CP (one peak each month). For example, Public Service Company of New Mexico allocates generation and transmission costs using a 3S1WCP methodology based on the three highest summer peak hours and one winter peak hour.[13]

   Although CP methods are straightforward and widely used, they may under-allocate costs to large load customers. Customers with on-site generation or flexible operations may reduce demand during a limited number of anticipated system peak hours while continuing to require substantial generation capacity throughout the remainder of the year. For example, the 1CP method could allow large loads to avoid all demand-related costs if they run on backup

[13] Casas, Abraham. Direct Testimony on behalf of NM PRC in Case No. 22-00270-UT, p. 8. December 15, 2022. Available at: https://www.txnmenergy.com/~/media/Files/P/PNM-Resources/rates-and-filings/PNM%202024%20Rate%20Change%20Filing/17%20Direct%20Testimony%20of%20Abraham%20Casas%20-%20Cost%20Allocation.pdf.

generation during a relatively small number of predicted peak hours. Large load peak avoidance shifts costs to customers who do not have backup generation or load shifting technologies.[14]

CP methods also fail to accurately capture the costs imposed by data centers' continuous demand, which drives investment in baseload and intermediate capacity in addition to the peaking capacity that the CP methods emphasize. Thus, CP methods may allocate a relatively smaller proportion of generation costs than is actually incurred to serve these customers.[15]

2. **Average & Excess (A&E):** A&E allocates costs to a customer class based on class average energy usage and excess demand, where excess demand is measured as the difference between the class non-coincident peak demand (based on the customer class's own highest load at any time regardless of the system peak) and its average annual demand. The method can advantage customer classes that use a higher proportion of baseload compared to peaking resources.[16]

3. **Peak & Average (P&A):** P&A assigns the demand-related classification of fixed costs by dividing the system annual peak by the sum of annual peak and the average demand (CP/(CP + average demand)). Data requirements are minimal. P&A tends to assign more costs to customer classes with consistently high utilization than CP methods because their high energy usage inflates the "average" component. However, critics argue that the weighting of average and peak is arbitrary and does not accurately represent how costs are incurred or how generation is planned and operated.[17]

4. **Base/Intermediate/Peak (BIP):** Also known as a production stacking method, BIP assigns the dollar amount of investment by type of plant to recognize proper weighting of investment costs between inexpensive base load units relative to expensive peaker units. BIP requires a set of decisions about the definition of generation classes and the classification percentage for each class. Base load units and wind and solar facilities are classified and allocated based on their roles in meeting the utility's energy requirements, while peaker units are classified and allocated based on peak demand. Intermediate resources are classified and allocated based on their capacity factors. Where detailed hourly load data are available, customer class usage can be matched to the output of different resource types, resulting in a more refined allocation of generation costs than simpler peak-based methods.

5. **Probability of Dispatch (POD):** This method examines how each customer class utilizes each generation resource. The method evaluates each generation asset on an hourly basis, then assigns asset capital costs to individual hours based on how that individual plant is dispatched. The hourly capacity costs for each generating asset are summed to develop hourly investment

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[14] Watkins, Glenn, Direct Testimony on behalf of the Kentucky Office of the Attorney General, Case No. 2020-00350, p. 7. March 2021, available at: https://psc.ky.gov/pscecf/2020-00349/Lisa.Mendez/03092021013004/Watkins_KU__and_LGE_Testimony.pdf.

[15] Palmer, Caroline. Direct Testimony on behalf of MNSC, U-21859, p. 30. June 2025. Available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000u7ZjxAAE.

[16] Palmer, Caroline. Rebuttal Testimony on behalf of Sierra Club in Docket No. ET-2025-0184, p. 37.

[17] Overcast, H. Edwin. Rebuttal Testimony on behalf of The Empire District Electric Company in Case No. ER-2014-0351, p. 5.

cost responsibilities before being assigned to individual rate classes based on class contributions to system load by hour of the year. POD has been found to result in a fair allocation of embedded capacity costs as it uses hourly generator output data and 8,760 customer class load studies for accurate allocation. However, critics note that POD reflects how existing resources are currently operated rather than the planning decisions that originally drove those investments.[18]

B. Additional Approaches to Generation Cost Allocation for Large Load Customers

Below we describe cost allocation methods that are increasingly being used or considered to address the unique cost allocation issues posed by large load customers.

Direct Assignment

Unlike the cost allocation methodologies described above, direct assignment does not allocate all generation costs through a common cost pool. Instead, it assigns specific costs directly to the customer or customer class responsible for causing those costs. For example, street lighting facility costs have historically been assigned to the streetlighting class of customers without need for the demand- or energy-related classifications outlined above. For example, Michigan's Public Service Commission has ordered Consumers Energy, DTE Energy, and Indiana Michigan Power to model six cost allocation pathways in subsequent rate cases, two of which assign a portion of costs directly to large load classes and customers. The resulting rates across classes will then be compared across the scenarios.

Embedded vs. Incremental Cost-Based Methods for Generation

Most traditional embedded cost studies do not take differential growth of customer classes into account. An incremental study, on the other hand, looks at the system costs incurred over a relatively short time horizon to serve new large loads, recognizing these investments as driven by a specific class of customers. This approach may differ from "direct assignment" approaches in that it seeks to determine the portion of all incremental costs that are directly attributable to the customer.

Incremental cost analysis requires defining a counterfactual of the utility's cost structure *without* the customer or customer class in question. The incremental cost of serving a large load is then some fraction of a discrete plant addition triggered by their capacity and energy demands. However, there is not yet a consensus method for determining what fraction of a new plant is attributable to the new customer versus load growth that would have occurred anyway. There is also the question of determining what share of benefits from new generation facilities should be attributed to surrounding customers. Measuring beneficiary vs. cost-causer shares requires detailed modeling assumptions, introducing uncertainty and the potential to create precedent issues when applied to large load customers of different natures or in different jurisdictions.

[18] RAP, "Electric Cost Allocation for a New Era," p. 120. January 2020, available at: https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf. January 2020. Available at: https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

Methods for measuring incremental costs (i.e., isolating cost associated with large loads rather than pooling the resulting costs across customer classes) include variations of the following:

- Comparing pathway scenarios: Similar to a long-run incremental cost study, a utility can isolate the incremental cost of service by running a comprehensive capacity expansion model both with the new large load, and without it. As stated by an intervenor in the Consumers Energy large load tariff case, “One way to [minimize cost shifting] is for Consumers to model an optimal system expansion plan both with and without large load additions, which would clearly identify the incremental costs imposed by the large load customers. Those incremental costs could then be directly assigned to large load customers by designing the applicable tariff rate to collect the revenue requirement associated with such incremental costs. By doing so, the Company would be more directly following cost causation principles, while also avoiding the subjectiveness and imprecise nature of traditional cost of service studies.”[19]

- Avoided cost studies: A utility can identify the cost of the next marginal generation unit that would be needed to serve peak demand with the entrance of a new load as well as the variable cost of running these units at a higher utilization to serve baseload. An additional method is needed to reconcile the results of this study with the revenue requirement.[20]

The “And” Approach

A large customer that pays only for incremental costs avoids contributing to embedded system-wide costs, such as reliability benefits from the existing generation fleet, despite benefiting from them. To address this, regulators may establish rates using one costing approach for the existing load while using a separate way to set prices for incremental usage and allocating incremental resources to specific rate classes. This strategy serves to tax fast-growing classes with high growth costs while shielding slower-growing classes.[21]

The Regulatory Assistance Project’s (RAP’s) cost allocation manual provides additional guidance on addressing differentials between resulting incremental and embedded cost calculations:

> “Where incremental costs are much higher than embedded costs, the difference may be assigned to classes in proportion to their growth…higher costs may also be allocated to an entire class but collected through a rate element (e.g., consumption over twice the monthly average).”[22]

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[19] Initial Brief of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan; Case No. U-21859, August 21, 2025, p. 66. Available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000016WgQ6AAK.

[20] NARUC, “Module III: Guidelines on Determining the Process for Allocating Costs Among Customer Classes,” p. 41. July 2023, available at: https://pubs.naruc.org/pub/EAEB019A-9F87-8CF2-D6C9-E531092D0C85.

[21] *Id,* p. 14.

[22] RAP, “Electric Cost Allocation for a New Era,” January 2020, p. 174. Available at: https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

Costs of Accelerated Investment

The principle of accelerated investment recognizes that even where a large load customer does not immediately begin construction of new generating resources, its additional demand may accelerate the timing of future investments. Thus, large load customers should bear the costs of that acceleration (the time value of money).[23] Evergy Kansas addressed the increased cost to all customers of accelerated investment by proposing a System Support Rider to collect a portion of revenue requirement associated with a future generic investment and credit it to non-large load classes during a subsequent rate case.[24]

Bring Your Own Generation

While not a cost allocation method, several states are actively examining whether large loads should be required or incentivized to bring dedicated generation rather than relying only on shared generation resources. The Public Utility Commission of Texas recently approved ERCOT's Batch Zero Process for connecting large loads, which includes provisions allowing large loads to accelerate interconnection if they build their own on-site power generation.[25]

C. Summary of Generation Cost Allocation Approaches

The following table summarizes the primary allocation methods introduced above, including how they may apply to large loads.

	Mechanism	Description	Large Load Implications
Traditional Pooled	Coincident Peak	Based on system peak hours	Tends to favor large loads with high load factors; easy to game with backup generation during predicted system peaks. The larger the number of peak hours considered, the more that risk falls on other customers.
	Average & Excess	Contribution to Average = (Class Average Demand / System Average Demand)*System Load Factor	Favorable to large loads with high load factors due to less excess usage and higher baseload usage

[23] Palmer, Caroline. Direct Testimony on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan in Case No. U-21859, p. 31.

[24] Lutz, Bradley. Surrebuttal Testimony on behalf of Evergy Missouri, Case No.: EO-2025-0154, beginning p. 11.

[25] ERCOT, "ERCOT's New Batch Connection Process for Large Electricity Users." June, 2026, available at: https://www.ercot.com/files/docs/2026/06/18/ERCOT-Trending-Topic-New-Batch-Connection-Process-for-Large-Electricity-Users.pdf.

	Mechanism	Description	Large Load Implications
		Contribution to Excess = NCP – Average Demand	
	Peak & Average	Typically a 50/50 weighting of class CP ratio and class energy ratio. Base system costs allocated to all classes based on average demand (energy). Peak portion allocated to classes responsible for system peak demand (capacity).	Favorable to large loads with high load factors due to higher baseload usage that avoids large portion of peak (capacity) costs
	Base /Intermediate/ Peak	Base load units allocated based on role in energy requirements Intermediate units allocated based on capacity factors Peaker units allocated based on peak demands	Favorable to large loads with high load factors due to higher baseload usage that avoids large portion of peak (capacity) costs
	Probability of Dispatch	Assigns capital costs for plants based on dispatch across hourly profile (e.g., 8,760), then assigned to classes based on class hourly contributions to system load	
Segregated	Direct Assignment and Incremental Cost Methods	But-for pricing approach that attributes new generation sources directly to large load classes or customers	Best addresses cost causation of new large loads. However, large loads should also contribute to the embedded costs of the existing system, which these customers also use and benefit from. [26]

[26] NARUC, "Module III: Guidelines on Determining the Process for Allocating Costs Among Customer Classes." July 2023, p. 28. Available at: https://pubs.naruc.org/pub/EAEB019A-9F87-8CF2-D6C9-E531092D0C85.

D. Transmission Cost Allocation

When it comes to transmission cost allocation, Load Serving Entities (LSEs) with large load customers typically pay costs to transmission providers before recovering costs through retail rates.[27] Design choices across methodological dimensions directly shape whether existing ratepayers bear cost shifting risks created by large load customers. Some mechanism choices are binary (mutually exclusive), while others can be pursued as a hybrid approach according to state needs.

Local Transmission Allocation charges the LSE for lines within its specific footprint. Each transmission utility builds and owns its local facilities and bundles the costs into its own Open Access Transmission Tariff (OATT) "license plate," rather than pooling them regionally.

Regional Transmission Allocation spreads the costs of wide-area projects across multiple utility zones, proportional to the collective electricity demand and shared benefits. Both WestConnect and Southwest Power Pool (SPP) are bound to FERC-approved regional cost allocation principles; after the transmission revenue requirement is decided across states, a state commission makes cost-allocation decisions at the retail level. Regional transmission allocation methods include:[28]

- **Beneficiary-Pays:** Transmission costs can be allocated based on a granular assessment of which customers benefit from a given investment (beneficiary-pays principle). Compared to the Load-Ratio-Share method described below, this mechanism better captures cost causation by assigning costs more directly to the LSEs serving large loads but is more likely to generate disputes for the same reason.

- **Load-Ratio-Share (Postage Stamp):** The load ratio share is a customer's or zone's proportion of total system load. Load ratio share is administratively simpler than beneficiary-pays but uniformly spreads costs agnostic of who may be driving the need for new infrastructure. This can mute price signals for large loads while protecting large loads from cost spikes related to new projects triggered by the transmission constraints they impose.

Embedded vs. Incremental Cost-Based Pricing for Transmission

Embedded cost allocation approaches allocate the average cost of a function (e.g., transmission) to customers based on a cost allocation methodology (e.g., contribution to the system's coincident peak). An incremental cost-based allocation approach assigns costs directly to a customer or group that caused the cost to be incurred. The latter method is very similar to the "but-for" cost causation approach described below, but is used in the context of expanding the broader transmission grid more often than a localized, standalone addition.

[27] For bundled retail sales, states regulate transmission cost allocation directly.

[28] Grid Strategies, Federal Transmission Pricing Vol. 1. P. 27. May 2026, available at: https://gridstrategiesllc.com/wp-content/uploads/GS_Federal-Transmission-Pricing-Vol-1.pdf

- **But-For Causation:** This method asks whether a network upgrade would have taken place if a specific new load (or generator) had never connected. If the new load is deemed to have triggered the upgrade, it must pay 100% of the cost for the upgrade.[29]

There is an ongoing debate as to whether (and how) embedded and incremental cost-based pricing can be combined to simultaneously capture a new large load's incremental cost to the system and benefits gained from the existing system. Under the practice of Participant Funding, RTOs can directly assign network upgrade costs to interconnecting generators in addition to embedded cost rates. However, FERC Order 1000 (2011) disallows Participant Funding as a cost allocation method for regional pricing.[30]

FERC's 1994 Transmission Pricing Policy statement prohibits transmission providers from charging both embedded costs and incremental costs of the same transmission service on the same system, reasoning that such an approach could overcharge competing generators for access to the transmission network. Exceptions allowing for a nuanced approach include accounting for costs on a disaggregated basis by facility, so transmission providers charge for some lines using embedded costs and others using incremental costs.[31] Another form of **"and pricing"** is to mix embedded and incremental costs based on a threshold (e.g., assigning 25% of costs to incremental-based pricing and the other 75% to embedded). Dynamic "and pricing" would switch between incremental and embedded rates depending on which is higher, similar to a static **"higher of"** pricing approach.[32]

FirstEnergy has proposed that data center customers pay two rate components—their share of the existing zonal transmission rate *and* an expansion rate for the costs of network upgrades needed to interconnect their facilities to the grid.[33] The expansion rate could be reallocated annually as new customers interconnect to the same transmission facilities. FirstEnergy claims they avoid FERC's prohibition on "and pricing" by having each customer pay its pro-rata share of zonal transmission rate, with only the data center driving the expansion paying the additional expansion rate. FERC's show cause orders issued to all six of the ISOs/RTOs under its jurisdiction on June 18, 2026, mark the next step in finalizing the pricing reform for transmission cost transparency, and understanding which pricing methods can be employed to avoid cost shifting.[34]

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[29] To date, there does not appear to be a documented example of "but-for" causation principles applied to the second order, i.e., assigning costs directly to a new large load that does not trigger an immediate transmission upgrade but accelerates a planned one. FERC's show cause orders to each RTO/ISO issued June 18 with a 60-day response deadline may prompt RTOs/ISOs to address acceleration cost treatments.

[30] FERC Order No. 1000 – Transmission Planning and Cost Allocation. Page last updated November 2021. Available at: https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation.

[31] Grid Strategies. Federal Transmission Pricing, Volume 1. May 2026, p. 42. Available at: https://gridstrategiesllc.com/wp-content/uploads/GS_Federal-Transmission-Pricing-Vol-1.pdf.

[32] Grid Strategies. Federal Transmission Pricing, Volume 2. June 2026, p. 35. Available at: https://gridstrategiesllc.com/wp-content/uploads/Federal-Transmission-Pricing-Vol-2_Report_FINAL.pdf.

