MARYLAND PUBLIC SERVICE COMMISSION

Report on Co-Location

Submitted to the Senate Committee on Education, Energy, and the Environment and the House Economic Matters Committee
Annapolis, Maryland
Pursuant to Senate Bill 1 (SB1)/Chapter 537, Section 6, 2024

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Senate Bill 1 – Report on Co-Location

Executive Summary

Pursuant to Senate Bill 1 (SB1)/Chapter 537 of 2024, the Maryland Public Service Commission (Commission) is required to study and make recommendations to the Senate Committee on Education, Energy, and the Environment and the House Economic Matters Committee on "issues related to the utilization of end-use electricity customer load that is physically connected to the facilities of an existing or planned electric generation facility, also known as co-located load configuration."

In this report the Commission is required to address findings on:

1. Potential cost impacts to Maryland ratepayers;
2. Potential impacts to wholesale markets (capacity, energy, and ancillary) and planning functions;
3. Potential impacts to the reliability of the electric transmission and distribution systems serving Maryland; and
4. Means to manage or mitigate any of these impacts.

The impacts of co-locating load with generation vary with the type of arrangement being considered and on a case-by-case basis. Some possible co-location configurations may bring reliability and cost benefits, while others, depending on how they are addressed, may bring challenges to the grid and to ratepayer equity.

Co-location, namely, the physical siting and direct physical connection of end-use load with generation, is not itself a novel concept. This report focuses on an emerging co-location arrangement in which a load co-locates with an existing generator that is interconnected to the grid but is situated behind the generator's meter. The Commission makes the following observations.

Potential Impacts to Reliability

Co-location of significant new quantities of load with existing baseload generation could present significant risks to reliability in Maryland and the PJM region. This is particularly true of co-location arrangements where "not-network load" connects behind the generator's meter and can be considered off-system, which PJM has indicated it would not include in portions of its planning process. (This co-location arrangement is described in detail below.) If not-network load co-locates with baseload generation, such as the Calvert Cliffs nuclear plant, significant quantities of existing capacity will be effectively removed from the grid and resource adequacy may be degraded at an accelerated pace relative to connecting such load in traditional ways. Baseload capacity of the type Calvert Cliffs provides could take years to plan, certificate, and build.

In addition to being costly to replace a large nuclear plant, the quality of the generation—including the very high capacity factor of Calvert Cliffs—would be difficult to replace. The highly reliable and continuous operation of these large baseload facilities is part of the appeal of co-locating there in the first place.

Generally, any large load connecting to the grid without the addition of new generation can contribute to reliability concerns, especially in the context of a resource-constrained grid. The policy goal of increased electrification of sectors of the economy, as well as the addition of large loads such as data centers, present challenges to the overall resource capacity of the grid.

Impacts to reliability from co-location are somewhat situationally specific and certain arrangements have the potential to offer certain reliability benefits on the grid. Benefits could include increased optionality for flexibility and reduced transmission losses.

Potential Impacts to Wholesale Markets, Planning Functions, and Ratepayers

During the Commission’s September 24, 2024 Technical Conference on co-location, discussed below, the Commission received testimony on the potential impact to the customers of Maryland’s local utilities.

From a market price perspective, as indicated by PJM’s independent market monitor (IMM), the impacts of a load co-locating with generation (regardless of whether this co-located load is “not-network”) may be comparable to those of any large load connecting to the grid, all else equal. This analysis appears reasonable; in either case, to maintain resource adequacy, PJM may need to incent new generation (either to replace lost generation in a not-network scenario or to supply new demand with new generation) in its markets. Without the simultaneous addition of generation, the impact of a large load joining the grid may be an increase in the marginal price of electricity because demand on the grid is being increased without simultaneously increasing supply.

However, the cost impacts of large load co-locating in a not-network configuration with existing generation have the potential to be more consequential than the impacts associated with load connecting to the grid in a traditional manner. This form of co-location could accelerate the pace at which large loads can be brought online and thereby more quickly diminish resource adequacy —a key component in maintaining grid reliability. This would exacerbate market impacts of the load joining the grid and increase costs to ratepayers. In fact, the cost effect on ratepayers could be acute if resource adequacy on the grid is strained to begin with. Additionally, not-network co-located entities could avoid participating in the payment of the costs they cause in the markets and some costs which they cause by creating the need for grid upgrades. If not-network co-location occurs with existing generation, reliability issues that the entities in this configuration cause may need to be addressed after the fact through transmission and/or new generation solutions that could take years to build.[1]

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[1] During the Commission’s Technical Conference, conflicting views were presented about the ability of PJM and transmission owners to study the impacts of not-network co-located load, with some arguing that the study process for not-network load would be diminished in comparison to the studies required for network load. Overall, the Commission believes that PJM has an opportunity to perform reliability studies for a load joining the grid in all circumstances, co-located or not. However, there is no standardized study process for not-network co-location in PJM's tariff, making it unclear whether a transmission owner would always be included in the study process for not-network co-location and whether reliability examination would be comprehensive.

Means to Manage or Mitigate Potential Impacts

Nationwide, state public utility commissions and the Federal Energy Regulatory Commission (FERC) are analyzing the jurisdictional issues surrounding the co-location of large load with generation. FERC's technical conference and related proceedings addressing co-location are described further below and relate to cost allocation at the wholesale level.

At the State level, the Commission recommends that the Maryland General Assembly clarify that co-located load is retail load. Confirmation that the definition of "retail electric customer" (as specified in the Public Utilities Article (PUA) of the Maryland Code) applies to co-located loads would clarify the Commission's authority to regulate cost allocation for these loads by imposing on a co-located load the costs it imposes on the grid, commensurate with principles of cost causation. It is also recommended that the legislature clarify the definition of an electric company and/or electricity supplier as it may apply to the generator supplying and/or delivering power to the load in the case of co-location and to specifically clarify whether the electric company through which tariffs can be assigned is the utility in whose territory the load is physically located. It is also recommended that the State revise the PUA to make clear whether or not co-located load must meet the requirements of Maryland's renewable portfolio standard (RPS), pay for offshore wind renewable energy credits (ORECs), and make other payments to cover State programs such as EmPOWER, regardless of retail load designation by the legislature.

Regardless of the timing of related pending cases at FERC addressing co-location, the General Assembly may also consider establishing a State agency review process for co-location configurations. The review process could undertake an analysis of all factors related to the benefits and costs to the State of the proposed co-location arrangements. Such a process could allow for determination as to whether each proposed co-location instance is in the public interest before it is allowed to proceed.

Finally, the Commission notes that, should new large loads bring new generation with them, along with back up generation, resource adequacy challenges could be ameliorated. While large load developments are often integral participants in the modern economy with the expectation of employment and local tax revenue, such facilities, and data centers in particular, require significant resources that impact existing residents and businesses. The anticipated load on the local electric utility without new generation additions could affect reliability and prices for current ratepayers.

Elected representatives, in coordination with State and local governments and in conjunction with data center developers, should develop and enact policies to ensure that the new economic opportunities of these facilities are balanced with the impacts of their locations throughout the State. The Commission is prepared to address the integration of data centers within the service territories of the utilities in Maryland under the authority granted by the Public Utilities Article.

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1. Background

1.1 Commission Requirements and Process

Senate Bill 1 (SB1)/Chapter 537 of 2024 requires the Maryland Public Service Commission (Commission) to study and make recommendations by December 15, 2024 to the Senate Committee on Education, Energy, and the Environment and the House Economic Matters Committee on "issues related to the utilization of end-use electricity customer load that is physically connected to the facilities of an existing or planned electric generation facility, also known as co-located load configuration."[2]

In its report to the Senate Committee, the Commission must address findings on:

1. Potential cost impacts to Maryland ratepayers;
2. Potential impacts to PJM[3] wholesale markets (capacity, energy, and ancillary) and planning functions;
3. Potential impacts to the reliability of the electric transmission and distribution systems serving Maryland; and
4. Means to manage or mitigate any of these impacts.

In addition to SB1's mandates, Senate President Bill Ferguson requested that the Commission include within the scope of its report an evaluation of impacts and mitigating factors if an equal amount of end-use customer load instead (a) connects to the transmission or distribution system or (b) chooses to locate in a neighboring state.[4] Impacts in this report are largely discussed relative to scenario (a). Comparison to scenario (b) is discussed in Section 2.2.2.

On June 21, 2024, the Commission provided notice of a public conference (PC 61) to address these topics and requested comments. An extension of the comment submission deadline, from

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[2] Electricity and Gas – Retail Supply – Regulation and Consumer Protection, Maryland Senate Bill 1 §6 (2024). https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/SB0001?ys=2024RS.

[3] PJM Interconnection is the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in Maryland and surrounding states.

[4] Comment filed in the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61 ("PC 61"), Senate President William C. Ferguson IV, Jul. 9, 2024. https://webpscxb.psc.state.md.us/DMS/pc/pc61.

July 12, 2024, to July 26, 2024, was granted on July 9, 2024. The pre-conference public comment period ran until July 26.

On Tuesday, September 24, 2024, the Commission conducted a Technical Conference to engage with stakeholders to further inform this report. The Commission invited interested persons to file any additional comments by October 16, 2024.

In addition to the Commission's proceedings on co-location, this report was informed by examining the record in several Federal Energy Regulatory Commission (FERC) proceedings.[5]

1.2 Co-Location Overview

As defined in SB1, co-located load is "end-use electricity customer load that is physically connected to the facilities of an existing or planned electric generation facility."

This definition encompasses a wide range of possible configurations, including, for example, a combined heat and power plant providing steam heating and electricity to a university or industrial campus, or behind-the-meter (BTM), distributed energy resources (DERs) like rooftop solar on homes. These co-location arrangements have existing policies and regulatory approaches associated with them and are not the focus of this report.

This report focuses on an emerging co-location arrangement in which a load co-locates with a generator that is interconnected to the grid, but is situated behind the generator's meter. Under this arrangement, a load (likely a large load such as a data center, crypto mining facility, or hydrogen producer) would set up its facilities to offtake electricity directly from the generator instead of interconnecting directly with the electric grid. In this scenario, some or all of the generator's capacity could be reserved for the exclusive use of the co-located load, in which case it would not be considered available to serve the wider electric grid. This arrangement was the focus of discussion among stakeholders at the Technical Conference on September 24, 2024.

1.2.1 Defining Terminology

There are two main approaches to co-locating load with wholesale generation that are being raised in related ongoing debates and the details of these are described below.

The first approach is to treat the load as PJM Network load. Load has traditionally been added to the PJM electric grid as Network load. Network load interconnects to the grid and receives transmission service from a transmission provider. As such, the transmission system is planned to serve this load[6] and applicable costs related to serving the load are allocated roughly commensurate with the benefits received from the grid. This type of co-location will be referred to as **"Type A"** co-location throughout this report.

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[5] Documents reviewed were filed in FERC Docket No.'s AD24-11-000, ER24-2172-001, ER24-2888, ER24-2889, ER24-2890, ER24-2891, ER24-2893, ER24-2894, EL24-149, and EL25-20.

[6] The Definition of "Network Load" in PJM's tariff is "the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III." PJM Interconnection, L.L.C., Open Access Transmission Tariff (OATT), §1, Docket No. ER24-1987-000 (May 31, 2024). https://pjm.com/directory/merged-tariffs/oatt.pdf.

"Not-network" load is a concept discussed in the PJM guidance document on co-location.[7] This concept refers to load that is not designated as PJM Network load and can be considered "off system"[8] and is served exclusively by co-located generation. PJM guidance indicates that this type of co-located load must have protective equipment in place to prevent the co-located load from drawing power from anywhere on the grid besides the generator with which it is co-located. PJM has indicated that it will not include co-located load under this arrangement in its load forecasts and would not account for this load in its "holistic" planning processes.[9]

"Not-network" co-location is a novel configuration in the PJM region. While it is discussed in PJM guidance on co-location, it does not exist in PJM's FERC-approved operating agreement or tariff (i.e., governance documents addressing such things as PJM's wholesale markets and transmission.) Only one known co-located arrangement of this type exists in the PJM region at the time of this report (at the Susquehanna Steam Electric Station, a nuclear plant in Pennsylvania) and for a limited amount of capacity.[10] This type of co-location will be referred to as **"Type B"** co-location throughout this report.