[33] Howland, Ethan. "FirstEnergy asks FERC to require data centers to pay for transmission interconnection costs." Utility Dive. June 9, 2026. Available at: https://www.utilitydive.com/news/firstenergy-ferc-data-center-transmission-interconnection/822333/.

[34] FERC. Fact Sheet: "FERC Takes Action to Supercharge America's Grid for Efficiency, Reliability, and a Bold Energy Future." June 18, 2026. Available at: https://www.ferc.gov/news-events/news/fact-sheet-ferc-takes-action-supercharge-americas-grid-efficiency-reliability-and.

Timing of Cost Recovery: Whether transmission costs are recovered up front (e.g., via deposits or funding requirements), over time through a tariff-defined crediting or reimbursement, or only after a triggering event such as a minimum-bill shortfall (as determined in a Financial Security Commitment) determines how the risks associated with load departures or delays is shared among customers. The Contract Term and Contributions in aid of construction mechanisms outlined earlier in this memo can shift financing-cost risk away from ratepayers but only if the underlying project is reasonably likely to proceed.

Treatment of Co-Located Generation: Large loads partially served by on-site generation present a choice between a gross energy-usage approach, which can over-account for co-located load and unfairly shift costs onto co-located load, or a net-load approach (reflecting the reduction in transmission withdrawals from on-site generation) which risks under-accounting for the load's reliance on the transmission system and can unfairly shift costs onto the other customers.[35] For example, PJM has historically permitted behind-the-meter generation to "net" against a customer's load to reduce Network Integration Transmission Service charges, but this rule is undergoing changes as FERC has ruled it as "no longer just and reasonable" because it allows large load customers to shift costs inappropriately to other transmission customers. Best practice likely requires a hybrid allocation factor that credits net withdrawals for energy purposes while still assessing a reliability or standby-service charge based on a measure closer to gross capacity.

Pairing any form of cost allocation mechanisms with the customer protection mechanisms mentioned in the earlier section (e.g., long-term service commitments, minimum demand charges, exit fees) can support the formation of contracts with clearly defined ratepayer safeguards. Cost allocation mechanisms can also directly include ratepayer protections. For example, LSEs (on behalf of large loads) can voluntarily pay to offset the cost of regional projects that do not meet the benefit-cost threshold in exchange for service benefits such as expedited processing or incremental withdrawal capability.[36] Pairing this voluntary payment with a binding recovery commitment would protect ratepayers from subsidizing projects that fail the benefit-cost test for the broader system while still allowing loads to obtain faster service.

E. Summary of Transmission Cost Allocation Considerations

	Mechanism	Description	Best Practice	Example(s)
Regional Allocation	Beneficiary-Pays	Granularly allocates costs based on quantified benefits to specific beneficiaries	Report large load-driven costs as a distinct bucket in rate informational filings	FERC Order 1000 regional cost allocation framework requires costs allocated in proportion to estimated

[35] Meyer, Sophie et al. *Federal Transmission Pricing, Volume 2*. Grid Strategies. June 2026. https://gridstrategiesllc.com/project/federal-transmission-pricing/.

[36] Meyer, Sophie et al. *Federal Transmission Pricing, Volume 2*. Grid Strategies. June 2026. https://gridstrategiesllc.com/project/federal-transmission-pricing/.

	Mechanism	Description	Best Practice	Example(s)
			on a project-specific basis	benefits with BCA ratio floor of 1.25[37]
	Load-Ratio-Share	Assesses costs based on a customer's load in proportion to total system load	Use one or a blend of allocators: coincident peak-based, energy usage-based, or incremental load growth-based	CAISO allocates 200kV+ regional revenue requirements on a uniform load ratio share basis across the system[38]
Pricing	Embedded Cost-Based	Assigns costs based on portion of utility's full cost of service (traditional revenue requirement approach)	**"Higher-Of" Pricing:** Charge LSE the higher of embedded and incremental cost rate **Disaggregated "And" Pricing:** Charge a blend of embedded and incremental rates, set by a threshold (e.g., embedded rate applies once incremental costs exceed $10M)	Xcel's 2023 Phase II Electric Rate Case allocated approximately $265 million of transmission-related costs across all customer classes based on the Four Coincident Peak methodology, with all customer classes receiving the same average cost allocation of $43/kW of respective contribution to the coincident peak.[39]
	Incremental Cost-Based	Marginal cost incurred to the system due to specific load entry; assigning cost causation requires robust power		FirstEnergy's proposal for data centers to pay an "expansion rate" covering the network upgrades needed to interconnect their facilities[40]

[37] Federal Energy Regulatory Commission Order No. 1000, issued July 21, 2011. Available at: https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation.

[38] CAISO Electronic Tariff 26 (Transmission Rates and Charges) (0.0.0), App. F, Sched. 3 (Regional Access Charge and Wheeling Access Charge) (30.0.0). May 1, 2026. Available at: https://www.caiso.com/documents/section-26-transmission-rates-and-charges-as-of-may-1-2026.pdf.

[39] Xcel Energy, Proceeding No. 23AL-0243E, Adopted February 7, 2024. Decision available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/2023-CO-Phase-II-Electric-Rate-Review-Decision.pdf.

[40] FirstEnergy Service Company, Supplemental Comments on Docket No, RM26-4-000, issued June 5, 2026, available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20260605-5169.

	Mechanism	Description	Best Practice	Example(s)
		flow and cost support documentation		
Timing	Up-front	Deposits or funding requirements for interconnection study costs, network upgrades, and/or regional transmission costs	Calibrate commitments to large-load risk profile by tying to objective risk criteria	Georgia's January 2025 PSC rule that data centers using >100MW must pay for upstream generation, transmission, and distribution costs as construction progresses[41]
	Over time	Tariff-defined crediting or reimbursement mechanism	Set ballon payment to LSE of remaining unreimbursed expenses after a set number of years (e.g., 20); ensure LSE-to-large-load pass-through terms are enforceable	Dominion's GS-5 includes a four-year ramp-up period during which billing demand is based on a contracted demand schedule rather than full installed capacity[42]
Co-Location	Gross Energy Usage	Look at total load without discounting for on-site generation to make allocation decision	Use a hybrid allocation factor that credits net withdrawals for energy purposes while still assessing a reliability or standby service charge based on gross capacity	CAISO assesses Transmission Access Charges on the Gross Load of each utility[43]
	Net Energy Usage	Only count the portion of co-located load not served by on-site generation to		PJM's tariff exempts load served by "Behind The Meter Generation" from transmission charges, but

[41] Georgia Public Service Commission. News Release: PSC Approves Rule to Allow New Power Usage Terms for Data Centers. January 23, 2025. Available at: https://psc.ga.gov/site/assets/files/8617/media_advisory_data_centers_rule_1-23-2025.pdf.

[42] Commonwealth of Virginia State Corporation Commission, Final Order for Application of Virginia Electric and Power Company, issued November 5, 2025, available at: https://www.scc.virginia.gov/docketsearch/DOCS/89g601!.PDF.

[43] CAISO Electronic Tariff 26 (Transmission Rates and Charges) (0.0.0), App. F, Sched. 3 (Regional Access Charge and Wheeling Access Charge) (30.0.0). May 1, 2026. Available at: https://www.caiso.com/documents/section-26-transmission-rates-and-charges-as-of-may-1-2026.pdf.

	Mechanism	Description	Best Practice	Example(s)
		make allocation decision		FERC has ordered changes to this to protect ratepayers[44]

[44] FERC. Order on Show Cause Proceeding, Directing Compliance Filings, Establishing Paper Hearing, And Granting in Part and Denying in Part Complaint. EL25-49-000. December 18, 2025. Available at: https://www.ferc.gov/media/e-1-el25-49-000-0.

Continue Your Research

This guide provides a practical overview of large load tariffs and best practices. For readers seeking additional context and technical depth, the following companion publication is available on our website:

- **Large Load Policy & Technical Analysis Survey** — A comprehensive examination of the regulatory landscape, implementation considerations, current solutions and trends relevant to large loads.

Appendix: Sample Large Load Tariffs

Contents

	State	Utility	Tariff
1.	CO	Public Service Company of Colorado (Xcel Energy)	Transmission Large Service Tariff (proposed); Clean Transition Tariff (proposed)
2.	IN	Indiana Michigan Power Company	Industrial Power Tariff
3.	KY	Kentucky Power Company	Industrial General Service Tariff
4.	MI	Consumers Energy Company	Large General Service Primary Demand Rate GPD Tariff
5.	OH	Ohio Power Company (AEP Ohio)	Data Center Tariff
6.	VA	Virginia Electric and Power Company (Dominion)	Schedule GS-5 High Load/Load Factor Service; Terms and Conditions
7.	WI	Northern States Power Company Wisconsin	Very Large General Time-of-Day Service (proposed)
8.	WV	Appalachian Power Company	Large Capacity Power Service Tariff

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PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 73

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ELECTRIC RATES	RATE	
TRANSMISSION LARGE SERVICE		N

SCHEDULE TL N

APPLICABILITY N

Applicable to electric power service supplied at Transmission Voltage to Commercial and Industrial Customers whose reasonably forecast new Demands are 50 MW or greater and who begin taking service on or after May 3, 2026 or whose reasonably forecast new incremental (expanded) Demands are 50 MW or more on or after May 3, 2026. Applicable to Supplemental Service. Not applicable to Standby or Resale Service. N

AVAILABILITY N

As set forth in the General Definition Section of the Electric Tariff, Customers taking Service under this Schedule and under Schedule Net Metering (Schedule NM), will not be subject to the requirements of Supplemental Service. N

MONTHLY RATE N

Service and Facility Charge, per service meter: REF. NO. N
[TBD]…….. .... TBD $ N

(Continued on Sheet No. 73A) N

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ELECTRIC RATES | RATE

TRANSMISSION LARGE SERVICE N

SCHEDULE TL N

MONTHLY RATE – Cont'd N

Demand Charge: N
All Kilowatts of Billing Demand, per kW N

Generation and Transmission Demand - Summer Season	$ 17.37	N
Generation and Transmission Demand – Winter Season	10.42	N

Energy Charge: N

All Kilowatt-Hours used, per kWh...	0.00154	N

The Summer Season shall be from June 1 through September 30. The Winter Season shall be from October 1 through May 31. N N

MINIMUM MONTHLY BILL N

Any applicable Service and Facility Charge shown above plus the Demand Charge, plus the Production Meter Charge if applicable. For Customers receiving Supplemental Service, the Minimum Monthly Bill shall also include the Production Meter Charge. The Minimum Monthly Bill includes all applicable rate adjustments calculated based on customer's Billing Demand, including the Electric Commodity Adjustment (ECA) Schedule TL Minimum Demand Charge. N N N N N N N

OPTIONAL SERVICE N

Except for Customers receiving Supplemental Service, Customers receiving service under this rate may elect to receive interruptible service under the Interruptible Service Option Credit (ISOC). Customers may also participate in the Clean Transition Tariff (CTT). N N N N

ADJUSTMENTS N

This rate schedule is subject to all applicable Electric Rate Adjustments as on file and in effect in this Electric Tariff. N N

PAYMENT AND LATE PAYMENT CHARGE N

Bills for electric service are due and payable within thirty (30) business days from the date of invoice. A business day for purposes under this Payment and Late Payment Charge section is all non-Holiday weekdays. Any amounts in excess of fifty dollars ($50.00) not paid on or before three (3) business days after the due date of the bill shall be subject to a late payment charge of one and one half percent (1.5%) per Month. N N N N N N N

(Continued on Sheet No. 73B) N

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ELECTRIC RATES | RATE

TRANSMISSION LARGE SERVICE N

SCHEDULE TL N

DETERMINATION OF BILLING DEMAND N

Billing Demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated Measured Demand used during the Month, except as set forth in the Company's Commercial and Industrial Rules and Regulations. N

Billing Demand for the Generation and Transmission Demand Charge shall be the greater of: Measured Demand used during the Month, or eighty percent (80%) of the customer's Contract Capacity, as specified in the Customer's Electric Service Agreement. N

SERVICE PERIOD N

All service under this schedule shall be for a minimum period of fifteen (15) consecutive Years, and the term will be automatically extended for successive five (5)-year periods until terminated. Customer may terminate service for any reason upon twenty-four (24) months' written notice to the Company and payment of an Exit Fee. N

PRODUCTION METER INSTALLATION N

The Company shall install, own, operate, and maintain, the metering to measure the electric power and energy supplied by the Customer's generation to allow for proper billing of the Customer under this schedule. For Supplemental Service, the Customer shall pay the Monthly Production Meter Charge under this schedule. For Customers who are net metered, the applicability of the Production Meter Charge can be found under the Net Metering Service Schedule. N

PURCHASE OF CUSTOMER'S EXCESS ENERGY N

If a Customer receiving Supplemental Service produces energy exceeding the energy used by the Customer's facility during any Monthly billing period, the energy shall be purchased by the Company either under a Power Purchase Agreement between the Company and the Customer, or at the Energy Charge under this schedule. N

(Continued on Sheet No. 73C) N

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ELECTRIC RATES | RATE

TRANSMISSION LARGE SERVICE

SCHEDULE TL

RULES AND REGULATIONS

Service supplied under this schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with the Commission, and to the terms and conditions of any special contract, including an Electric Services Agreement or Interconnection Agreement, for service between Company and Customer not in conflict herewith, and subject to the following conditions unless otherwise approved as part of an agreement between the Company and the Customer submitted to and approved by the Commission:

1. Customers with generation resources connected in parallel with the Company's electric system are subject to the Character of Service for Secondary, Primary and Transmission Standby Service section of the Company's Rules and Regulations for Commercial and Industrial Service.

2. Customer shall enter into an Electric Service Agreement with the Company that will include additional detail on the commercial terms of service under this Schedule TL. The Electric Service Agreement shall include the Customer's Contract Capacity for the term of the Electric Service Agreement, including for each month of any Load Ramp and the Maximum Contract Capacity. Customer shall also enter into an Interconnection Agreement with the Company that specifies the terms under which the Company will design, engineer, procure, permit, construct, own, operate, and maintain any facilities necessary to allow Customer to interconnect to receive electric service from the Company.

3. Customer's service shall be limited to the Contract Capacity specified in the Electric Service Agreement except as otherwise specified therein. Requests to increase the Contract Capacity are subject to the availability of generation and transmission capacity determined at the sole discretion of the Company. Requests to decrease Contract Capacity require twenty-four (24) months' written notice to the Company and payment of the Contract Capacity Reduction Payment equal to, in addition to any revenue or other fees that may be due and owing by Customer, (i) the difference between (a) the Minimum Monthly Bill prior to the Contract Capacity Reduction, and (b) the Minimum Monthly Bill after the Contract Capacity Reduction, multiplied by (ii) the number of months remaining in the term after the effective date of the Contract Capacity Reduction.