1.2.2 Motivations for Co-Location

There are various reasons why commercial interests in the load and generation business may wish to co-locate. These may include but are not limited to timing, cost, and access to carbon-free resources. Co-location may also bring economic benefits to the State in the form of jobs and tax base and could have some reliability benefit in the forms of proximity and flexibility.

Timing Considerations

Entities have cited the possibility of enabling power delivery to loads on a shorter timescale as a key reason for pursuing co-location.[11] Timing relates to two parts of the process of a load coming online through co-location. First, there is the consideration of generation availability. Co-locating with existing generation is one method of potentially securing a dedicated, preferred source of power more quickly than if a load waited to purchase power from planned, new-build generation. There are multi-year wait times associated with new generation clearing the interconnection queue in the PJM region and large plants appear to be taking longer to build than they have historically.[12]

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[7] PJM Interconnection, L.L.C., Guidance on Co-Located Load (Mar. 22, 2024, updated Apr. 17, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/pjm-guidance-on-co-located-load.ashx.

[8] Statement of Frederick S. "Stu" Bresler on Behalf of PJM Interconnection, L.L.C. in Docket No. AD24-11-000. https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20241104-4013.

[9] *Id.*

[10] Co-location was first requested at the site through FERC Docket No. ER23-1043-000. https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20230203-5017. *See* Appendix B.

[11] Mr. George representing Google, FERC Docket No. AD24-11-000 Hr'g Tr. at 91-92. *See also* Ms. Phillips representing LS Power Development, FERC Docket No, AD24-11-000 Hr'g Tr. at 80-81. *See also* comments filed in PC 61, Data Center Coalition, Oct. 16, 2024.

[12] *See* Rand, J., Manderlink, N., Gorman, W., Wiser, Seel, J., Mulvaney Kemp, J., Jeong, S., & Kahrl, F. (2024, April). Queued Up: 2024 Edition. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/queued-2024-edition-characteristics. "The median duration from interconnection request (IR) to commercial operations date (COD) continues to rise, approaching 5 years for projects completed in 2022-2023."

Second, the time to study enhancements to the grid to accommodate new load can be lengthy. Stakeholders in several forums have asserted that Type B co-located load could complete this study process and be brought online more quickly than if the load were to connect in the traditional manner as a result of potential differences in the study process.[13] Third, although not specifically identified by stakeholders, news reports of opposition to data centers in Loudon County, Virginia, just outside of Maryland, are ongoing. Prospective large load customers like data centers may prefer to locate at a remote, industrial site to avoid such opposition and bring their facilities online sooner.

Cost Considerations

A generation owner may be motivated to co-locate with large load to the extent that co-location encourages a large customer to enter into a bilateral power purchase agreement (PPA) which can provide price certainty for both the generator and the load.

While it has been represented that the Type B colocation arrangement is not entirely motivated by cost and that speed is the most important factor,[14] load in this arrangement may avoid paying bulk power costs. Cost avoidance and its impacts on ratepayers are discussed in Section 2.3.

Access to Carbon-Free Energy

One of the most discussed co-location configurations is a hyperscaler data center co-locating with an existing commercial nuclear plant, motivated primarily by the high capacity factor of nuclear power relative to other forms of generation and nuclear power's carbon-free capacity.[15]

Proximity and Flexibility

One potential benefit of co-location (regardless of whether it is Type A or Type B) is the possibility of reduction in transmission losses on the grid. Proximity of generation to load reduces the amount of energy lost during delivery. Avoiding this loss precludes the need to install more generating capacity to meet reliability needs. The degree of this benefit relative to not co-locating, however, would be case specific and would depend on how the grid is planned and developed around the co-location.

Also, certain co-location configurations may offer benefits in terms of flexibility. For example, paired with electrolyzers with flexible hydrogen production schedules or with data centers which

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[13] *See*, for example, Mr. Emnett representing Constellation Energy, PC 61 Hr'g Tr. at 278, indicating that Type B co-located load may come online faster than other types of load in part because it would be engaging in a bilateral contract with a generator owner and the two parties would be able to focus on this one contract, unlike in the traditional utility process.

[14] *See*, for example, Mr. George's testimony at FERC on behalf of Google (as cited in footnote 11.)

[15] Securing clean energy is not a motivation for every would-be co-locating load. For example, there is at least one major proposal for data center load to co-locate with a new 3,500 megawatt gas-fired plant in Virginia and another data center co-location proposed with a new 2,200 megawatt gas-fired plant in Louisiana. *See* https://www.power-eng.com/gas/developer-proposes-massive-data-center-campus-with-onsite-gas-turbines-in-virginia/. *See also* https://www.powermag.com/entergy-louisiana-eyes-2-2-gw-of-new-gas-fired-generation-to-support-data-center-demand/.

can vary their demand,[16] such configurations could allow otherwise non-flexible base load generation, like nuclear plants, to rapidly control their effective output to the grid, thereby contributing to grid reliability.[17]

State-Side Motivations: Economic Opportunity

Large loads can be associated with economic growth. Many, including data centers[18] and industrial facilities, can offer jobs and tax revenues to local communities. To the extent that a load might not have connected if it were not for the possibility of co-location, this configuration could bring a degree of economic benefit to the State.

1.2.3 Proceedings at the Federal Level

Because co-location with wholesale generation brings with it novel configurations for grid connection, no clear approaches exist to address any impacts on wholesale electricity delivery or markets. This lack of clarity around this form of co-location has generated multiple filings and protests at FERC. The ongoing debate has spurred FERC to host a technical conference on the topic which was held on November 1, 2024.[19] Entities represented at the conference and involved in the larger conversation around co-location include the North American Electric Reliability Corporation (NERC),[20] PJM, PJM's independent market monitor (Monitoring Analytics, LLC, (IMM)), regional grid planners, independent experts, private generation and large load developers, and state officials.

Outcomes at the federal level could inform how the State may need to proceed to ensure just and reasonable rates at the local level. A summary of various efforts at the federal level may be found in Appendix B.

1.3 Regional Resource Adequacy

Resource adequacy is an important element of reliability that can impact market prices that ultimately affect customers' bills. Achieving resource adequacy entails having sufficient resources to meet demand on the grid, including during extreme weather conditions and other periods of high stress on the grid. PJM's capacity market is designed to retain cost effective generation and attract new generation to build in the region, thereby ensuring resource adequacy.

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[16] Through shifting schedules for tasks which may not be time-sensitive, such as large language model training, for example.

[17] Note that load can contribute flexibility on the grid regardless of whether it is co-located. This could be through participation in demand response programs. PJM has indicated in its guidance (cited in footnote 7) that Type A co-location would be eligible for participation in demand response while Type B co-located load would not be eligible.

[18] Post-Hearing Comments on the Co-Located Load Configuration Study, Technical Staff, PC 61, p. 15.

[19] FERC Commissioner-led Technical Conference Regarding Large Loads Co-Located at Generating Facilities, FERC Docket No. AD24-11-000 (Nov. 1, 2024). https://www.ferc.gov/news-events/events/commissioner-led-technical-conference-regarding-large-loads-co-located.

[20] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC's jurisdiction includes users, owners, and operators of the bulk power system.

Given the current state of the grid and of the market, capacity prices are at a historic high.[21] This is important to note since removing generation capacity from the grid for the purpose of serving a large load without effectively replacing that capacity could challenge resource adequacy and raise prices for existing ratepayers.

2. Potential Impacts of Co-Location

2.1 Reliability

Regardless of whether it is co-located or not, any large load connecting to the grid can contribute to reliability risks.[22] However, it appears that co-location could enable significant quantities of load to join the grid more quickly[23]—potentially more quickly than PJM can effectively plan for—thereby potentially reducing the reserve margin and exacerbating resource adequacy concerns.[24] There are existing concerns that the PJM grid may be resource-constrained in the near future.[25] In Maryland and in the larger PJM region, demand for electricity is poised to increase[26] due to building and transportation electrification and to the deployment of energy-intensive loads like data centers. At the same time, deactivation of historic generating resources is impacting electricity supply. Adding large loads without the simultaneous addition of a corresponding amount of new generation could amplify reliability risk on an already strained grid.

While Type B co-location arrangements could bring reliability benefits, depending on the circumstances,[27] these arrangements could also present some increased reliability risk to the extent that they accelerate degradation of resource adequacy. PJM has developed internal guidelines for reviewing such configurations;[28] however, these guidelines are not FERC-approved standards and they lack transparent and comprehensive bulk power planning

[21] One indicator of resource adequacy is the reserve margin—a measure of the amount of supply that is in excess of forecasted peak demand. In the most recent capacity auction (for the 2025/2026 planning year,) the reserve margin in PJM was 18.5% or 0.7 percentage points higher than the target reserve margin of 17.8%. While the target reserve margin was maintained in this latest auction, this is a significant reduction in the overall reserve margin from the previous auction for the 2024/2025 delivery year and the clearing price increased significantly as a result. 2025-2026-base-residual-auction-report.ashx.

[22] Comments filed in PC 61, ReliabilityFirst Corporation, Jul. 25, 2024 & Sep. 9, 2024. https://webpscxb.psc.state.md.us/DMS/pc/pc61.

[23] *See* footnotes 11 and 13.

[24] Mr. Thiry representing ReliabilityFirst, PC 61 Hr'g Tr. at 24.

[25] "Energy Transition in PJM: Resource Retirements, Replacements & Risks," PJM Interconnection, LLC, Feb. 24, 2023. *See also* footnote 22.

[26] PJM presented its preliminary 2025 Load Forecast on Dec. 9, 2024. https://www.pjm.com/-/media/committees-groups/subcommittees/las/2024/20241209/20241209-item-03---2025-preliminary-pjm-load-forecast.ashx. *See also,* the Electric Power Research Institute has reported that data centers could consume up to 9% of U.S. electricity generation by 2030—more than double the amount currently used. https://www.epri.com/about/media-resources/press-release/q5vU86fr8TKxATfX8IHf1U48Vw4r1DZF.

[27] *See* footnote 22. *See also* statement of Howard Gugel on behalf of NERC in Docket No. AD24-11-000.

[28] For information regarding PJM's efforts to ensure reliability in the Susquehanna ISA, *see* FERC Docket No. ER24-2172-001.

considerations. An examination of transparency and standardization and observations on reliability may be found in Appendix C.

2.2 PJM Wholesale Markets & Planning Functions

SB1 requires the Commission to assess potential impacts to PJM markets (including wholesale capacity, energy, and ancillary services markets) and planning functions. Impacts in the wholesale markets and to regional planning inform cost allocation at the wholesale level which ultimately affects Maryland ratepayers. Details regarding these markets, planning functions, and associated cost allocation impacts may be found in Appendix D.

2.2.1 Wholesale Cost Categories

The following table breaks down the various PJM wholesale costs[33] and the following subsections explain how co-location might impact each category.

Cost Category	Description
Energy	The cost of producing energy to serve load. This cost reflects the availability of transmission capacity to deliver low-cost power to the load's location. If it cannot be delivered, higher cost generation in the vicinity of the load is relied upon to meet demand. Energy is a near-term commodity and is sold in a PJM market.[29]
Capacity	These costs ensure that adequate generation is available in the future to serve demand and ensure resource adequacy in times of need. Effectively, capacity acts as a supply insurance policy for the grid and is sold in a PJM market as mentioned in Section 1.3.[30]
Ancillary Services and Black Start	Ancillary services are mostly market costs associated with balancing load and generation in PJM and with ensuring other real-time grid characteristics necessary for the reliable use of electricity.[31] Black start services are purchased by all transmission customers from PJM to ensure reliable restoration of the grid following a widespread loss of power.[32]
Transmission	Transmission costs are those associated with the delivery of power over the wires and other equipment that comprise the wholesale power grid.

[29] Post-Hearing Comments on the Co-Located Load Configuration Study, Technical Staff, PC 61, pp. 10 - 11.
[30] Capacity Market (RPM), PJM Learning Center, https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx.
[31] Ancillary Service Markets, PJM Learning Center, https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.
[32] "Customer Guide to PJM Billing," PJM, Oct. 3, 2022. https://www.pjm.com/-/media/DotCom/markets-ops/settlements/custgd.pdf.
[33] Not included in the table are administrative and other fees that comprise a fraction of the costs associated with PJM functions.