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RATE

TRANSMISSION LARGE SERVICE N

SCHEDULE TL N

RULES AND REGULATIONS – Cont'd N

4. Customer shall provide the Company with an estimated, non-binding, and confidential Load Forecast consisting of five (5) years of expected monthly on-peak and off-peak demand and energy for the Customer Site. Each Load Forecast shall be a good-faith, commercially reasonable estimate and inaccuracies in the Load Forecast shall not constitute an event of default under or be considered a breach of the Electric Service Agreement. Customer shall provide an updated Load Forecast no later than January 1st and June 1st of each year of the term of the Electric Service Agreement, and as otherwise requested by the Company. Customer shall exercise commercially reasonable efforts to notify Company of any planned load reductions or increases at the Customer's Site. N

5. In the event that the Electric Service Agreement is voluntarily terminated by Customer or terminated by the Company due to an uncured material breach by the Customer, the Customer shall pay the Company an Exit Fee. The Exit Fee shall include any revenue or other fees that may be due and owing by Customer as of the Termination Date plus the sum of all Minimum Monthly Bills for each of the remaining months of the term of the Electric Service Agreement calculated using the Contract Capacity for the applicable month set forth in the Electric Service Agreement. In the event that the Termination Date falls prior to energization pursuant to the terms of the Interconnection Agreement, the remaining number of months for calculation of the Exit Fee shall be the total number of months in the Initial Term of the Electric Service Agreement. In the event of a voluntary termination by Customer, the Exit Fee shall be due twenty-four (24) months after the date the customer provides notice of termination, and in the event of a termination by the Company for a material breach by the Customer the Exit Fee shall be due within thirty (30) days of the Termination Date. The Company and the Customer will use commercially reasonable efforts to mitigate all costs, damages, and charges arising out of termination of the Electric Service Agreement. N

6. Customers shall provide credit support at their sole cost and expense in favor of Company and shall maintain such credit support during the term of the Electric Service Agreement. N
   a. Except as otherwise specified in this Schedule TL, all credit support shall be delivered within fifteen (15) business days following execution of an Electric Service Agreement. N

(Continued on Sheet No. 73E) N

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TRANSMISSION LARGE SERVICE N

SCHEDULE TL N

RULES AND REGULATIONS – Cont'd N

b. Customer shall deliver a Guaranty to the Company in a mutually agreeable form issued from a guarantor that is (a) a United States domiciled entity; and (b) either has (i) no Credit Rating but whose tangible net worth is more than five hundred million dollars ($500,000,000), or (ii) has a Credit Rating equal to or better than BBB- from S&P or Baa3 from Moody's ("Guarantor"). In no event shall the Guarantor's liability exceed the sum of all Minimum Monthly Bills for each of the remaining months of the term of the Electric Service Agreement calculated using the Contract Capacity for the applicable month set forth in the Electric Service Agreement (the "Guaranty Cap"). Prior to energization pursuant to the terms of the Interconnection Agreement the remaining number of months of the term shall be the total number of months in the Initial Term. N

c. A customer that provides credit support through a Guaranty must provide additional credit support in the form of (i) a cash deposit held in an escrow account and under terms and conditions as mutually agreed to by the Customer and the Company and with interest accruing for the benefit of Customer, or (ii) an irrevocable standby letter(s) of credit. The amount of the additional credit support shall be equal to the Minimum Monthly Bill at the Maximum Contract Capacity as specified in the Electric Service Agreement multiplied by six (6), and shall be delivered to the Company at least thirty (30) days prior to the start of the Load Ramp. Customer shall maintain the additional credit support throughout the term of the Electric Service Agreement. N

d. A Customer that is unable to provide a Guaranty shall deliver to the Company credit support equal to the Minimum Monthly Bill at the Maximum Contract Capacity as specified in the Electric Service Agreement multiplied by sixty (60). Such credit support shall be in the form of (i) a cash deposit held in an escrow account and under terms and conditions as mutually agreed to by the Customer and the Company and with interest accruing for the benefit of Customer, or (ii) an irrevocable standby letter(s) of credit. N

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TRANSMISSION LARGE SERVICE N

SCHEDULE TL N

RULES AND REGULATIONS – Cont'd N

e. Any credit support provided as a letter of credit under this Schedule TL shall be issued by a U.S. bank or other financial institution that is acceptable to Company with a minimum rating of A- with Standard & Poor's and A3 with Moody's (unenhanced by third-party support). If there are split ratings amongst rating agencies, the Company will use the lowest of different ratings within the same rating agency and amongst different rating agencies. A letter of credit must have an acceptable minimum rating of A-/A3 on its own by at least one of the rating agencies. If such rating is equivalent to A-/A3, the issuer must not be on credit watch or have a negative outlook by any rating agency. The ratings are defined as follows (if available): long term issuer rating, long term senior unsecured rating, or long-term counterparty risk assessment/rating (for Moody's) N

f. Upon the occurrence and during the continuance of a Credit Event, within thirty (30) days of demand from Company to Customer, Customer shall provide to Company either (a) a cash deposit, (b) letter of credit, or (c) other credit support in a form and from an entity reasonably acceptable to Company, in the amount of Company's credit exposure over the remaining Term of the Electric Service Agreement, which credit support shall not exceed the Guaranty Cap. A "Credit Event" means one or more of the following: (i) that neither Customer nor Guarantor has a Credit Rating and the Guarantor's Tangible Net Worth is less than five hundred million dollars ($500,000,000); (ii) the Guarantor has a Credit Rating and such Credit Rating is not equal to or better than BBB- from S&P or Baa3 from Moody's, and Customer does not have a Credit Rating equal to or better than BBB- from S&P or Baa3 from Moody's; (iii) Guarantor has declared bankruptcy or has otherwise become insolvent; or (iv) a Guarantor default. N

7. No Electric Service Agreement under this Schedule TL shall be assigned transferred without the written consent of the Company, and any assignee or transferee must meet the credit metrics required by the Company. N

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ELECTRIC RATES | RATE

CLEAN TRANSITION TARIFF

SCHEDULE CTT

APPLICABILITY

Applicable as an optional service for Customers taking service under the Company's Transmission Large Service rate (Schedule TL) to support the acquisition of eligible, carbon-free generation resources.

AVAILABILITY

This Schedule is available to Customers taking service under Schedule TL who have signed, or contemporaneously sign, an Electric Service Agreement and an Interconnection Agreement.

A Customer may participate in Schedule CTT to support the development of CTT Resources within the Company's service territory. CTT Resources will be identified by the Customer and may include, but are not limited to, resources identified through the Company's resource planning process and that are not otherwise selected for development or procurement, or projects that provide emerging technology and innovation benefits, but which would not otherwise be selected through the Company's least-cost procurement process. Customers may request assistance from the Company in identifying eligible CTT Resources.

A Customer proposing a project under this Schedule must assume financial responsibility for the CTT Resource and project costs shall be covered by the Customer in one or more commercial agreements between the Customer and the Company. The Company retains full discretion to evaluate a project for feasibility and reasonableness, and to fully negotiate the ownership and commercial structure surrounding the project. Regardless of the commercial structure surrounding the CTT Resource, the Company shall remain the Customer's retail electric service provider.

One or more Customers may agree to jointly support one or more CTT Resources pursuant to this Schedule.

(Continued on Sheet No. 108A)

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ELECTRIC RATES | RATE

CLEAN TRANSITION TARIFF N

SCHEDULE CTT N

DEFINITIONS N

Accredited Capacity N
As defined in one or more commercial agreements between the Company and the Customer. N N

CTT Resource N
A generation resource using emerging carbon free electric generation technologies or long duration storage technologies that enable operation of a carbon-free system. Examples of eligible technologies include, but are not limited to, geothermal, hydroelectric, hydrokinetic, nuclear, renewably sourced hydrogen, long duration storage, and electrical energy from fossil resources with active capture and storage of carbon dioxide emissions that meet Environmental Protection Agency requirements. The following technologies are ineligible for consideration under Schedule CTT: commercially mature wind, solar, short duration storage, and any technology that directly emits carbon dioxide while producing electricity. N N N N N N N N N N N N N

Company-Owned CTT Resource N
A CTT Resource selected by the Customer and developed or purchased by the Company. N N

Excess Capacity N
Where Accredited Capacity from the CTT Resource exceeds Customer demand, adjusted for the planning reserve margin. N N

Excess Energy N
Energy produced by a CTT Resource during any given hour that exceeds the Customer's energy use during that hour. N N

Power Purchase Agreement (PPA) N
A long-term electricity supply agreement between a power producer and the Company. N N

PPA CTT Resource N
A CTT Resource selected by the Customer and procured by the Company through a PPA. N N

(Continued on Sheet No. 108B) N

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ELECTRIC RATES | RATE

CLEAN TRANSITION TARIFF

SCHEDULE CTT

CALCULATION OF THE CLEAN TRANSITION TARIFF CREDIT

A Customer participating in Schedule CTT will receive a CTT Credit on its bill. The value of the credit shall vary based on whether the Customer has matching energy or capacity between its load and the CTT Resource.

When the CTT Resource's Accredited Capacity is less than or equal to the Customer's monthly billed demand, the CTT Credit shall be equal to the Accredited Capacity multiplied by (i) the generation capacity charges embedded in the Schedule TL demand charge, (ii) the Purchased Capacity Cost Adjustment (PCCA), and (iii) the Clean Energy Plan Rider (CEPR). No CTT Credit will be given for Excess Capacity, or when the CTT Resource Accredited Capacity exceeds the Customer's monthly billed demand.

Energy matching will be determined on an hourly basis by comparing the CTT Resource's and Customer's energy usage in kWh. For matching energy, the CTT Credit for energy will be equal to the CTT Resource's energy output multiplied by: (i) the Schedule TL energy charge, and (ii) the Electric Commodity Adjustment (ECA) . For any Excess Energy, the CTT Credit will be based on the marginal cost of energy as determined by the Company's Cost Calculator software.

Further details on the calculation of the CTT Credit will be specified in one or more commercial agreements between the Customer and the Company concerning participation in Schedule CTT.

DETERMINATION OF THE CLEAN TRANSITION TARIFF CHARGE

All incremental costs associated with the CTT Resource will be assigned to the Customer or Customers in the form of the CTT Charge through one or more commercial agreements between the Customer(s) and the Company for the CTT Resource. Non-participating Customers may not bear incremental costs associated with the CTT Resource. For a Company-Owned CTT Resource, the CTT Charge will be the annual revenue requirement of that resource. For a PPA CTT Resource, the CTT Charge will be equal to the full costs of the PPA. The Customer's CTT Charge will include any program administration costs not covered by Schedule TL. Other costs may be included in the CTT Charge where necessary to insulate non-participating Customers from bearing incremental costs associated with the CTT Resource.

(Continued on Sheet No. 108C)

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ADVICE LETTER NUMBER

ISSUE DATE

DECISION/ PROCEEDING NUMBER

REGIONAL VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE

COLO. PUC No. 8 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 108C

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No.

ELECTRIC RATES | RATE

CLEAN TRANSITION TARIFF

SCHEDULE CTT

DETERMINATION OF THE CLEAN TRANSITION TARIFF CHARGE - Cont'd

The CTT Charge will be based on the specific characteristics of the CTT Resource identified by the Customer and agreed to by the Company. The amount of the CTT Charge will be specified in one or more commercial agreements between the Customer and the Company.

CLEAN TRANSITION TARIFF CREDIT AND CHARGE BILLING
A Customer participating in Schedule CTT will have project-specific charges and credits on its bill reflecting the CTT Charge and CTT Credit agreed to in one or more commercial agreements between the Customer and the Company. The Customer's bill will include the standard rate under Schedule TL (inclusive of all applicable riders) plus the CTT Charge, and minus the CTT Credit.

PROGRAM PRINCIPLES
Service supplied under this Schedule is subject to the terms and conditions set forth in the Company's Rules and Regulations on file with the Commission and the following conditions:

1. Should there be any conflict between the provisions within this Schedule and the applicable service tariff, the provisions herein will control. Service provided under this rate schedule is subject to the terms and conditions set forth in the Electric Service Agreement and Interconnection Agreement between the Customer and the Company under Schedule LT, and any other commercial agreements between the Customer and the Company necessary to effectuate this Schedule.

2. Commercial agreements between the Company and the Customer for participation in this Schedule CTT shall include (i) contract terms aligned with the CTT Resource contract term or asset life, (ii) the ability for subscriptions to transfer to another eligible Customer, (iii) pathways for the Company to identify and replace Customer if the Customer participates in Schedule CTT and exits early, and (iv) an exit fee payment obligation if no replacement for the Customer is reasonably secured. Additional terms may be included to the extent necessary to ensure that Customer assumes full financial responsibility for costs associated with the CTT Resource and to mitigate the risk of any costs being incurred by non-participating Customers.

(Continued on Sheet No. 108D)

ADVICE LETTER NUMBER

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DECISION/ PROCEEDING NUMBER

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

EFFECTIVE DATE

COLO. PUC No. 8 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 108D

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No.

ELECTRIC RATES

RATE

CLEAN TRANSITION TARIFF N

SCHEDULE CTT N

PROGRAM PRINCIPLES - Cont'd N

3. The Company will retain the environmental attributes associated with the CTT Resource for the benefit of all Customers, including Renewable Energy Credits (RECs). Customers who wish to retain environmental attributes associated with a CTT Resource may negotiate the transfer of such attributes through a separate commercial agreement between the Company and Customer. N N N N N N

ADVICE LETTER NUMBER

ISSUE DATE

DECISION/ PROCEEDING NUMBER

REGIONAL VICE PRESIDENT, Rates & Regulatory Affairs

EFFECTIVE DATE

TARIFF I.P.
(Industrial Power)

Availability of Service.

Available for general service customers. Customer's monthly billing demands under this tariff shall not be less than 600 kW. The customer shall contract for a sufficient capacity to meet normal maximum requirements with written contracts being required for capacity levels of 1,500 kW and greater.

Rate.

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 410 kWh per kW (¢/kWh)	Over 410 kWh per kW (¢/kWh)	Monthly Service Charge ($)
327	Secondary	16.474	5.703	1.359	180.00
322	Primary	14.089	5.413	1.313	275.00
323	Subtransmission	10.825	5.333	1.296	275.00
324	Transmission	10.194	5.058	1.286	275.00

Reactive Demand Charge / Credit

Reactive demand charge for each kVAr of leading or lagging reactive demand in excess of 50% of the kW metered demand will be charged at $1.50 / kVAr.

Reactive demand charge for each kVAr of leading or lagging reactive demand less than 50% of the kW metered demand will be credited at $1.50 / kVAr.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the sum of the Monthly Service Charge, the product of the Minimum Demand Charge and the monthly billing demand, and all applicable riders.

The Minimum Demand Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Minimum Demand Charge ($/kW)
327	Secondary	20.995
322	Primary	18.472
323	Subtransmission	15.106
324	Transmission	14.700

(Cont'd on Sheet No. 21.1)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Monthly Billing Demand.

The billing demands in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the off-peak hour provision, but the monthly demand so established shall in no event be less than 60 percent of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months or (c) 1,000 kW. The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

Off-Peak Hour Provision.

Demand created during the off-peak hours (as set forth below) shall be disregarded for billing purposes provided that the billing demand shall not be less than 60 percent of the maximum demand created during the billing month nor less than 60 percent of either (a) the contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

(Cont'd on Sheet No. 21.2)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.1)

Adjustments to Rate.

Bills computed under the rates set forth herein will be adjusted as follows:

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, the metered kWh, kVAr values will be adjusted for billing purposes. If the Company elects to adjust kWh, kW and kVAr based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Terms of Contract.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least one year's written notice to the other of the intention to discontinue service under the terms of this tariff. Where new facilities are required, the Company reserves the right to require initial contracts for periods of greater than two years.

A new initial contract period will not be required for existing customers who increase their contract requirements after the original initial period unless new or additional facilities are required.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

(Cont'd to Sheet No. 21.3)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.2)

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to customers having other sources of energy supply who purchase standby or backup service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW which the Company might be required to furnish, but not less than 1,000 kW. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

Terms and Conditions for Customer at or Over 70 MW Individually or 150 MW in the Aggregate.

Applicability.

These provisions apply to customers whose contract capacity is greater than or equal to 70 MW or is reasonably expected to grow to exceed 70 MW at an individual plant, or 150 MW or reasonably expected to grow to exceed 150 MW at one or more aggregated premises, each of 1 MW or larger ("Large Load Customer"). The Company will exercise reasonable discretion when choosing to aggregate premises, with such discretion based on factors including, but not limited to, premises sharing one or more of the following: common owner(s), a common parent company, common local electrical infrastructure, and common control. Large Load Customer's Initial Contract Term, load ramp, Load Ramp Period, contract capacity, and other terms of service under this Tariff will be defined in the Electric Services Agreement(s) ("ESA(s)"), executed between Company and Large Load Customer. These terms shall only apply to new load, or an expansion of existing load, occurring on or after January 1, 2024.

Contract Term.

The Large Load Customer's Initial Contract Term will be made for a period of not less than 12 years. A Large Load Customer may designate a Load Ramp Period, which can be no greater than five (5) years. If a Load Ramp Period is designated by the Large Load Customer, the Initial Contract Term shall commence after the Load Ramp Period ends. The Load Ramp Period is the later period of time from when: (a) electric service is available to the Large Load Customer or (b) the Large Load Customer is scheduled to begin taking electric service, until the time the Large Load Customer's maximum contract capacity is billed. The Contract Term is the Load Ramp Period plus the Initial Contract Term, and shall remain in effect thereafter unless cancelled or modified pursuant to the terms hereunder. Either party shall give at least 42 months written notice to the other of the intention to discontinue service under the terms of this tariff. Such notice shall not reduce the Contract Term except as provided for in the Exit Fee provision below.

(Cont'd to Sheet No. 21.4)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.3)

Contract Capacity Reductions.

Large Load Customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five (5) years of the Contract Term by up to 20%, in total, by giving the Company at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought. For the avoidance of doubt, regardless of the number of notices provided, the total capacity reduction under this provision shall not exceed 20%, unless by mutual agreement between the Large Load Customer and Company, which the Company shall only grant in circumstances that are beneficial, or at least not detrimental, to the Large Load Customer, the Company, and all other customers.