2.2.2 Markets

The basic impact to the PJM markets of a load co-locating with existing generation (regardless of Type A or Type B configuration) would be comparable to that of any load connecting to the grid.[34] Directionally, without corresponding addition of new generation, this impact may be an increase in the marginal price of electricity in capacity and energy markets, because in either case, demand is increasing (whether it is behind a generator's meter or in front), without a corresponding increase in supply.[35, 36] Generally, the price ultimately paid by ratepayers is dependent on several factors and the precise location where load is traditionally connected or is co-located plays a role.

Although the Commission does not have the tools to model pricing impacts, the IMM produced reports that estimate capacity and energy cost impacts of co-location with existing nuclear generation.[37] The IMM studied the impact of the Calvert Cliffs Clean Energy Center (Maryland's existing nuclear plant) being wholly dedicated to co-located load and thereby removed as a participant from the PJM capacity market. In a second report, the IMM studied the impact of Peach Bottom Clean Energy Center (another existing nuclear plant) in Pennsylvania being wholly dedicated to co-located load instead. In either case, the removal of a nuclear plant causes significant cost increases across PJM, raises prices in Maryland, and reduces electric supply to below the planning reserve margin. The IMM's analysis found that wholly removing Peach Bottom would be more costly to Maryland than wholly removing Calvert Cliffs.[38] It appears that this difference is because more supply is being removed from the grid when Peach Bottom[39] is entirely dedicated to co-located load than when Calvert Cliffs is entirely dedicated.[40] If instead of removing the full generator in each case, a comparably sized load co-located at either site, cost impacts to Maryland would be the same according to the IMM's analysis.[41]

The IMM's sensitivity analyses further found that removing existing nuclear generation capacity from the PJM markets through co-location would result in large cost increases in the greater PJM region and in Maryland, regardless of whether generation is removed from Maryland or from the

[34] Dr. Bowring, IMM, PC 61 Hr'g. Tr. p. 72, l: 4 - 11. *See also* Constellation Comments, PC 61, Jul. 26, 2024. p. 14.

[35] "All else being equal, if some amount of capacity is removed from the market because of co-location, capacity rates may increase, which may increase [costs to] Maryland ratepayers." Post-Hearing Comments on the Co-Located Load Configuration Study, Technical Staff, PC 61, p. 11.

[36] As discussed in Section 2.1, impact may also include a reduction of the reserve margin, thereby degrading resource adequacy. This could exacerbate cost impacts.

[37] Comments to the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61, the IMM. Sep. 24, 2024. p. 7.

[38] The cost to Maryland of removing Peach Bottom from the latest capacity market auction would have been $620 million while removal of Calvert Cliffs would have been $546 million.

[39] 2,646 MW in total net generation, *see* fact sheet "Peach Bottom Clean Energy Center," Constellation, Jan. 2023.

[40] 1,790 MW in total net generation, *see* fact sheet "Calvert Cliffs Clean Energy Center," Constellation, Jan. 2023.

[41] "Supplemental Comments to the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61," The IMM. Dec. 13, 2024, p. 2.

wider PJM region.[42] Nevertheless, the IMM assessed that similar price impacts would occur whether a load interconnects through traditional means or co-locates.[43]

Ultimately, the IMM assessed that Type B co-located loads may avoid costs that all other load must pay and concluded that the question the Commission and other regulators face is whether, as a matter of policy, the *de facto* provision of special incentives to co-located loads by enabling this cost avoidance should exist.[44]

While the extent to which co-location impacts ancillary service and black start costs relative to load connecting in the traditional manner is not readily clear, it appears that co-location configurations would benefit from ancillary and black start services on the grid.[45] Until or unless FERC resolves whether the benefit from this wholesale service is significant and requires co-located load to pay for these wholesale services, other customers on the system would carry the burden of these payments.

As discussed in Appendix C, among the potential grid reliability impacts attributed to a Type B co-location arrangement is the possibility of a load trip which, regardless of the reason (e.g., a cyber security event,[46]) results in the dedicated generator injecting an unscheduled amount of power onto the grid. This instance could cause grid disturbances and challenge reliability, and would be most concerning at a nuclear plant which, based on its current design limitations, cannot rapidly reduce power. While the grid operator may direct other generators on the system to curtail in order to balance the system and restore reliability, compensating those generators for lost opportunity costs would fall upon other customers on the grid, further increasing the price ratepayers would pay for energy. This could be the case until or unless federal rules are adopted that address these wholesale market issues.

2.2.3 Transmission

Costs associated with FERC-jurisdictional transmission at the wholesale level, which are eventually passed down to retail ratepayers, are composed of those associated with delivery of power to load (transmission service) and with upgrading the grid to maintain system reliability.

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[42] For capacity costs, the IMM ran the following three scenarios: (a) removing 1,000 MW of Maryland nuclear generation, (b) removing all of Maryland's nuclear generation (i.e., Calvert Cliffs,) and (c) removing 10,000 MW of nuclear generation in the entire PJM footprint. In each scenario, the IMM found that capacity prices for Maryland would have increased approximately 29% ($332 million), 49% ($526 million), and 47% ($526 million,) respectively relative to the 2025/2026 base residual auction capacity transfer rights. For energy costs, the IMM only studied the impact of removing significant amounts of generation in the entire PJM footprint (10,000 - 20,000 MW) and estimated a range of price increases. For example, if 10,000 MW of nuclear energy was removed from the PJM region, the IMM estimated that day ahead energy prices would increase 28 - 115% ($32 - $54 billion) relative to the IMM’s modeled results. The cost impacts were much higher under the 20,000 MW scenario. Comments to the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61, The IMM. Sep. 24, 2024. pp. 5 - 7.

[43] Comments to the Maryland PSC Senate Bill 1 Co-location Study Administrative Docket PC 61, The Independent Market Monitor for PJM. Sep. 24, 2024. p. 7.

[44] *Id.*

[45] *See* footnote 8. *See also* Dr. Bowring (IMM) PC 61 Hr’g Tr. at 115.

[46] S*ee* Appendix C regarding NERC cautioning against higher cyber security risks with this co-location.