Large Load Customer may terminate its contract or reduce its contract capacity beyond 20% at any time after the first five years of the Contract Term by giving the Company at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought, subject to payment of a capacity reduction/termination fee ("Exit Fee"). The Exit Fee shall be due and payable to the Company upon the effective date of the contract termination or the effective date of the capacity reduction. The Exit Fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost addressed in another rider's) contribution to the Minimum Charge. The Exit Fee Period is defined as the Large Load Customer's then remaining Initial Contract Term, or any agreed extension. The Exit Fee Period shall not be less than one (1) year and shall not exceed five (5) years. In the event of a permanent closure, the customer shall notify the Company within three (3) business days of making this determination.

Following receipt of proper notice, through the Exit Fee Period, the Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. The remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.

(Cont'd to Sheet No. 21.5)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.4)

If there is an issue concerning the calculation of the Exit Fee or delivery of any mitigation amounts, that either the Company or Large Load Customer view as in need of escalation, either the Company or Large Load Customer may request escalation. Such request shall be made in writing and within 14 business days of the Large Load Customer being notified regarding the Exit Fee calculation. In such instance, management representatives for the Company and for the Large Load Customer will discuss and seek to resolve any issues. The management discussion shall occur within 14 business days of a request, unless otherwise agreed to in writing by the Company and Large Load Customer. The Company and Large Load Customer agree to use this escalation process in good faith, escalating only those matters appropriate for management's consideration. This dispute resolution process does not limit or otherwise affect the ability of either Large Load Customer or the Company to file a formal proceeding requesting the Commission to resolve the dispute.

Large Load Customer shall not assign any of its rights or delegate any of its obligations under the Contract without the written consent of the Company. An assignment will not relieve the Large Load Customer of its financial obligation hereunder unless the Company so consents in writing. Such consent(s) shall not be unreasonably withheld. An assignment or delegation in violation of these Terms and Conditions is null and void.

Monthly Billing Demand.

The Monthly Billing Demands for Large Load Customers in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the Off-Peak Hour Provision, but the monthly demand so established shall in no event be less than the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months. The Metered Voltage adjustment, as set forth above, shall not apply to the Large Load Customer's minimum Monthly Billing Demand.

(Cont'd to Sheet No. 21.6)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.5)

Minimum Charge.

Large Load Customers are subject to a minimum monthly charge for each plant equal to the sum of: (a) the Monthly Service Charge; (b) the product of the Minimum Demand Charge and the Monthly Billing Demand; (c) the product of the Step 1 Embedded Capacity Charge and the Monthly Billing Demand; and (d) the sum of the product of each demand charge in all applicable demand related riders in effect at the time and the Monthly Billing Demand. The Step 1 Embedded Capacity Charge rate will be computed as follows: (Block 1 Energy Rate less Block 2 Energy Rate) multiplied by Block 1 Energy Hours less (Minimum Demand Charge less Demand Charge).

The Step 1 Embedded Capacity Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Step 1 Embedded Capacity Charge ($/kW)
327	Secondary	13.289
322	Primary	12.427
323	Subtransmission	12.271
324	Transmission	10.959

(Cont'd to Sheet No. 21.7)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.6)

Collateral Requirements.

In addition to the terms in Items 4 and 14 of the Company's Terms and Conditions of Service, the Large Load Customer shall provide collateral to the Company ("Collateral Requirement") based upon the creditworthiness of the Large Load Customer and as outlined below. The amount of collateral to be provided is equal to twenty-four (24) multiplied by: (a) during the first year of the contract, the maximum expected monthly non-fuel bill; or (b) after the first year of the contract, the Large Load Customer's previous maximum monthly non-fuel bill. The amount of collateral under the foregoing calculation will be recomputed annually, and the Large Load Customer shall have to provide the recomputed amount if it is 10% or more greater than the current amount held. A Large Load Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. A Large Load Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the Collateral Requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Large Load Customer's liquidity meets the ten times threshold) shall be exempt from 50 percent of the Collateral Requirements not to exceed an exemption of more than $250 million. The Collateral Requirement must be provided in one or more of the following forms:

a. A guarantee from the ultimate parent or a corporate affiliate of the Large Load Customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) liquidity greater than ten times the Collateral Requirement; or

b. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Large Load Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. Cash for the full Collateral Requirement.

Tariff I.G.S.
(Industrial General Service)

Availability of Service
Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet average maximum requirements.

Rate

	Service Voltage				
	Secondary	**Primary**	**Subtransmission**	**Transmission**	
Tariff Code	356	358/370	359/371	360/372	
Service Charge per Month	$276.00	$276.00	$794.00	$1,353.00	
Demand Charge per kW					
Of monthly on-peak billing demand	$32.31	$29.96	$21.51	$21.15	IIII
Of monthly off-peak billing demand	$2.00	$1.89	$1.89	$1.80	IIII
Energy Charge per kWh	3.575¢	3.392¢	3.478¢	3.426¢	RRRR

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand………………………………….. $0.69/KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission	
$30.88 / kW	$27.70 / kW	$19.94 / kW	$19.36 / kW	IIII

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

Minimum Charge
This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27	
Demand-Side Management Adjustment Clause	Sheet No. 28	
System Sales Clause	Sheet No. 29	
Fuel Adjustment Clause	Sheet No. 30	
Purchase Power Adjustment	Sheet No. 31	
Generation Rider	Sheet No. 32	N
Environmental Surcharge	Sheet No. 33	T
Decommissioning Rider	Sheet No. 34	
Securitized Surcharge Rider	Sheet No. 35	
Federal Tax Cut Tariff	Sheet No. 36	
Deferred Tax Liability Rider	Sheet No. 37	N
City's Franchise Fee	Sheet No. 38	
School Tax	Sheet No. 39	

Continued on Sheet 8-2

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
EFFECTIVE
3/1/2026
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DATE OF ISSUE: May 8, 2026
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Amy J. Elliott
TITLE: Vice President, Regulatory & External Affairs
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated February 28, 2026 and March 12, 2026

Tariff I.G.S. Continued
(Industrial General Service)

Delayed Payment Charge
Delayed payment charges applicable to this rate schedule are found in Terms and Conditions of Service, Section 5.C., Sheet No. 2-5. T

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

Term of Contract
Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiplies of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

Continued on Sheet 8-3

DATE OF ISSUE: May 8, 2026
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Amy J. Elliott
TITLE: Vice President, Regulatory & External Affairs
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated February 28, 2026

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
EFFECTIVE
3/1/2026
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Tariff I.G.S. Continued
(Industrial General Service)

Special Terms and Conditions Continued

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP or by special agreement with the Company. T

Applicable on and after March 18, 2025, to existing commercial and industrial customers that add 150 MW or more of incremental load and new commercial and industrial customers that have contract demands of at least 150 MW. The following terms and conditions apply:

Contracts will be made for an initial period of twenty (20) years and shall remain in effect thereafter unless cancelled or modified pursuant to the terms hereunder.

Either party shall give at least five years' written notice to the other of the intention to discontinue service under the terms of this Schedule. Such notice shall not reduce the twenty-year initial term. In the event of a permanent closure by the customer occurring after the first five (5) years of the initial contract term, the customer may exit the contract by providing a one-time payment equal to five (5) years of minimum billing under this Schedule.

The customer shall give at least five (5) years' written notice to the Company of the intention to reduce the contract capacity specified in the contract, but any contract capacity changes may be implemented with less than five (5) years notice with mutual agreement. Such notice shall not reduce the maximum contract capacity established during the term of the contract by more than 20%, except by mutual agreement. Such notice shall not be given and will not be accepted during the first five (5) years of the initial contract term.

In addition to the Monthly Billing Demand provisions, the customer's monthly billing demand shall in no event be less than 90% of the greater of (a) the customer's on-peak contract capacity or b) the customer's highest previously established monthly billing demand during the past 11 months or (c) the customer's maximum demand created during the billing month.

The customer shall provide collateral in a form acceptable to the Company based upon the creditworthiness of the customer. The amount of collateral provided shall be equal to 24 times the customer's previous maximum monthly non-fuel bill. During the first year of the contract, the maximum expected bill for the year shall be used. The amount of collateral to be provided will be recomputed annually, and updated if the recomputed value is 10% greater than the current amount held.

DATE OF ISSUE: May 8, 2026
DATE EFFECTIVE: Services Rendered On And After March 1, 2026
ISSUED BY: /s/ Amy J. Elliott
TITLE: Vice President, Regulatory & External Affairs
By Authority of an Order of the Public Service Commission
In Case No.: 2025-00257 Dated February 28, 2026

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts and where the meter is located on the Company side of the substation transformer, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Demand Charge:

Non-Capacity	Capacity	Total	
$*6.09*	$*10.37*	$*16.46*	per kW of On-Peak Billing Demand during the billing months of June - September
$*5.26*	$*9.62*	$*14.88*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity	
$*9.41*	per kW of On-Peak Billing Demand during the billing months of June - September
$*8.76*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity	
$*0.041312*	per kWh for all On-Peak kWh during the billing months of June - September
$*0.026793*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.025907*	per kWh for all On-Peak kWh during the billing months of October - May
$*0.022495*	per kWh for all Off-Peak kWh during the billing months of October - May

(Continued on Sheet No. D-60.00)

Issued April 24, 2026 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after May 1, 2026

Issued under authority of the
Michigan Public Service Commission
dated March 27, 2026
in Case No. U-21870

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$*6.03*	$*10.21*	$*16.24*	per kW of On-Peak Billing Demand during the billing months of June - September
$*5.21*	$*9.47*	$*14.68*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity	
$*9.26*	per kW of On-Peak Billing Demand during the billing months of June - September
$*8.62*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity	
$*0.040900*	per kWh for all On-Peak kWh during the billing months of June - September
$*0.026526*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.025648*	per kWh for all On-Peak kWh during the billing months of October - May
$*0.022270*	per kWh for all Off-Peak kWh during the billing months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$*5.96*	$*10.06*	$*16.02*	per kW of On-Peak Billing Demand during the billing months of June - September
$*5.15*	$*9.33*	$*14.48*	per kW of On-Peak Billing Demand during the billing months of October - May

Transmission Charge:

Non-Capacity	
$*9.13*	per kW of On-Peak Billing Demand during the billing months of June - September
$*8.50*	per kW of On-Peak Billing Demand during the billing months of October - May

Energy Charge:

Non-Capacity	
$*0.040427*	per kWh for all On-Peak kWh during the billing months of June - September
$*0.026219*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.025351*	per kWh for all On-Peak kWh during the billing months of October - May
$*0.022012*	per kWh for all Off-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $*6.68* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $*3.61* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $*2.37* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above or below .875, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is higher than .875, a $1.14 per Kilovar credit will be applied to the amount which the average lagging Kilovar demand during the billing period is below that for an average Power Factor of .875. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .875, a per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of .875 in accordance with the following table:

Power Factor	Penalty
0.700 to 0.874	$1.14 per Kilovar
Below 0.700	$1.14 per Kilovar first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A $5.25 per Kilovar penalty will be applied to the amount by which the average lagging Kilovar demand during the billing period is in excess of that for an average Power Factor of 0.875, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the $5.25 per Kilovar penalty applies again.

(Continued on Sheet No. D-62.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate (Contd)

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>
Substation Ownership Credit: $*(1.93)* per kW of Maximum Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>
Substation Ownership Credit: $*(1.82)* per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate (Contd)

Aggregate Peak Demand Service Provision (GAP)

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW. *Not withstanding the specific requirements outlined in this provision, the Company may, at its sole discretion, allow participation by customers who do not fully meet one or more of the stated eligibility criteria, including but not limited to the number of accounts or demand thresholds.*

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $*(0.000205)* per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

<u>Annual Power Test Requirement</u>

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

<u>Conditions of Interruption</u>

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate (Contd)

Interruptible Service Provision (GI) (Contd)

Conditions of Interruption (Contd)
Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption
Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$*(8.50)*	per kW of On-Peak Billing Demand during the billing months of June - September
	$*(7.50)*	per kW of On-Peak Billing Demand during the billing months of October - May

Interruptible Service Provision – Market-Price Option (GI2)

Availability

This provision is available to any Full Service GPD customer account willing to designate at least 3,000 kW of On-Peak Billing Demand as Defined Interruptible Capacity. A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season. The Company reserves the right to limit the amount of designated interruptible load available to any single customer, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to designate less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm Capacity and Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 10th of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges: These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge:	$*0.033010* per kWh for all kWh during the billing months of June - September
	$*0.031900* per kWh for all kWh during the billing months of October - May

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge:	$*0.031449* per kWh for all kWh during the billing months of June - September
	$*0.029198* per kWh for all kWh during the billing months of October - May

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh
Capacity & Transmission Charge:	$*0.029081* per kWh for all kWh during the billing months of June - September
	$*0.026985* per kWh for all kWh during the billing months of October - May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.986*%
Customer Voltage Level 2	*1.359*%	*2.247*%
Customer Voltage Level 3	*3.268*%	*6.502*%

Delivery Charges: These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge
If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer’s load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company’s ability to implement emergency electrical procedures as described in the Company’s Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company’s control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company’s Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-6*7.10*)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Coincident Peak Demand Provision (CPD)

This provision is available to any customer on Rate GPD but limited to the first three customers enrolled in the provision. Customers served under this provision will be charged capacity and transmission through a volumetric on peak energy charge as stated below. This will be charged on all energy consumed during the on peak window, from 11 AM to 7 PM. They will pay the On Peak Demand Charge on all demand during the coincident peak window of 4 PM to 6 PM. Customers served under this provision will be subject to Critical Peak Event Pricing.

Critical Peak Event Determination

A Critical Peak Event occurs when a System Integrity Event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed the full on peak demand charge plus $1.00/kWh during the duration of the event.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	$*0.031287*	$*0.031287*	per kWh of On-Peak kWh during the billing months of June - September
NA	$*0.028277*	$*0.028277*	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$*6.09*	$*10.37*	$*16.46*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$*5.26*	$*9.62*	$*14.88*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity	
$*0.017876*	per kWh of On-Peak kWh during the billing months of June - September
$*0.016640*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity	
$*0.026793*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.041312*	per kWh for all On-Peak kWh during the billing months of June - September
$*0.022495*	per kWh for all Off-Peak kWh during the billing months of October - May
$*0.025907*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$*6.09*	$*10.37*	$*16.46*	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of June - September
$*5.26*	$*9.62*	$*14.88*	per kW of On-Peak Billing Demand during a System Integrity Event during the billing months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-67.20)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.10)

Monthly Rate (Contd)

Coincident Peak Demand Provision (CPD) (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	$*0.030044*	$*0.030044*	per kWh of On-Peak kWh during the billing months of June - September
NA	$*0.027129*	$*0.027129*	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$*6.03*	$*10.21*	$*16.24*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$*5.21*	$*9.47*	$*14.68*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

Transmission Charge:

Non-Capacity	
$*0.017130*	per kWh of On-Peak kWh during the billing months of June - September
$*0.008416*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity	
$*0.026526*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.040900*	per kWh for all On-Peak kWh during the billing months of June - September
$*0.022270*	per kWh for all Off-Peak kWh during the billing months of October - May
$*0.025648*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$*6.03*	$*10.21*	$*16.24*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June - September
$*5.21*	$*9.47*	$*14.68*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October - May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Non-Capacity	Capacity	Total	
NA	$*0.027987*	$*0.027987*	per kWh of On-Peak kWh during the billing months of June - September
NA	$*0.025248*	$*0.025248*	per kWh of On-Peak kWh during the billing months of October - May

Demand Charge:

Non-Capacity	Capacity	Total	
$*5.96*	$*10.06*	$*16.02*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of June - September
$*5.15*	$*9.33*	$*14.48*	per kW of On-Peak Billing Demand during the coincident peak window of 4PM-6PM during the billing months of October - May

(Continued on Sheet No. D-67.30)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.20)

Monthly Rate (Contd)

Coincident Peak Demand Provision (CPD) (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 1 (CVL 1) (Cont)

Transmission Charge:

Non-Capacity

$*0.015940*	per kWh of On-Peak kWh during the billing months of June – September
$*0.014813*	per kWh of On-Peak kWh during the billing months of October - May

Energy Charge:

Non-Capacity

$*0.026219*	per kWh for all Off-Peak kWh during the billing months of June - September
$*0.040427*	per kWh for all On-Peak kWh during the billing months of June – September
$*0.022012*	per kWh for all Off-Peak kWh during the billing months of October - May
$*0.025351*	per kWh for all On-Peak kWh during the billing months of October - May

Critical Peak Event:

Non-Capacity	Capacity	Total	
$*5.96*	$*10.06*	$*16.02*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of June – September
$*5.15*	$*9.33*	$*14.48*	per kW of On-Peak Billing Demand during a System Integrity Event during the calendar months of October – May
NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event

(Continued on Sheet No. D-67.40)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.30)

Monthly Rate (Contd)

Large Load Customer Provision

Availability

A Large Load Customer is defined as either (i) a customer with a load of 100 MW or more at a single site, or (ii) a customer with multiple sites, each with a load of 20 MW or greater which in total equal 100 MW or greater, owned by the same entity and located within the Company's service territory.

A Large Load Customer must agree to a rate contract term for an initial period of a minimum of fifteen (15) years from the initial service date for billing purposes. The minimum contract term shall commence after a negotiated ramp-up period not exceeding five (5) years, as determined by the Company. The ramp-up period will be specified at the time of contract execution and will be included in the contract terms.

At the conclusion of the initial contract term, the contract shall automatically renew in five-year contract extensions unless the Large Load Customer provides four (4) years advance written notice of the intention to terminate the contract. Large Load Customer Provision rate contracts are subject to Commission approval.

Financial Security

Consumers Energy is authorized to require additional financial security from Large Load customers receiving service under this rate. Unless otherwise approved by the Commission, the Large Load Customer shall provide collateral in the amount of 50% of the Exit Fee. This amount shall be recalculated annually or upon any material change to the contract term or minimum monthly charges. The Collateral Requirement may be reduced over the course of the contract term to reflect the Company's declining financial exposure, provided the Customer remains in full compliance with all terms and conditions of the rate contract.

The Collateral Requirement may be provided to the Company in one or both of the following forms:

a) A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Large Load Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

b) Cash for the full Collateral Requirement. Cash collateral shall accrue interest at a rate approved by the Commission and will be returned, in whole or in part, as the Collateral Requirement is reduced or upon satisfaction of all contractual obligations.

The Company may, at its discretion, require a different collateral amount or accept a form of collateral other than described above, subject to Commission review and approval.

The authorization in this tariff does not limit the Company's other authority to impose other financial security requirements from customers.

Minimum Billing Demand

The Company shall require a monthly Minimum Billing Demand of 80% of the Contract Capacity, defined as the amount of capacity reserved for the Large Load Customer. The Minimum Billing Demand shall be applicable to the Maximum Demand and the On-Peak Billing Demand, including the Transmission Charge, for the term of the rate contract. The Large Load Customer's Maximum Demand and On-Peak Billing Demand, including the Transmission Charge, shall not be less than the Customer's Minimum Billing Demand, regardless of the Customer's actual usage.

(Continued on Sheet No. D-67.50)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.40)

Monthly Rate (Contd)

Large Load Customer Provision (Contd)

Contract Capacity

The Large Load Customer shall specify the amount of capacity to be reserved for its use in its rate contract with the Company, which is defined as the Contract Capacity.

The Company reserves the right, at its sole discretion, to allow a one-time reduction, not to exceed 10% of Contracted Capacity, to the Contract Capacity if requested by the Large Load Customer. A minimum of 48 months advance written notice must be provided for the requested reduction. A requested reduction to Contract Capacity will be granted if the reduction will not result in cost increases for the Company or its other customers, and will be documented in an amendment to the rate contract. The Customer shall not assign, transfer, or otherwise convey any portion of Contract Capacity to another party without prior written consent of the Company and approval by the Commission.

If the Large Load Customer's usage exceeds the Contracted Capacity by 1,000 kW or more, the Company shall amend the contract to reflect the increased usage if the Company determines it has the capacity to serve the additional load without negatively impacting other customers or the Company. If the Company determines it does not have capacity to serve the additional load without negatively impacting other customers or the Company, it shall inform the Customer that it must reduce its usage to its Contract Capacity. If the Customer does not comply with the request to reduce its usage to its Contract Capacity, the Company is authorized to suspend service to the Customer until the Customer complies with the requirement to limit its usage to its Contract Capacity.

The Large Load Customer will be responsible for any additional costs incurred due to changes in the Contract Capacity and usage above its Contract Capacity. If the Customer seeks to reduce its Contract Capacity by more than 10% or seeks an additional reduction after the discretionary one-time reduction, then the customer must pay a portion of the Exit Fee prorated to the percentage of the reduction in Contract Capacity unless determined otherwise by the Commission.

Administrative Fee

An Administrative Fee shall be imposed to cover the costs associated with providing project proposals to Large Load Customers. This fee will be charged directly to the entity requesting the proposal and is non refundable. The Administrative Fee shall be $100,000 per project proposal and shall be reconciled to actual costs upon completion of the project.

Exit Fee

In the event the Large Load Customer ceases to take power supply service from the Company at the Customer’s Facility, the Company shall be entitled to recover an Exit Fee from the Customer. The Exit Fee shall be calculated by multiplying the Minimum Billing Demand plus the System Access Charge by the number of months remaining in the rate contract term as of the date the Customer ceases to take power supply service from the Company. The Company may reduce the Exit Fee if it determines, in its sole discretion, that the loss of Customer’s load will not harm the Company or its other customers. The Exit Fee will apply throughout the entire contract term, including any ramp-up period, and shall be calculated based on the Minimum Billing Demand applicable at the time of exit.

(Continued on Sheet No. D-68.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-*67.50*)

Monthly Rate (Contd)

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.8., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

(Continued on Sheet No. D-69.00)

Issued December 3, 2025 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after November 7, 2025

Issued under authority of the
Michigan Public Service Commission
dated November 6, 2025
in Case No. U-21859

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate (Contd)

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges. *Large Load Customers shall also be required to meet the Minimum Billing Demand.*

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate may require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, (vi) service under the Demand Response Program or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

Customers participating in the Large Load Customer Provision shall require a written rate contract with an initial term of at least fifteen years, which shall begin after any applicable ramp up period specified in the rate contract. At the conclusion of the initial contract term, the contract shall automatically renew in five-year contract extensions unless the Large Load Customer provides four (4) years advance written notice of the intention to terminate the contract. Large Load Customer Provision rate contracts are subject to Commission approval.

SCHEDULE DCT
(Data Center Tariff)

Definitions

For purposes of this schedule:

“Contract” means the service agreement entered into by the customer and the Company in accordance with this schedule.

“Contract Capacity” means the mutually agreed amount of monthly peak load requirements for each month during the remaining term after the Load Ramp Period as set forth in the contract for service, whereby the Company agrees to provide all of the components of retail electric service (which could include either default SSO supply or access to CRES provider supply of generation service) subject to the terms and conditions in its tariffs and the customer agrees to purchase service at that level for the stated term of the contract under the same terms and conditions.”

“Customer”—whether or not capitalized and unless specifically identified as Existing Load or New Load—refers to any customer to whom Schedule DCT applies, including both Existing Load and New Load.

“Data Center” means a centralized facility (a) used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information through the use of computer systems, servers, networking equipment, and related components that (b) has an aggregate monthly maximum demand of greater than 25,000 kW. Unless otherwise specified, the term “Data Center” shall include “Mobile Data Center.”

“Mobile Data Center” means a centralized facility (a) used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information (including mining of cryptocurrency) through the use of computer systems, servers, networking equipment, and related components that (b) has an aggregate monthly maximum demand of greater than 25,000 kW and has load that is portable and/or distributable, including but not limited to structures that are not affixed to the ground or are easily removed from a location.

“Single Location” refers to an area that is owned, operated, or leased by the Data Center customer with the metering point for the customer’s metering point. A contiguous lot (or lots) to the area with the customer’s metering point may be considered the customer’s premises regardless of easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way, so long as it would not create an unsafe or hazardous condition.

“Load Ramp Contract Capacity” means the mutually agreed monthly peak load requirements associated with the Load Ramp Period. The Load Ramp Contract Capacity shall not be less than:

In Year 1, 50% of Contract Capacity.
In Year 2, 65% of Contract Capacity.
In Year 3, 80% of Contract Capacity.
In Year 4, 90% of Contract Capacity.

“Load Ramp Period” refers to the time of commencement of service until the customer reaches full contract capacity, which shall not exceed four years.

SCHEDULE DCT
(Data Center Tariff)

“Existing Load” means Data Center load for which a letter of agreement or electric service agreement has already been signed by the Effective Date of Schedule DCT. “Existing Load” does not include Data Center load for which a customer signs a new electric service agreement to expand its Existing Load by more than 25,000 kW of New Load above the contract capacity under the existing electric service agreement after the Effective Date of Schedule DCT. At the customer’s request, AEP Ohio will use reasonable efforts to separately meter the New Load and the Existing Load, but it may not be technically feasible to do so. If it is technically feasible to separately meter, the customer will pay all costs reasonably incurred by AEP Ohio to complete such separate metering. If the load is not separately metered, then the Existing Load will lose its Existing Load status and will be considered New Load for purposes of this Schedule DCT.

“New Load” means (a) Data Center load for which a letter of agreement or electric service agreement was signed after the Effective Date of Schedule DCT or (b) Existing Load that signs a new ESA to increase its contract capacity by more than 25,000 kW. “New Load” does not include Existing Load that signs a new ESA to expand its contract capacity by 25,000 kW or less; provided, however, that all expansions remain subject to available transmission and distribution capacity at the customer location and the customer’s satisfaction of all other applicable requirements, including execution of an LOA and ESA and payment of any required CIAC. (If an Existing Load separately meters an expansion greater than 25,000 kW, as described in the definition of “Existing Load,” the separately metered expansion shall constitute New Load, and the separately metered original load shall continue to constitute Existing Load.)

“Effective Date of Schedule DCT” means the date Schedule DCT became effective following the Commission’s order in Case No. 24-508-EL-ATA.

Availability of Service

Service pursuant to this schedule is available for general service to customers that operate a Data Center (both Existing Load and New Load) that will use, within the initial contract term, a monthly maximum demand of greater than 25,000 kW at a Single Location or an aggregated Total Customer Contract Capacity in Service Territory of greater than 25,000 kW as described below.

If the customer facility operates one or more Data Centers with a monthly maximum demand of greater than 25,000 kW and has non-Data Center load (that would otherwise be billed under the General Service or other applicable Schedule) at a Single Location, Schedule DCT will apply to all electric distribution service to that customer, provided, however, that the customer shall have the option of separately metering its Data Center and non-Data Center loads (if technically feasible) and paying for those loads through separate customer accounts. In such situation, the customer shall be responsible for all metering and other costs necessary to separate its load into separate customer accounts.

The terms and conditions of service under this this schedule shall apply upon a request for service by an eligible customer but service to customers under this schedule will not commence until the Company has sufficient capacity to meet the contractual load requirements.

With Commission approval, service to a Schedule DCT customer may be suspended by AEP Ohio if customer usage exceeds its Contract Capacity by more than 1,000 kW. If the Company determines that additional capacity is available from AEP Ohio to serve additional load at the customer site, the Company may also seek mutual agreement to adjust the Contract Capacity and reserves the right to raise the issue before the Commission if there is no agreement.

SCHEDULE DCT
(Data Center Tariff)

Monthly Rate

Schedule Code	Service Voltage	Distribution Demand Charge ($/kW)	Excess Reactive Demand ($/kVA)	Customer Charge ($)
296,796	Secondary	9.05	1.67	21.00
295,795	Primary	8.08	1.62	186.30

Schedule Code	Service Voltage	Excess Reactive Demand ($/kVAR)*	Customer Charge ($)	Supplemental Customer Charge ($)**
297,797	Transmission	0.95	6,800	20,000

*For each kVAR of reactive demand, leading or lagging, in excess of 50% of the kW metered demand.
**This is not a base distribution rate and will not be included in base distribution rider charges and will not apply to Existing Load.

Minimum Charges

The minimum monthly charge under this schedule shall be the sum of the customer charge, the product of the distribution demand charge and the monthly distribution billing demand, and all Commission-approved riders shown on Sheet Number 104-1.

Monthly Billing Demand – Existing Load

For Existing Load, billing demand in kW shall be taken each month as the single highest 30-minute integrated peak in kW as registered during the month by a 30-minute integrating demand meter. The monthly billing demand established hereunder shall not be less than 60% of (a) the customer contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Monthly Billing Demand – New load

For New Load, billing demand in kW shall be taken each month as the single highest 30-minute integrated peak in kW as registered during the month by a 30-minute integrating demand meter or indicator, or at the Company's option, as the highest registration of a thermal-type demand meter. The customer will have no more than the Load Ramp Period to reach full contract capacity, during which time monthly billing demand shall not be less than 85% of the customer's Load Ramp Contract Capacity. After the Load Ramp Period, monthly billing demand established hereunder shall not be less than the greater of (a) 85% of the customer's highest previously established monthly billing demand during the past 11 months or (b) the customer's "Minimum Demand" as set forth below:

SCHEDULE DCT
(Data Center Tariff)

Total Customer Contract Capacity in Service Territory	Minimum Demand
25,001 kW to 75,000 kW	15,000 kW plus 85% of marginal amount over 25,000 kW
75,001 kW and above	57,500 kW plus 100% of marginal amount over 75,000 kW; provided, however, that the minimum demand will not exceed 85% of the total contract capacity.

All New Loads of affiliated companies and companies with common ownership greater than 25,000 kW will be considered in the aggregate for purposes of determining the “Total Customer Contract Capacity in Service Territory” and calculating the “Minimum Demand” in the chart above that will be included for the full term of each Contract for New Load under this Schedule DCT. Existing Load will not be considered as part of the “Total Customer Contract Capacity in Service Territory.” All affiliated New Load will be stacked in order of the energization date so the Minimum Demand can be applied based on multiple Contracts, as applicable. If there are multiple New Loads at a Single Location of less than 25,000 kW (but the aggregate total load is greater than 25,000 kW), all of those New Loads will be subject to Schedule DCT.

Unless otherwise mutually agreed by the Company and the customer, the customer shall be billed under the provisions of this tariff using the Contract Capacity during all months of the initial term of contract should the customer fail to energize service. The monthly billing demand defined hereunder shall apply for purposes of billing under all applicable riders, regardless of any conflicting provision in the rider.

Delayed Payment Charge

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 21 days after the mailing of the bill. On all accounts not paid by the due date, an additional charge of 2.5% of the unpaid balance will be due.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the Commission-approved riders on Sheet Number 104-1 that apply to Demand Metered commercial and industrial service. Nothing in this tariff excepts eligible customers from other riders or applicable tariffs.

Generation Service

Customers receiving service under this schedule may select competitive service from a CRES Provider or Standard Offer Service. The Company requires that Company-owned metering be installed to monitor the customer's load.

Transmission Service

Customers receiving service under this schedule shall pay the charges established for Demand Metered Service under the Basic Transmission Cost Rider (“BTCR”). New Loads receiving service under this schedule are not eligible to participate in the 1CP or 6CP BTCR Programs or any successor programs. Existing Load currently participating in the 1CP and 6CP BTCR pilots can stay on these pilots until the end of ESP V. Any data center not currently on the 1CP or 6CP BTCR pilot will not be eligible to be added to the pilots.

Terms of Contract – Existing Load

The terms of existing Contracts for Existing Load (including without limitation terms related to contract length, contract capacity, and load ramp) will continue until terminated according to the terms of the Contract. The Company shall not be required to supply capacity in excess of the Contract Capacity except by mutual agreement.

Terms of Contract – New Load

For New Load only, contracts under the Schedule shall be made for an initial period of not less than the Load Ramp Period plus 8 years. By way of example, the initial period of a Contract for a Data Center with a 4-year Load Ramp Period will be 12 years. If electric infrastructure is not in place to serve the customer by the Contract's estimated in-service date, the customer may petition the Commission for an adjustment to the contract term based on the facts and circumstances presented at that time (but will otherwise remain the Load Ramp Period plus 8 years).

After the initial term, Contracts shall remain in effect unless terminated by either party by providing written notice to the other party no later than three (3) years prior to the requested date of termination. After the initial term, either party may request a modification to the Contract Capacity by providing written notice to the other party no later than three (3) years prior to the requested modification date. During the initial term of the Contract, the customer will be financially responsible to pay the minimum charges regardless of the customer choosing to curtail, reduce, suspend, or terminate service. If after completion of the fifth year of the Contract after the Load Ramp Period the customer chooses to pay an exit fee equal to minimum charges for 36 months after notice of termination, the customer can thereafter terminate the contract. By way of example, a customer with a 3-year Load Ramp Period may pay the exit fee and terminate the contract only after Year 8 of the Contract.

The customer shall agree with the Company in advance its Load Ramp Contract Capacity and a final Contract Capacity value to be used for the remaining initial term of the contract. A new contract will be required for any load additions in excess of 100 kW.