Transmission service costs are a function of a utility's revenue requirement and the amount of demand a load imparts on the system. As with market costs, Type A load, as Network load, would pay for transmission service while Type B load may not. If a Type B load does not pay, other customers on the system may be allocated higher costs than they would have otherwise been allocated to make up the difference.

Similarly, as the transmission system is upgraded in the future to address reliability, a Type B co-location arrangement which is dependent on the transmission system (as discussed briefly above in regard to ancillary and black start services) could avoid paying for these upgrades absent federal rules addressing this matter. This would remain true if such federal rules do not account for the full extent of the load's power demand and instead simply allow load consumption to be netted against the generator output in a co-location arrangement. This netting procedure could result in the appearance of zero demand on the grid, and grid charges would still be avoided, even though the generator in the arrangement is synchronized to the grid and receiving grid benefits. This possibility is applicable, regardless of whether the co-located generator is existing or new and the burden of these costs would still be borne by customers on the system, regardless of the Commission's retail authority.

Further details addressing reliance on the transmission system and cost considerations are summarized in Appendix D.

2.3 Retail Considerations and Commission Jurisdiction

2.3.1 Retail Cost Allocation

Customers (loads) are typically charged for both wholesale and distribution-level costs through retail rates. Distribution-level costs include utility charges for delivery of electricity, as well as state-level charges and taxes. As discussed further below, a Type B load may avoid these costs, resulting in higher cost allocation to other ratepayers on the system or diminished payment into state policy programs, including the renewable portfolio standard (RPS) and EmPOWER programs.

Application of the Definition of a Retail Electric Customer

Retail rates are the mechanism through which load customers are traditionally charged for wholesale and distribution-level services. The Commission has jurisdiction over retail sales in the State, while FERC retains authority over wholesale sales and transmission rates. Because the load is Network load in Type A co-location configurations, these configurations would request connection to the grid in the traditional manner through a utility. They would connect to the grid as utility customers and would, therefore, naturally be defined as retail customers. Type B co-location, however, is not as clearly categorized. If a Type B co-locating load is not considered a retail customer, the Commission's regulatory authority over this load or with regard to the presence and treatment of this load would be uncertain. This ambiguity could be clarified in the definition of "retail electric customer" or within its exceptions under the Public Utilities Article (PUA). Of consequence is the definition of a retail electric customer in PUA §1–101(ee) which specifies: "'Retail electric customer' means a purchaser of electricity for end use in the state."

Potentially relevant exceptions to this definition and observations regarding the applicability of these exceptions to co-location as written are outlined in Appendix F.

Considerations for Defining the Electric Company

Though a Type B co-located load may be considered a retail customer under the Public Utilities Article (though this warrants clarification, as discussed above,) clarification as to who the retail electric supplier or electric delivery company would be under a Type B arrangement is important.

As defined in PUA §1–101(i): "'Electric company' means a person who physically transmits or distributes electricity in the State to a retail electric customer." There are exceptions to this definition; perspectives on their applicability as they are written in statute are described in Appendix F.

The definition of "electricity supplier" in PUA §1–101(l), which includes an electric company, also merits clarification as it includes similar exceptions to those defined for an electric company.

Unless the role of the generator in a Type B arrangement is defined in the context of electricity supply and/or delivery, the generator may be infringing on a utility's franchise rights by providing electricity to load in a utility's exclusive service territory. Utilities have an exclusive right to serve retail load (and recover costs in rate base) in their respective service territories. Legislatures generally grant utilities this monopoly right to a service territory by statute in exchange for the utility's obligation to serve customers at just and reasonable rates regulated by public utility commissions. The commissions, in turn, grant (or revoke) the authority of the utility to exercise the franchise.

Without clarification on these matters, including in areas that define Commission jurisdiction, uncertainty will remain and ratepayers risk paying more than necessary.

Back Up Power

Co-located configurations may continue to emerge, and some may be structured to make direct use of the grid as back up power. Alternatively, a co-located load at a multi-generator site may wish to directly rely on a second generator at that site that is also serving the grid as backup power in the event that the dedicated generator in the co-location arrangement is offline. In the event that this second unit were to seek a power uprate in order to provide that backup, the Commission would typically have jurisdiction over the certification process to assess whether this arrangement is in the public interest. However, PUA § 7-207 exempts generating facilities used to produce electricity as on-site emergency backup for critical infrastructure from the requirement to obtain a certificate of public convenience and necessity (CPCN). Data centers are included in the definition of critical infrastructure,[47] and therefore the Commission may not have jurisdiction to implement a CPCN process for this arrangement. This situation and the Commission's jurisdiction in this situation merits clarification in the PUA.

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[47] PUA § 1–101(h–1).

Retail Net Energy Metering Practices and Tariff

In general, it is important that mitigations for co-location impacts are carefully considered and do not unintentionally implicate established practices. Net metering is one such established practice that could be implicated and it is recommended that the legislature clarify the distinction between retail net metering and a Type B co-location arrangement. Retail net energy metering practices are summarized in Appendix E.

3. Recommendations for Mitigation

Overall, there is a great deal of uncertainty at the federal level with many stakeholders asking FERC to establish guidance for co-location.[48] Representatives from several states raised co-location concerns at the FERC technical conference on co-location,[49] especially surrounding transparency and standardization, and requesting that FERC clarify the recommended or required approach to co-located arrangements related to the bulk power system. Other state public utility commissions have begun to hold their own technical conferences examining co-location or resource adequacy in general and have opened related proceedings.[50] With national debate ongoing, the State of Maryland can consider establishing its own jurisdictional framework to address co-location, regardless of outcomes at the federal level.

When considering the many mitigation strategies relevant to this report, it is important to consider the potential for new co-location arrangements to come along in the future and for existing ideas that have not been widely applied but have potential to bring a flexibility and resource adequacy benefit to the grid (e.g., hydrogen production as mentioned earlier.) The recommendations below are mindful of this potential while looking to mitigate possible impacts of the configurations being contemplated today.