The Company shall not be required to supply capacity in excess of the Contract Capacity except by mutual agreement.

Nothing in this Schedule limits the requirement that a customer sign a Letter of Agreement for network and customer- specific investment prior to energization or Contribution in Aid of Construction agreement for customer-specific investment.

To sign a contract under this Schedule, the customer must designate a specific site at which its Data Center project will be constructed and served by the Company, and the customer must own or have the exclusive right to use the land for this purpose.

SCHEDULE DCT
(Data Center Tariff)

Collateral Requirement – Existing Load

Collateral for Existing Loads will be governed by the collateral terms of the existing Letter of Agreement and Electric Service Agreement between the customer and the Company.

Collateral Requirement – New Load

For New Load only, the customer, if not having both (a) a credit rating of at least A- from S&P Global Inc. ("S&P") and A3 from Moody's Corporation ("Moody's") and (b) cash and cash equivalents on an audited balance sheet prepared in accordance with Generally Accepted Accounting Principles ("GAAP") ("Liquidity") greater than ten times the Collateral Requirement, must provide a guarantee or collateral at the time of signing the contract equal to 50% of the total minimum charges for the full term of the contract ("Collateral Requirement"), calculated based on AEP Ohio's rates in effect at the time the Collateral Requirement is provided. The Collateral Requirement must be provided in one or more of the following forms:

1. A guarantee from the ultimate parent or a corporate affiliate of the customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) Liquidity greater than ten times the Collateral Requirement; or

2. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company.

3. Cash for the full Collateral Requirement.

The amount of the Collateral Requirement will be reduced by one year's minimum charges for each year the customer is energized and makes on-time electric service payments under the contract.

If the financial condition of the customer or guarantor changes – or market conditions (including ownership/structural changes) change – over the term of the contract, the Company may request updated information to reevaluate the customer and its collateral requirements, which may be adjusted accordingly.

Customer-Owned Generation and Emergency Conditions

Consistent with Ohio Administrative Code Chapter 4901:1-22, Schedule DCT Customers shall enter into an interconnection agreement between the Company and the Customer in advance of connecting any source of power other than the delivery point specified in the Contract. Emergency or backup generation that is not designed to operate in parallel with the Company's system is not subject to the additional requirements in this section.

SCHEDULE DCT
(Data Center Tariff)

With Commission approval, service to any customer using behind-the-meter generation to serve some or all of its demand that elects not to offset its Contract Capacity with output from its behind-the-meter generation may be suspended by AEP Ohio if customer usage exceeds its Contract Capacity by more than 1,000 kW.

If the customer elects to use its behind-the-meter generation to offset the customer's Contract Capacity (either in initially establishing service or in the context of a subsequent load expansion or behind-the-meter generation expansion at the same site, as reflected in a new or updated Contract Capacity), the following requirements will apply. In order to ensure that the Customer's election to net does not result in it exceeding its Contract Capacity, equipment must be in place and maintained through the term of the Electric Service Agreement to instantaneously curtail load equal to or greater than the behind-the-meter generation output, subject to the then-current technical requirements of the transmission provider. If the equipment fails and results in the customer exceeding its Contract Capacity, the Company reserves the right to raise before the Commission any unresolved reliability or safety concerns based on the facts and circumstances presented at that time.

Nothing in this paragraph affects AEP Ohio's right to disconnect or curtail load in accordance with Section 26 of the Terms and Conditions of Service in the Company's tariff and Ohio Administrative Code 4901:1-10-16.

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

Customers served under this tariff agree to written attestation as part of its Contract that the customer will follow all applicable technical operating requirements, such as not intentionally or unintentionally cycling load in a way that creates an imbalanced or unacceptable system frequency, and other requirements that will be maintained and periodically updated for the safety of the larger system. Upon detection of any activities outside of the technical requirements, the Company has the right to disconnect.

With Commission approval, service may be suspended by AEP Ohio to a customer under Schedule DCT (including a customer with behind-the-meter generation that has elected not to net its Contract Capacity) if the customer usage exceeds its Contract Capacity by more than 1,000 kW. If additional capacity is available at the customer site, the Company may also seek mutual agreement to adjust the Contract Capacity and reserves the right to raise the issue before the Commission if there is no resolution. Nothing in this paragraph affects the provision above regarding behind-the-meter generation or is intended to preclude the Company from disconnecting service or curtailing load to a Schedule DCT customer without Commission approval in accordance with Section 26 of the Terms and Conditions of Service in the Company's tariff and Ohio Administrative Code 4901:1-10-16.

Prior to receiving service, Mobile Data Center customers will be required to provide a sworn statement, under penalty of perjury, that neither the customer nor its corporate parent or affiliates are affiliated with or acting on behalf of any foreign adversary as defined in 15 C.F.R. § 7.4. If AEP Ohio has a good faith belief that a Mobile Data Center customer has provided false information in response to this requirement, AEP Ohio has the right to immediately disconnect service to the Mobile Data Center permanently or until adequate proof is shown to satisfy AEP Ohio that the Mobile Data Center customer meets this requirement.

Filed pursuant to Order dated April 1, 2026 in Case No. 25-392-EL-AIR

Issued: April 8, 2026 Effective: April 10, 2026

Issued by
Marc Reitter, President
AEP Ohio

Schedule GS-5
HIGH LOAD/LOAD FACTOR SERVICE

I. APPLICABILITY AND AVAILABILITY

A. Except as modified herein, this schedule is applicable only to a non-residential Customer:

1. Who elects (a) to receive Electricity Supply Service and Electric Delivery Service from the Company or (b) who is eligible for and elects to purchase Electricity Supply Service from a Competitive Service Provider in accordance with Va. Code § 56-577 A., with one or more accounts on contiguous property as described in Section IV.E.1. of these Terms and Conditions for the Provision of Electric Service ("Terms and Conditions").

2. Whose contracted demand or maximum measured demand is equal to or exceeds 25 megawatts ("MW") with such usage occurring for at least three billing months, of the current and previous eleven billing months; and whose load factor:

a. For existing customers, reaches 75% or higher, as measured according to Paragraph IX. with such usage occurring for at least three billing months, of the current and previous eleven billing months; or

b. For Customers requesting new or expanded service, is expected to be 75% or higher.

B. A Customer served under this schedule may take service as a transmission voltage Customer, primary voltage Customer, or secondary voltage Customer.

C. The Customer shall not reduce or assign contracted demand without the express written consent of the Company. Such reduction or assignment shall be governed by the provisions of Section XXVII. of the Terms and Conditions.

D. Qualifying Demands and Load Factor

1. For a Customer served under this schedule whose Actual Monthly Load Factor is less than 75% as measured according to Paragraph IX., this schedule shall remain applicable to the Customer until such time as the Customer's load factor is less than 75% during all billing months within the most recent 24 billing months.

2. For a High Load Customer served under this schedule whose maximum measured demand has decreased to less than or not reached 25 MW, this schedule shall remain applicable. However, if the High Load Customer's contracted demand has decreased to less than 25 MW pursuant to Section XXVII. of the Terms and Conditions, this schedule shall not remain applicable.

(Continued)

I. APPLICABILITY AND AVAILABILITY (Continued)

E. At such time the Customer no longer meets the above applicability requirements, the Customer shall remain on this schedule for the period (not exceeding two additional billing months) required to achieve an orderly transfer to the applicable schedule.

F. For Customers who elect to purchase Electricity Supply Service from a Competitive Service Provider, the provision of Electric Service under this Schedule shall not continue to be available to the Customer until an *Agreement for Electric Service* the Company may require is executed between the Company and the Customer.

II. 30-DAY RATE

A. Distribution Service Charges

1. Basic Customer Charge

a. Secondary Service Voltage
Basic Customer Charge $551.91 per billing month.

b. Primary or Transmission Service Voltage
Basic Customer Charge $551.91 per billing month.

2. Plus Distribution Demand Charge

a. Secondary Service Voltage		
All kW of Distribution Demand	@	$4.497 per kW
b. Primary or Transmission Service Voltage		
First 5,000 kW of Distribution Demand	@	$3.495 per kW
Additional kW of Distribution Demand	@	$3.495 per kW

3. Plus rkVA Demand Charge

a. Secondary Service Voltage	@	$0.684 per rkVA
b. Primary or Transmission Service Voltage	@	$0.684 per rkVA

4. Plus Distribution kWh Charges

a. Secondary Service Voltage		
All kWh	@	0.0279¢ per kWh
b. Primary or Transmission Service Voltage		
All kWh	@	0.0279¢ per kWh

(Continued)

II. 30-DAY RATE (Continued)

5. Plus each Distribution kilowatt-hour used is subject to all applicable riders in the Exhibit of Applicable Riders, including non-bypassable charges.

6. Plus each kW is subject to all applicable distribution riders in the Exhibit of Applicable Riders, including non-bypassable charges. Such kW shall be the kW of Distribution Demand determined pursuant to Paragraph IV., below.

B. Electricity Supply (ES) Service Charges

Except as modified in Paragraph VI., Paragraphs II.B.1., II.B.3., and II.B.6., are applicable to Customers receiving Electricity Supply Service from a Competitive Service Provider.

1. On-Peak Generation Demand Charge

All On-Peak Electricity Supply Demand for

a.	Secondary Service Voltage	@	\$9.481 per kW
b.	Primary Service Voltage	@	\$9.135 per kW
c.	Transmission Service Voltage	@	\$8.974 per kW

2. Plus Off-Peak Generation Demand Charge

All Off-Peak kW ES Demand	@	\$5.307 per kW

3. Plus Transmission Demand Charge

All On-Peak Electricity Supply Demand for

a.	Secondary Service Voltage	@	\$2.277 per kW
b.	Primary Service Voltage	@	\$2.371 per kW
c.	Transmission Service Voltage	@	\$2.310 per kW

4. Plus Generation kWh Charge

All On-Peak ES kWh	@	0.4648¢ per kWh
All Off-Peak ES kWh	@	0.3299¢ per kWh

5. Plus each Electricity Supply kilowatt-hour used is subject to all applicable riders in the Exhibit of Applicable Riders, including non-bypassable charges, as discussed in Paragraph XII., below.

II. 30-DAY RATE (Continued)

6. Plus each kW of Electric Service Demand determined pursuant to Paragraph VI., below, is subject to all applicable riders in the Exhibit of Applicable Riders, including non-bypassable charges, as discussed in Paragraph XII., below.

C. The minimum charge shall be as set forth in Paragraphs IV. and VI.

III. DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The following On-Peak and Off-Peak hours are applicable to the billing of all charges stated in this schedule.

A. On-Peak hours are as follows:

1. For the period of June 1 through September 30, 10 a.m. to 10 p.m., Mondays through Fridays.

2. For the period of October 1 through May 31, 7 a.m. to 10 p.m., Mondays through Fridays.

B. All hours not specified in Paragraph III.A. are Off-Peak.

IV. DETERMINATION OF DISTRIBUTION DEMAND

A. Distribution Demand shall be billed only where the normal service delivery voltage is less than 69 kV.

B. The Distribution Demand billed under Paragraph II.A.2. shall be the highest of:

1. The highest average kW measured at the location during any 30-minute interval of the current and previous 11 billing months.

1. Eighty-five percent of the Customer's contracted demand.

V. DETERMINATION OF rkVA DEMAND

The rkVA of demand billed shall be the highest average rkVA measured in any 30-minute interval during the current billing.

Schedule GS-5
HIGH LOAD/LOAD FACTOR SERVICE

(Continued)

VI. DETERMINATION OF ELECTRIC SERVICE DEMAND

A. The kW of demand billed under II.B.3. shall be the highest of:

1. The highest average kW measured in any 30-minute interval of the current billing month during On-Peak hours.

2. Seventy-five percent of the highest kW of demand at this location as determined under Paragraph VI.A.1., above, during the billing months of June through September of the preceding 11 billing months, or

3. Eighty-five percent of the Customer's contracted demand.

B. The kW of demand billed under II.B.1. shall be the highest of:

1. The highest average kW measured in any 30-minute interval of the current billing month during On-Peak hours.

2. Seventy-five percent of the highest kW of demand at this location as determined under Paragraph VI.B.1., above, during the billing months of June through September of the preceding 11 billing months, or

3. Sixty percent of the Customer's contracted demand.

C. For Customers who elect to purchase Electricity Supply Service from a Competitive Service Provider, the following provisions apply for the determination of Electric Service minimum charges:

1. Customers who elect to purchase Electricity Supply Service from a Competitive Service Provider shall pay a minimum demand when VI.A.1. is less than Paragraph VI.A.3. Such difference shall be the minimum billable demand.

2. Any Customer who (i) receives service under this schedule and (ii) enrolled with a Competitive Service Provider on or after January 1, 2025 will be subject to Paragraph VI.B.3. Any Customer who receives service under this schedule and (i) enrolled with a Competitive Service Provider prior to January 1, 2025 or (ii) notified the Company in writing during calendar year 2024 of its intent to enroll with a Competitive Service Provider will not be subject to Paragraph VI.B.3.

(Continued)

(Continued)

VII. DETERMINATION OF OFF-PEAK ELECTRICITY SUPPLY DEMAND

The kW of demand billed under Paragraph II.B.2. shall be the Off-Peak demand which is in excess of 90% of the Electric Service Demand determined under Paragraph VI.

VIII. METER READING AND BILLING

When the actual number of days between meter readings is more or less than 30 days, the Basic Customer Charge, the Distribution Demand Charge, the rkVA Demand Charge, the On-Peak Generation Demand Charge, the Off-Peak Generation Demand Charge, the Transmission Demand Charge, and the minimum charge of the 30-day rate will each be multiplied by the actual number of days in the billing period and divided by 30.

IX. DETERMINATION OF QUALIFYING LOAD FACTOR

Qualifying Load Factor means the Customer's actual or expected load factor exceeds 75%.

Load Factor is calculated as:

Monthly kWh ÷ the number of Days in the Billing Month ÷ 24 ÷ the Maximum Measured kW of Demand.

X. STANDBY, MAINTENANCE OR PARALLEL OPERATION SERVICE

A Customer requiring standby, maintenance or parallel operation service may elect service under this schedule provided the Customer contracts for the maximum kW which the Company is to supply. Standby, maintenance or parallel operation service is subject to the following provisions:

A. Suitable relays and protective apparatus shall be furnished, installed, and maintained at the Customer's expense in accordance with specifications furnished by the Company. The relays and protective equipment shall be subject, at all reasonable times, to inspection by the Company's authorized representative.

B. In case the Distribution Demand determined under Paragraph IV. exceeds the contract demand, the contract demand shall be increased by such excess demand.

C. The demand billed under II.A.2. shall be the contract demand.

(Continued)

(Continued)

XI. DEFINITION OF TRANSMISSION, PRIMARY AND SECONDARY VOLTAGE CUSTOMER

A. A transmission voltage Customer is any Customer whose delivery voltage is 69 kV or above and is the voltage that is generally available in the area.

B. A primary voltage Customer is any Customer (a) served from a circuit of 69 kV or more where the delivery voltage is 4,000 volts or more, (b) served from a circuit of less than 69 kV where Company-owned transformation is not required at the Customer's site, (c) where Company-owned transformation has become necessary at the Customer's site because the Company has changed the voltage of the circuit from that originally supplied, or (d) at a location served prior to October 27, 1992 where the Customer's connection to the Company's facilities is made at 2,000 volts or more.

C. A secondary voltage Customer is any Customer not defined in Paragraph XI.A. or XI.B. as a transmission or primary voltage Customer.

XII. NON-BYPASSBLE CHARGES

Any Commission approved non-bypassable charges in the Exhibit of Applicable Riders shall apply to all Customers, irrespective of generation supplier pursuant to Virginia Law, unless the Customer meets the statutory requirements for exemption from such charges.

XIII. TERM OF CONTRACT

The minimum demand charges calculated pursuant to Paragraphs IV. and VI. shall be applicable for ten (10) years from the Customer's execution of an Agreement for Electric Service following a capacity ramp period if new service is requested. The capacity ramp will consist of a four (4) year capacity ramp of 20% annual increments of installed capacity, starting with a year 1 minimum of 20% of installed capacity. At the beginning of year 5 throughout the end of year 14, the capacity will equal 100% of installed capacity. The contract term shall apply irrespective of generation supplier. At the conclusion of the capacity ramp period plus ten years, the contract will automatically renew for additional one-year terms. The Company or the Customer may terminate service under this Schedule by providing the other party with written notice of termination at least sixty (60) days prior to the end of the then current term.

TERMS AND CONDITIONS

XXVII. SPECIAL TERMS AND CONDITIONS FOR HIGH LOAD CUSTOMERS

A. APPLICABILITY

1. Except as modified herein, beginning January 1, 2027, these Special Terms and Conditions apply to a non-residential Customer who (i) elects to receive Electricity Supply Service and Electric Delivery Service from the Company or (ii) who is eligible for and elects to purchase Electricity Supply Service from a Competitive Service Provider in accordance with Va. Code § 56-577 A. with one or more accounts on contiguous property, as described in Section IV.E.1. of these Terms and Conditions, whose (i.) original contracted demand is equal to or exceeds 25 MW, or (ii.) maximum measured demand is equal to or exceeds 25 MW, with such usage occurring for at least three billing months, of the current and previous eleven billing months.

2. A Customer account must receive service pursuant to Schedule 6, 6TS, 10, GS-3, GS-4, GS-5, MBR, or SCR.

B. DEFINITIONS

HIGH LOAD CUSTOMER - a non-residential Customer with one or more accounts on contiguous property as described in Section IV.E.1. of these Terms and Conditions, whose maximum measured demand has reached or exceeded 25 MW during at least three billing months within the current or previous 11 billing months or has a contracted demand of 25MW or more.

ACTUAL MONTHLY LOAD FACTOR is calculated as Monthly kWh divided by the number of Days in the Billing Month divided by 24 divided by the Maximum Measured kW of Demand.

EXPECTED MONTHLY LOAD FACTOR will be determined by the Company based on information provided by the Customer in its load letter.

TERMS AND CONDITIONS

XXVII. SPECIAL TERMS AND CONDITIONS FOR HIGH LOAD CUSTOMERS (Continued)

C. CONTRACT DEMAND

High Load Customers shall have minimum demand requirements as described in the Customer's applicable Rate Schedule. Such contracted demands will be as specified in the Customer's ESA.

D. COLLATERAL REQUIREMENTS

1. For any new service connection occurring on and after January 1, 2027, even if the Agreement for Electric Service ("ESA") was executed prior to this date, the High Load Customer must provide to the Company, as further detailed below, collateral in the amount of $1.5 million per megawatt (MW) of contracted for capacity ("Collateral Requirement"). However, a High Load Customer that (i) maintains a credit rating of at least BBB- from S&P and Baa3 from Moody's, (ii) provides a Parental Guaranty (as defined below), or (iii) maintains liquidity, as calculated in a commercially reasonable manner at the discretion of the Company and as evidenced by providing quarterly financial statements and certification ("Liquidity"), greater than 10 times the Collateral Requirement shall be exempt of 70% of the Collateral Requirement.

2. Collateral Requirement must be provided in one or more of the following forms:

   a. A guarantee ("Parental Guaranty") from the ultimate parent or a corporate affiliate of the High Load Customer for the Collateral Requirement, so long as the guarantor has (i) a credit rating of at least BBB- from S&P and Baa3 from Moody's or (ii) Liquidity greater than 10 times the Collateral Requirement. The Parental Guaranty must be in a format acceptable to and approved by the Company; or

TERMS AND CONDITIONS

XXVII. SPECIAL TERMS AND CONDITIONS FOR HIGH LOAD CUSTOMERS (Continued)

b. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the High Load Customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Presentment of the Letter of Credit must be within the U.S. Such security must be issued for a minimum term of 360 days. The High Load Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 60 days prior to each expiration date f the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. A surety bond ("Surety Bond") for the full Collateral Requirement. The Surety Bond must be issued by a U.S.-based bond issuer with a rating category of Excellent or Superior by AMBest's Credit Rating Service. The cover amount for the Surety Bond must be within the US Treasury's underwriting limit for that issuer. The Surety Bond must be in a format acceptable to and approved by the Company; or

d. Cash for the full Collateral Requirement.

3. Material Adverse Change

   In the event that a High Load Customer or its guarantor experience a material adverse change in its financial profile, in the sole judgement of the Company, including a downgrade at S&P or Moody's, which would change the way in which it has satisfied Collateral Requirements as outlined in (a) through (c) above, the Company may require an alternative form of collateral for the full Collateral Requirement.

4. Failure to comply with Collateral Requirements at the time of connection, or at any point thereafter, shall subject Customer to disconnection of services in accordance with Section XVI.A.2 – Discontinuance of Electric Service, of the Company's Terms and Conditions.

TERMS AND CONDITIONS

XXVII. SPECIAL TERMS AND CONDITIONS FOR HIGH LOAD CUSTOMERS (Continued)

E. CONTRACT TERM

1. Customer's initial contract term will be made for a period of not less than 14 years. Customer will have the choice of either a 4-year Load Ramp of 20% a year or 100% of capacity at time of connection.

2. A Customer may request a modification of its contract within the initial contract term according to the following:

   a. Upon 36 months notice to the Company, the Customer will have the right to a one-time reduction of its contract demand by up to 20% of the original contract demand. Such reduction can not lead to Customer's contract demand after reduction being less than its maximum measured demand over the 36 month notice period.
   b. Subsequently the Customer can request up to an additional 30% reduction of the original contract demand, for a total reduction of 50% of the original contract demand. The Company will approve this additional reduction to the original contract demand under the following conditions:
      i. Customer must provide a 36-month notice for the additional reduction of contracted demand. This notice will not be concurrent with the notice in XXVII.E.1.
      ii. Customer's contract demand after the reduction is not less than 25 megawatts.
      iii. Another High Load Customer(s), served from the specific infrastructure built to serve the original contracted demand, must be willing to contract for the demand reduction requested by the Customer and assume all terms and charges (excess facilities, contract minimums, etc.) associated with the demand being reassigned.
      iv. Customer's contract demand after reduction can not be less than its maximum measured demand over the 36 month notice period.
      v. All other reassignment provisions pursuant to the Customer's tariff or these Terms and Conditions continue to apply.

3. When a Customer is no longer eligible or willing to take service from the Company within the initial contract term, the Customer shall pay a contract exit fee. The exit fee shall be calculated as the nominal value of the remaining minimum charges for the terminated/reduced capacity determined using applicable rates in effect at the time of the termination/reduction.

Docket No. 4220-TE-119
Witness: Tyrel J. Zich

PROPOSED TARIFF SHEETS

VERY LARGE GENERAL TIME-OF-DAY SERVICE

Availability: This rate schedule is mandatory for any retail customer with transmission interconnection capacity equal to or greater than 100,000 kW.

Kind of Service:

1. Alternating current at the following nominal voltages:
   a. For Transmission Voltage Service-Transformed- i) three-phase at 2,400 volts or higher, with service taken and metered at substation which is fed at 69,000 volts or higher; or ii) three wire three-phase service at 34,500 volts or higher, but less than 69,000 volts.
   b. For Transmission Voltage Service-Untransformed service at 69,000 volts or higher.
2. Service voltage available in any given case is dependent upon voltage and capacity of existing Company lines in vicinity of customer's premises.
3. Transmission Transformed Service under category 1a-i above is available only to customers that take service at the point of metering in a Company substation. All facilities on the load side of the metering (including but not limited to: switches, overcurrent protection, cables, wire and support structures) shall be the responsibility of the customer and subject to engineering plan approval by the Company.
4. Transmission Voltage Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.13.

Rate:

Customer Charge per Month		$4,000	
Demand Charges per Month per Month per kW		June to September	October to May
On-Peak	Transmission Transformed	$42.43	$33.47
	Transmission Untransformed	$37.50	$34.25
Incremental On-Peak			
	Sub-Class 1	$0.00	$0.00
	Sub-Class 2	$0.00	$0.00
Distribution	Transmission Transformed	$0.20	$0.20
	Transmission Untransformed	$0.00	$0.00

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

Energy Charge per kWh	June to September	October to May
On-Peak	3.7470 ¢	3.0746 ¢
Off-Peak	1.9996 ¢	1.8595 ¢

Energy Charge Discount (before Energy Cost Adjustment)
Transmission Untransformed 0.5%

Energy Cost Adjustment: Bills are subject to the adjustment provided in Energy Cost Adjustment. See Schedule X-1, Sheet No. E63.

Definition of Peak Periods: Unless otherwise specified in writing by the Company to any customer using this schedule and refiling this rate sheet not later than November 1 of each year, on-peak hours shall be from 9:00 a.m. to 9:00 p.m. Monday through Friday, inclusive (excluding holidays), for the 12 months beginning with the first full billing period following December 15. The holidays designated shall be New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas, on the day nationally designated to be celebrated as such. When a designated holiday occurs on Saturday, the preceding Friday will be considered an off-peak day. When a designated holiday occurs on Sunday, the following Monday will be considered an off-peak day. Off-peak hours are times not specified as on-peak hours.

Determination of Billing Demand: The billing demand in kilowatts shall be a 15-minute measured demand, adjusted for power factor when applicable, rounded to the nearest whole kW. The customer shall take and use power in such a manner that the power factor shall be as near 100% as possible. In no event shall customer take power in such a manner as to cause leading reactive kilovolt-amperes during the off-peak period.

Current Month On-Peak Period Demand: On-peak period billing demand shall be the greatest 15-minute load within the current billing month, adjusted for power factor, which occurs during any on-peak hours.

Power Factor Adjustment for On-Peak Period Demand: When the average on-peak power factor is less than 90%, the on-peak billing demand shall be determined by multiplying the greatest 15-minute load during the on-peak period by 90% and dividing the product thus obtained by the average on-peak power factor expressed in percent.

The average on-peak power factor is defined to be the quotient obtained by dividing the on-peak kilowatt-hours delivered during the month by the square root of the sum of the squares of the on-peak kilowatt-hours delivered and the lagging reactive kilovolt-ampere-hours supplied during the same on-peak period. Any leading kilovolt-ampere-hours supplied during the on-peak period will not be considered in determining the average power factor.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

Distribution Demand Charge: The distribution billing demand shall be the customer's greatest 15-minute load, regardless of time-of-day and not adjusted for power factor, which occurred during the past 12 months, including the current month.

Incremental On-Peak Demand Charge: Measured as Current Month On-Peak Period Demand. Customer shall be assigned to one specific Sub-Class rate as approved by the Commission.

Late Payment Charge: A one percent (1%) per month late payment charge will be applied to outstanding charges remaining after the payment due date. The Late Payment Charge will be assessed as provided in the Company's General Rules and Regulations, Section 3.6.

Terms and Conditions of Service:

1. Application for Service: Consistent with Section 2.1 of the Company's Rules and Regulations, a customer must make an Application for Service. Such Application for Service shall be made prior to the Company commencing engineering reviews and studies necessary for determining service feasibility and shall include payment of $120,000 to the Company.

2. Customer Load Forecast: Customer will provide Company an estimated, non-binding, and confidential Customer Load Forecast consisting of five (5) years of expected monthly on-peak and off-peak energy, and monthly on-peak demand. Customer shall provide such forecast on January 1st and June 1st of each year following Company's acceptance of customer's Application for Service, and as may be requested no more frequently than twice per year by Company within 30 days of such request.

3. Customer Load Ramp: The Company and customer must agree to a Load Ramp, Load Ramp Start Date, and Contract Capacity for each month of the Load Ramp Period. The Load Ramp Period shall not exceed five (5) years of the 15-year Initial Term.

4. Effective Date: This Tariff shall apply the earlier of the date customer executes a Transmission Interconnection Agreement (IA) or such other date as the parties may agree to in writing.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

5. Term: The Initial Term of service shall be fifteen (15) years following the date when the Company's facilities achieve the technical requirements for energization pursuant to the terms of the IA, but in no event earlier than customer's Load Ramp Start Date. The Load Ramp Start Date may be extended on a day-for-day basis resulting from Company's delay in achieving the technical requirements for energization as set forth in the IA. Upon expiration of the Initial Term, service shall be automatically extended for successive five-year periods thereafter (Extended Terms) unless terminated by the customer. Customer shall provide no less than twenty-four (24) months' notice of intent not to renew prior to the end of the Initial Term or any Extended Term.

6. Contract Capacity: Contract Capacity means the customer's maximum monthly demand as measured in kW estimated by the customer in their Application for Service ("Maximum Contract Capacity"), subject to modification at customer request until the Effective Date. Contract Capacity increases and reductions following the Effective Date are subject to the following provisions:

    a. Contract Capacity Increases: The Contract Capacity may be increased, subject to generation and transmission capacity availability as determined at the sole discretion of the Company. If additional capacity is required, the customer must make an Application for Service under Section 1. Additionally, Company and customer will meet and confer regarding an increase to the Contract Capacity if the Customer Load Forecast of monthly on peak demand provided pursuant to Section 2 exceeds the Contract Capacity. Customer's service shall be limited to the Contract Capacity, except during the Load Ramp Period where customer's monthly on-peak demand may exceed the Contract Capacity by no more than 10,000 kW. At no time may customer's monthly on-peak demand exceed the Maximum Contract Capacity.

    b. Contract Capacity Reductions: Customer may reduce the Contract Capacity by providing no less than twenty-four (24) months' written notice to the Company (Capacity Reduction Notice) and paying the Contract Capacity Reduction Payment and any other amounts due and owing by customer, upon the occurrence of the latter of twenty-four (24) months after the date of the Capacity Reduction Notice or the Capacity Reduction effective date. A reduction of Contract Capacity by customer to zero shall operate as customer termination under this Tariff.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

c. Contract Capacity Reduction Payment: In addition to payment of any revenue or other fees that may be due and owing by the customer, customer shall pay the Contract Capacity Reduction Payment which is equal to the difference between the Contract Capacity and the revised contract capacity as set forth in the Capacity Reduction Notice, multiplied by (a) the sum of the applicable on-peak demand changes multiplied by seventy-five percent (75%) and the applicable incremental on-peak demand charges multiplied by one-hundred percent (100%), multiplied by (b) the lesser of the number of months remaining in the Initial or Extended Term or ninety-six (96) months. If the capacity reduction occurs prior to energization pursuant to the terms of the IA, the difference between the Contract Capacity and the revised contract capacity shall be calculated from the start of the Load Ramp Period for a period of ninety-six (96) months. If the capacity reduction occurs during the Load Ramp Period, the difference between the Contract Capacity and the revised contract capacity shall be calculated starting from the month following the twenty-four (24) month Capacity Reduction Notice for a period of ninety-six (96) months. No Contract Capacity Reduction Payment is due in the event of customer providing timely notice of intent not to renew the Initial Term or any Extended Term.

d. Contract Capacity Reduction Payment Mitigation: The Company and customer will meet and confer following a Capacity Reduction Notice and during such period, the Company will use commercially reasonable efforts to mitigate costs, damages, and charges, including reallocation of contract capacity. The Company will make a Contract Capacity Reduction Payment Mitigation filing with Commission no later than twenty-four (24) months after receiving a Capacity Reduction Notice. The filing will address the mitigation process and timeline for potential repayment of all or a portion of any customer Contract Capacity Reduction Payment.

e. Customer Reallocation of Contract Capacity: The Company and customer will meet and confer regarding a request to reallocate all or a portion of the Contract Capacity to serve another customer. The Contract Capacity Reduction Payment does not apply to Contract Capacity that is reallocated to other retail customers in the Company's Wisconsin service territory. The applicability of the Contract Capacity Reduction Payment is subject to Company and Commission approval when Contract Capacity is otherwise reallocated. No Contract Capacity shall be assigned or transferred without the written consent of the Company, and any assignee or transferee must meet the Credit Support requirements in Section 8.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

7. Minimum Monthly Bill: Upon Company facilities achieving the technical requirements for energization pursuant to the terms of the IA, and beginning no later than the Load Ramp Start Date, the customer shall pay an amount equal to the greater of (a) actual on-peak monthly demand to be billed, or (b) seventy-five percent (75%) of the Contract Capacity multiplied by the applicable on-peak monthly demand charges, plus one-hundred percent (100%) of the effective customer charge, plus one-hundred percent (100%) of the Contract Capacity multiplied by the applicable incremental on-peak demand charge.