The Public Utilities Article was not written contemplating the co-location arrangements being proposed today and it is recommended that the General Assembly clarify the extent to which the existing statute applies to co-located load. Considerations for the applicability of certain statutes were discussed in Section 2.3. Based on these considerations, it is recommended that the legislature confirm in statute that the load in a co-location arrangement is a retail electric customer, addressing the arrangement as a retail electric sale subject to Commission jurisdiction. It is also recommended that the legislature clarify whether generators that engage in a Type B co-location arrangement violate utility franchise agreements under the definition of electric company or if they should be granted an exception and what the terms of that exception may be. It is additionally recommended that the General Assembly make clear whether the electric company through which tariffs can be assigned is the utility whose territory the load resides and/or update the PUA to make clear whether any co-location party (i.e. load or generator owner) is an electric company or an electricity supplier, requiring it to meet RPS requirements and pay for offshore wind renewable energy credits (ORECs).[51] Noting that RPS requirements

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[48] *See* generally FERC Docket No.'s EL24-149 & EL25-20.

[49] FERC Docket No. AD24-11-000 Tr. pp. 131-168.

[50] E.g., Virginia State Corporation Commission Case No. PUR-2024-00144.

[51] Comments filed in PC 61, OPC, Jul. 26, 2024. https://webpscxb.psc.state.md.us/DMS/pc/pc61.

and OREC payments are important to the State's clean energy goals, representatives of large loads have expressed interest in contributing to these State programs and contributing to clean energy goals at large.[52]

Because of the importance of the many State programs funded through electric customer charges, the General Assembly should require costs for programs like the Electric Universal Service Program (EUSP) and EmPOWER Maryland, as well as other costs that may be deemed appropriate, be allocated to these large loads. This could be accomplished via a tariff developed by the relevant utility or by some other means that can be regulated by the Commission. With the clarification of jurisdiction over co-located load as a retail customer, the legislature should also ensure that there are rules in place to impose penalties on a co-location arrangement at which load unexpectedly comes onto the grid to preclude the risk of reliability challenges. It is recommended that such rules be accompanied by the requirement that co-location configurations take cyber security precautions to preclude cyber events from causing such reliability challenges. Additionally, the legislature should take note of any CPCN exclusions in statute that may conflict with this jurisdiction as it may apply to new co-located generation or capacity that serves as backup power to data centers.

The General Assembly should define the degree of control the State should exercise over co-location arrangements in Maryland. One approach could be a review process for determining whether each proposed co-location instance is in the public interest before it is allowed to proceed. Similar to a CPCN review, this process would involve expertise from key state agencies.

Finally, large loads could minimize reliability concerns, environmental impacts, and retail customer rates by bringing new, clean generation with them. As FERC Chairman Willie Phillips indicated at the recent FERC conference on co-location, large loads and specifically data centers around the country, can serve as an "anchor" for "the development of the very energy infrastructure that our nation so sorely needs."[53] It is recommended that this approach be encouraged in a manner that ensures reliability, aligns with Maryland's clean energy goals, and protects ratepayers.

4. Conclusion

As discussed throughout this report, some forms of co-location represent novel approaches to connecting load to the grid. However, certain other co-location proposals have the potential to create immediate and significant challenges to the grid, impacting overall resource adequacy and rates charged to customers. These approaches may warrant changes in the PUA and future consideration as variations on those approaches develop. It is important to understand the benefits co-location brings along with its implications, including impacts on ratepayers and State policy in general. The Commission will continue to monitor activities on the federal and regional level and is prepared to assist the General Assembly as these activities and policies evolve.

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[52] Comments filed in PC 61, Data Center Coalition, October 16, 2024. https://appendicywebpscxb.psc.state.md.us/DMS/pc/pc61.

[53] Chair Phillips, FERC Docket No. AD24-11-000 Hr'g Tr. at 9.

Appendix A - Technical Conference Participants

The list of PC 61 commenters and panelists* is as follows:

Calvert County Board of County Commissioners*

Calvert County Chamber of Commerce

Calvert County Delegation to the Maryland General Assembly

Constellation Energy Generation, LLC and Constellation NewEnergy, Inc.*

Data Center Coalition*

Exelon Utilities: Baltimore Gas and Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company*

EFW, Inc.

Maryland Department of Commerce

Maryland Energy Administration*

Maryland League of Conservation Voters

Maryland Legislative Coalition Climate Justice Wing

Maryland Office of People's Counsel*

Maryland Public Service Commission Office of Staff Counsel*

Mechanical Contractors Association of Metropolitan Washington

Mid Atlantic Pipe Trades Association (UA), the International Brotherhood of Electrical Workers (Local 26), and Iron Workers District Council of the Mid-Atlantic States*

Monitoring Analytics, LLC*

Mike Kormos LLC*

Nuclear Energy Institute

Nuclear Powers Maryland

PJM Interconnection, LLC*

ReliabilityFirst Corporation*

Retail Energy Supply Association (RESA)

Senate President Bill Ferguson

Southern Maryland Electric Cooperative, Inc.*

The Potomac Edison Company*

UA Plumbers & Gasfitters Local 5

UA Plumbers & Steamfitters Local 486

UA Steamfitters Local 602

Appendix B - Federal Proceedings

FERC is currently considering several cases that may address the treatment of co-location at the wholesale level. One co-location configuration that has come before FERC's regulatory review is at Susquehanna Steam Electric Station (Susquehanna), an existing nuclear plant within PJM and located in Luzerne County, Pennsylvania. There is a 300 MW data center facility located on-site which Amazon Web Services purchased this year from a subsidiary of the nuclear plant's owner.[54] A proposal was put before FERC to amend the existing generator's interconnection service agreement (ISA) to authorize the data center to draw an increased capacity of 480 MW total from the existing plant.[55] On November 1, 2024, FERC issued a ruling rejecting the amended ISA on the grounds that the changes made to the ISA were not demonstrated to be necessary deviations due to "specific reliability concerns, novel legal issues, or other unique factors."[56] On November 20, 2024, Susquehanna filed a request for rehearing which is still pending before FERC.[57]

Also at the federal level, multiple entities have asked FERC to make decisions regarding co-location. Some entities have requested that FERC effectively disallow Type B co-location while others are requesting that this type of co-location be allowed and added to the official PJM tariff.[58, 59, 60] These proceedings are ongoing at this time.