8. Credit Support: Customer shall provide credit support at its sole cost and expense in favor of Company and shall maintain such credit support while receiving service from the Company consistent with the terms and conditions set forth below, in one or more of the following forms:

   a. Subject to Company's sole and absolute discretion, customer shall deliver within 30 days following Effective Date and thereafter maintain during the Initial and Extended Terms, a guaranty substantially in the form proposed by Company, from a parent or other guarantor ("Guarantor") equal to the Minimum Monthly Bill at the Maximum Contract Capacity multiplied by the remaining number of months of the Initial or Extended Term ("Guaranty").

      i. A Guarantor must have a minimum tangible net worth of at least $500,000,000, an Investment Grade Credit Rating (and if such Credit Rating is exactly equivalent to BBB- (S&P) / Baa3 (Moody's), and must not be on credit watch by any rating agency) ("Qualified Entity"). If the Credit Rating of the Guarantor is downgraded below Investment Grade, put on credit watch, or an event occurs that (in the reasonable determination of Company) will have a negative impact in the creditworthiness of the Guarantor, then Company may require the Guarantor to convert the guaranty to a security fund instrument meeting the criteria set forth in Section 8(d) below no later than 30 days after notice from Company.

   b. In addition to the Guaranty, Customer shall deliver 30 days prior to the Load Ramp Start Date and thereafter maintain during the Initial and Extended Terms, upon terms satisfactory to the Company, (i) a cash deposit or (ii) a letter of credit in an amount equal to the Minimum Monthly Bill at the Maximum Contract Capacity multiplied by three (3), subject to any adjustments as may be implemented through revisions to the tariffed rates.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

c. In the event that a customer is unable to provide the requisite Guaranty, then customer shall provide the requisite cash or letter of credit under Section 8(b) within 30 days after the Effective Date calculated based on the lesser of (i) the number of months remaining in the Initial Term or Extended Term or (ii) three (3) years, but in any case no less than three (3) months. The credit support is subject to modification to reduce the total amount proportionally to the amounts paid during the Initial Term on an annual basis beginning on the tenth (10th) anniversary of the Effective Date.

d. Upon the occurrence and duration of a Credit Event, within 30 days of demand from Company to customer, Guarantor shall provide to Company either (i) a cash deposit, (ii) a letter of credit, or (iii) other credit support in a form and from and entity reasonably acceptable to the Company, in the amount of Company's credit exposure over remaining Initial or Extended Term, which credit support shall not exceed the Guaranty.

   i. Credit Event. One of the following: (i) that Guarantor's minimum tangible net worth is less than $500,000,000; (ii) Guarantor's credit rating is not equal to or better than BBB- from S&P or Baa3 from Moody's; (iii) customer has declared bankruptcy or has otherwise become insolvent; or (iv) in the event of an uncured customer default.

e. Sections 2.3 and 2.4 of the Company's Rules and Regulations do not apply to this Tariff.

9. Extensions Involving Substation and Transmission Facilities: Customer is required to contribute one hundred percent (100%) of Company's substation and transmission facility costs necessary to directly accommodate customer's requirements prior to energization. Section 5.2 of the Company's Rules and Regulations does not apply to this Tariff.

10. Large Energy Customer: A customer taking service under this Tariff voluntarily and permanently waives and disclaims any right to petition the Commission for a determination that the customer is a Large Energy Customer under the current version of Wis. Stat. 196.374(5)(b), under any amendments to this statute in the future, or any current or future equivalent or materially similar statute. As a condition of receiving service under this Tariff, the customer voluntarily waives the ability to receive grants and benefits in an amount equal to the contributions from their customer class.

11. Interruptible Load: A new customer may nominate all or a portion of their Contract Capacity as interruptible in their Application for Service in Section 1. An existing customer may nominate a portion of their Contract Capacity as interruptible providing no less than twenty-four (24) months' written notice to the Company and Contract Capacity Reduction Payments may apply subject to final terms and conditions. Terms and conditions and interruptible bill credits are subject to Company and Commission approval prior to becoming effective.

(Continued)

VERY LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

12. Innovative Resources: Customer and Company may agree to innovative alternatives, for example generation, energy storage, transmission, and distributed energy resources, where the benefits and costs are assigned to the customer. Terms and conditions and rates are subject to Company and Commission approval prior to becoming effective without harming the Company and non-participating customers.

13. Standby, Maintenance, and Supplemental Services. Customers with generation interconnected to the Company's system in accordance with the Company's General Rules for Parallel Generation may request Standby, Maintenance, or Supplemental Services as defined on the Pg-4 tariff. Terms and conditions and rates are subject to Company and Commission approval prior to becoming effective.

14. Customer may be served through multiple transmission voltage services with multiple metering points at the same site. The peak demands associated with each transmission voltage metering point at the single customer site will be totalized for billing and tariff availability purposes, subject to Company approval.

15. Itemized bills for electric service shall be prepared by the Company on a calendar month basis.

16. Where there is any conflict between this Tariff and the Company's Rules and Regulations, the terms of this Tariff will control.

Rate Codes:

B## Very Large General Time-of-Day Service

Rate Code Cross Reference

Rate Schedule	**CSS Code**	
Controlled Water Heating Service – Res/Comm (Closed)	B37 (Closed)	
UG Area Lighting Service (Ms-6) – Private	B38	
Company Owned LED Street Lighting (Ms-3) - OH	B39	
Company Owned LED Street Lighting (Ms-3) - UG	B40	
Customer Owned LED (Ms-3.1)	B41	
Underground Area Lighting Service (LED) Public (Ms-6)	B42	
Underground Area Lighting Service (LED) Private (Ms-6)	B43	
Automatic Protective Lighting Service (LED) (S-1)	B44	
Military Facility Distribution Service (Ds-1)	B45	
Very Large General Time-of-Day Service (Cg-13)	B##	N
Experimental Real Time Pricing (RTP-1)	B60	

EXPERIMENTAL MARKET-BASED PRICING SERVICE

Availability: Available to customers who establish a contract with Company that includes market-based pricing and service conditions that comply with Wis. Stat. § 196.192(2)(b). Customers requesting this service must provide a proposal to Company that includes an economic analysis which demonstrates that the proposed service contract has merit and will not harm other customers or shareholders of Company.

Purpose: This service is intended to allow Customer to receive market benefits and take market risks for Customer's electricity purchases from, or sales to Company. Company is under no obligation either to take market price risks associated with Customer's proposal or to assure that Customer realizes market price benefits.

Terms and Conditions:

1. Customer is subject to all terms of Company electric service schedules and riders except as specifically modified by a contract for this service.

2. Customer and Company must agree and document all provisions for this service in a written contract. All initial contracts and contract amendments must be filed with and approved by the Public Service Commission of Wisconsin.

3. The contract term must be specified. Unless otherwise specified, the default contract term is 12 months from date of signing.

4. Company must respond within thirty days of the initial receipt of Customer's proposal for a market-based pricing agreement. Customer has the burden of developing a feasible and practical proposal, including all necessary supporting analyses that are required by Company. The proposal must include justification of the market-based pricing as defined in Wis. Stat. § 196.192.

5. Company's rejection of Customer's proposal must be accompanied by either a description identifying problems with the proposal or a counter proposal. Reasons for rejection could include but are not limited to the following: a) The proposal, if accepted, will harm other customers of the Company who are not subject to the service; b) The proposal, if accepted, will harm the shareholders of the Company; or 3) The proposal, if accepted, would not subject the customer to market risks as defined in Wis. Stat. § 196.192(2)(b).

6. Company is under no obligation to expend unreasonable time or resources on an analysis of a Customer's proposal, or to agree to any Customer proposal.

~~6.~~7. This service is not available to customers that are eligible for the Cg-13 tariff. N

RULES AND REGULATIONS

Section 1.0 Customer Classification

1.1 Residential Customer

A residential customer is one using single-phase electric service for general household purposes in space occupied as living quarters, such as a single private residence, mobile home, apartment unit, fraternity house, sorority house, rooming house, and a trailer on a permanent foundation.

In cases of residential and general service usage in a single premise served through a single meter, the rate applying to the predominate use (as determined by the Company) will govern the selection of the rate which shall apply.

1.2 Farm Customer

A farm customer is one using single-phase or three-phase electric service for the production of income from agricultural pursuits such as gardening, dairying, egg production, or the raising of crops, livestock or poultry. A farm customer may combine his general household use of electric service, if any, with his farm operating use through one meter. However, where a customer uses electric service for general household purposes and his agricultural pursuits are minor and the farm operating equipment total is not more than one kilowatt of connected load, such customer shall be classified as residential. Where electric equipment is used jointly for general household and farm operating purposes (such as a water pump), the major use of such equipment will determine whether it be classified as being for general household or farm operating purposes.

1.3 General Service~~, and~~ Large General Service, and Very Large General Service Customer R

A general service, ~~or~~ large general service, or very large general service customer is one using electric service for commercial purposes, such as a store, office, shop, hotel, apartment hotel or multiple apartments, wholesale house, warehouse, garage, and filling station, or for the production of commerce through manufacturing, processing, refining, mining, and fabricating or for a pumping plant, railroad shop, laundry, printing plant, grain elevator, and stockyard. A school, church, hospital, post office, courthouse, municipal building, and an institution of a similar nature will be classified as a general service, large general service, ~~-~~or very large ~~power~~ general service customer. R R R

In cases of residential and general service usage in a single premise served through a single meter, the rate applying to the predominate use (as determined by the Company) will govern the selection of the rate which shall apply.

1.4 Curtailable Customer

A curtailable customer is a customer who agrees to curtail electric service when requested to do so by the Company.

P.S.C. W.VA. TARIFF NO. 16 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 21 (WHEELING POWER COMPANY)

(SCHEDULE L.C.P.
(Large Capacity Power Service)

AVAILABILITY OF SERVICE

Available for general service to customers. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet maximum requirements, but in no case shall the contract capacity be less than 1,000 kW.

MONTHLY RATE

Schedule Codes	Service Voltage	Demand Charge ($/KW)	Off-Peak Excess Demand Charge ($/KW)	Energy Charge (¢/KWH)	Customer Charge ($/Month)
386	Secondary	(I)21.00	(I)3.71	(I)0.789	(I)90.92
387	Primary	(I)17.42	(I)2.10	(I)0.768	(I)294.15
388	Subtransmission	(I)12.64	(I)1.70	(I)0.763	(I)401.12
389	Transmission	(I)12.09	(I)1.63	(I)0.749	(I)508.08

Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand . . . .(I)$0.75/KVAR

(C) **OTHER CHARGES/CREDITS**

Service under this Schedule may be subject to the C.S. (Original Sheet No. 27), the E.C.S. (Original Sheet No. 27A-1), the E.E./D.R. (Original Sheet No. 33), the B.R.S.P. (Original Sheet No.23), the B.B.S. (Original Sheet No. 30-1), the E.N.G.(Original Sheet No. 49-1), the E.N.E.C. (Original Sheet No. 34), and C.R.R.C. (Original Sheet No. 35) which is embedded in the ENEC rates. Further information can be found at RIDER APPLICABILITY (Original Sheet No. 37).

MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

LOCAL TAX ADJUSTMENT

To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents, of the Company by the "Last Pay Date" shown on the bill shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

(C) Indicates Change, (D) Indicates Decrease, (I) Indicates Increase, (N) Indicates New, (O) Indicates Omission, (T) Indicates Temporary

SCHEDULE L.C.P.
(Large Capacity Power Service)
(continued)

MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

The off-peak excess demand shall be the amount by which the demand created during the off-peak period exceeds the monthly billing demand.

The reactive demand in KVAR shall be taken each month as the single highest 30-minute peak in KVAR as registered during the month by a demand meter or indicator.

Billing demands shall be rounded to the nearest whole KW and KVAR.

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

METERED VOLTAGE ADJUSTMENT

The rates set forth in this Schedule are based upon delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment or the application of multipliers to the metered quantities. In such cases, metered KWH, KW and KVAR will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

(a) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(b) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

TERM

The customer shall contract for a definite amount of electrical capacity in kilowatts sufficient to meet its maximum requirements, but in no event shall the contract capacity be less than 1,000 KW.

Contracts will be required for an initial period of not less than two (2) years and shall remain in effect thereafter until either party shall give the other at least one (1) year's written notice of the intention to discontinue service under this Schedule.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods longer than two (2) years pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

P.S.C. W.VA. TARIFF NO. 16 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 21 (WHEELING POWER COMPANY)

SCHEDULE L.C.P.
(Large Capacity Power Service)
(continued)

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

LARGE LOAD CUSTOMERS

Applicability

The following terms and conditions do not apply to the contracted capacity of any existing customer as of January 1, 2025. After January 1, 2025, the following terms and conditions apply to any new load, and to any expansion of existing load, so long as that new load or load expansion itself has a contract capacity greater than or equal to 100 MW at an individual site or 150 MW on an aggregated basis ("Large Load Customer"). The Company will exercise reasonable discretion when choosing to aggregate premises, with such discretion based on factors including, but not limited to, premises sharing one or more of the following: common owner(s), a common parent company, common local electrical infrastructure, and common control. Large Load Customer's Initial Contract Term, load ramp, Load Ramp Period, contract capacity, and other terms of service under this Tariff will be defined in the Electric Services Agreement(s) ("ESA(s)") executed between the Company and Large Load Customer. Nothing herein shall limit or otherwise affect the ability to file a Special Contract pursuant to Commission Rules, or of either Large Load Customer or the Company to file a formal proceeding requesting the Commission to resolve a dispute regarding the application of this tariff or a Special Contract providing special terms and conditions.

Contract Term

The Large Load Customer's Initial Contract Term will be made for a period of not less than 12 years. A Large Load Customer may designate a Load Ramp Period, which can be no greater than five years. If a Load Ramp Period is designated by the Large Load Customer, the Initial Contract Term shall commence after the Load Ramp Period ends. The Load Ramp Period is the later period of time from when: (a) electric service is available to the Large Load Customer or (b) the Large Load Customer is scheduled to begin taking electric service, until the time the Large Load Customer's maximum contract capacity is billed. The Contract Term is the Load Ramp Period plus the Initial Contract Term.

Monthly Billing Demand

The Monthly Billing Demands for Large Load Customers shall be the single-highest 30-minute integrated peak in kW, as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months. The off-peak excess demand shall be the amount by which the demand created during the off-peak period exceeds the monthly billing demand.

Minimum Charge

The Large Load Customer is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, all applicable adjustments, and the product of the Base Billing Energy and the monthly base energy charge. The Base Billing Energy provision will only apply to base rate energy charges. The Base Billing Energy will be computed as follows: Contract Capacity (kW) * 60% * Number of Billing Hours in the Month.

P.S.C. W.VA. TARIFF NO. 16 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 21 (WHEELING POWER COMPANY)

SCHEDULE L.C.P.
(Large Capacity Power Service) (continued)

Collateral Requirement

The Large Load Customer shall provide collateral in a form acceptable to the Company based upon the creditworthiness of the customer. The amount of collateral provided shall be equal to 24 times the Large Load Customer's previous maximum monthly non-fuel bill. During the first year of the contract, the maximum expected bill for the year shall be used. The amount of collateral to be provided will be recomputed annually, and updated if the recomputed value is 10% greater than the current amount held.

Contract Capacity Reductions

Large Load Customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five years of the Initial Contract Term by up to 20%, in total, by giving the Companies at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought. For the avoidance of doubt, regardless of the number of notices provided, the total capacity reduction under this provision shall not exceed 20%, unless by mutual agreement between the Large Load Customer and the Company, which the Company shall only grant in circumstances that are beneficial, or at least not detrimental, to the Large Load Customer, the Company, and all other customers.

Large Load Customer may terminate its contract or reduce its contract capacity beyond 20% at any time after the first five years of the Initial Contract Term by giving the Company at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought, subject to payment of a capacity reduction/termination fee ("Exit Fee"). The Exit Fee shall be due and payable to the Company upon the effective date of the contract termination or the effective date of the capacity reduction. The Exit Fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining years of the Exit Fee Period, the Exit Fee shall be calculated in the same manner as the first year, minus the Large Load Customer's estimated reduction in allocated PJM LSE OATT transmission charges to the Company on a West Virginia jurisdictional basis. The Exit Fee Period is defined as the Large Load Customer's then remaining Initial Contract Term, or any agreed extension. The Exit Fee Period shall not be less than one year and shall not exceed five years.

Following receipt of proper notice, through the Exit Fee Period, the Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. The remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.

If there is an issue concerning the calculation of the Exit Fee or delivery of any mitigation amounts, that either the Company or Large Load Customer view as in need of escalation, either the Company or Large Load Customer may request escalation. Such request shall be made in writing and within 14 business days of the Large Load Customer being notified regarding the Exit Fee calculation. In such instance, management representatives for the Company and for the Large Load Customer will discuss and seek to resolve any issues. The management discussion shall occur within 14 business days of a request, unless otherwise agreed to in writing by the Company and Large Load Customer. The Company and Large Load Customer agree to use this escalation process in good faith, escalating only those matters appropriate for management's consideration. This dispute resolution process does not limit or otherwise affect the ability of either Large Load Customer or the Company to file a formal proceeding requesting the Commission to resolve the dispute.

Large Load Customer shall not assign any of its rights or delegate any of its obligations under the Contract without the written consent of the Company. An assignment or delegation in violation of this Paragraph is null and void.