To gain an understanding of the co-location topic and how entities are examining it around the country, FERC held a technical conference on November 1, 2024.[61] Entities represented at the conference and involved in the larger conversation around co-location include NERC, PJM, IMM, regional grid planners, independent experts, private generation and large load developers, and state agencies. Conversation at the conference included discussion of federal and state jurisdiction on this topic and opportunities for action to address the issue at the federal level. Ultimately, action related to co-location at the state level may need to be revisited if co-location is formally addressed by FERC.

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[54] Allison Good, "Talen Energy sells Pa. datacenter campus to Amazon Web Services for $650M," S&P Global, Mar. 4, 2024.

[55] Order Rejecting Amendments to Interconnection Service Agreement, FERC Docket No. ER24-2172-001 (Nov. 1 2024). https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20241101-3061.

[56] *Id.*

[57] Request for Rehearing of Susquehanna, LLC, FERC Docket No. ER24-2172-001 (Nov. 20 2024). https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20241120-5208.

[58] Baltimore Gas and Electric Company and PECO Energy Company Petition for Declaratory Order, FERC Docket No. EL24-149 (Sept. 30, 2024). https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240930-5354.

[59] Exelon Federal Power Act Section 205 Tariff Amendment Filings under FERC Dockets Nos. ER24-2888, ER24-2889, ER24-2890, ER24-2891, ER24-2893, and ER24-2894.

[60] Complaint Requesting Fast Track Processing of Constellation Energy Generation, LLC, FERC Docket No. EL25-20 (Nov. 22 2024). https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20241122-5285.

[61] FERC Commissioner-led Technical Conference Regarding Large Loads Co-Located at Generating Facilities, FERC Docket No. AD24-11-000 (Nov. 1, 2024). https://www.ferc.gov/news-events/events/commissioner-led-technical-conference-regarding-large-loads-co-located.

Appendix C - Transparency & Standardization

Beyond resource adequacy, a number of concerns have been raised by stakeholders related to the transparency and standardization of the treatment of Type B co-located loads. Generally, to the extent that there is a lack of transparency and necessary standardization in a grid planning process, grid operators may be inadequately prepared to deal with scenarios that stray from normal operations. Type B co-location proposes a novel treatment of load in the PJM region and approaches to grid planning are not fully established as regional and state entities build their understanding.

C.1 Comprehensive Planning

Concerns have been raised about the degree of rigor and inclusiveness of the study process that a co-located load would go through. Reliability studies are completed by PJM, by the relevant transmission owner (TO)[62] or by both parties when a new large load requests interconnection. If reliability violations[63] on the grid are identified as being caused by the load as part of this study process, it has been indicated by PJM that necessary upgrades to resolve these violations will be completed before a large load comes online[64] in accordance with PJM's and the TO's responsibilities to reliability.

The procedure for studying the interconnection of a co-located load may vary based on the type of co-location arrangement. For Type A load, a typical procedure consists of a transmission owner studying the interconnection of this load for reliability impacts. Once this analysis is complete, the TO delivers the results to PJM for it to conduct a "do-no-harm" analysis.[65] The associated load growth is then entered into PJM forecasting as a "load adjustment"[66] and the load is subsequently included in future grid planning processes.

The procedure for studying Type B load is not a matter of settled policy. Nevertheless, based on one known existing Type B configuration in the region and PJM guidance that has not been formally established in its tariff, a Type B co-located load could be studied through a procedure that differs from the standard process for Type A load. Specifically, this arrangement could be studied as a modification to a generator's existing or proposed generator interconnection agreement.[67] Under this study process, only PJM is required to study the arrangement for reliability impacts to the grid under its "Necessary Study" process. TO participation to complete its own study process following PJM's study appears to be allowed, though not necessarily

[62] Note that often the TO and the local distribution utility may be the same entity.

[63] E.g., voltage issues, fault current, short circuit, stability issues, thermal issues, etc.

[64] Mr. Khan representing PJM, PC 61 Hr'g Tr. at 13.

[65] PJM Regional Transmission Expansion Plan (RTEP), p. 61, Mar. 7, 2024.

[66] PJM RTEP, p. 18, Mar. 7, 2024. *See also* PJM Manual 19: Load Forecasting and Analysis, Rev. 36, Nov. 15, 2023, pp. 14, 27. *See also* PJM's preliminary load forecast as cited in footnote 26, which included load adjustments.

[67] Prior to January 2023, this type of agreement was called the Interconnection Service Agreement (ISA). Since the Susquehanna plant entered into an interconnection agreement with PJM prior to January, 2023, it has an ISA to which modifications were proposed for a co-locating data center.

required.[68, 69] In any event, PJM has not disclosed the specifics of any studies it currently has underway regarding these arrangements.

While some stakeholders have cited concerns regarding differences in how comprehensive each of these study processes may be, the scope of these various forms of study is unclear. Conflicting accounts have been provided regarding how comprehensive versus how localized each study would be.[70]

C.2 Obligation to Serve

PJM and transmission owners have an obligation to serve all load seeking interconnection.[71] Since there is no corresponding obligation for PJM or TOs to serve certain forms of co-location, namely, Type B co-located load, there would appear to be potential reliability concerns with this approach.

Under the assumption that there is no obligation to serve this load, PJM has stated that Type B loads would not become incorporated into its future planning processes *as loads*:[72]

> "[Type B] co-located loads are not part of the PJM load forecast because these loads are off the system despite being in the PJM Region. These loads are electrically connected to the grid via the co-located generator, but should never withdraw power from the PJM system….Therefore, the PJM planning models will not recognize this load and the grid as a whole will not be planned and enhanced to serve it."[73]

This treatment of Type B co-located load could lead to a large load coming onto the grid unexpectedly which could have significant impact if not sufficiently planned for.[74] This could happen in the event that protective equipment meant to prevent the load from drawing power

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[68] PJM Interconnection, L.L.C., Open Access Transmission Tariff (OATT), Part IX Subpart G, Docket No. ER24-1987-000 (May 31, 2024).

[69] There appears to be some degree of concern about the extent to which utilities would be able to study a Type B co-located load (*see* Mr. Krieger representing SMECO, PC 61 Hr'g Tr. at 174-175.) While a utility would not be the first to study, as it would be with Type A load, PJM appears to have incorporated utility studies into its procedures for some Type B co-location thus far (*see* Constellation complaint cited in Appendix B of this report, pp. 8-9.) It is not clear whether utility participation in the study process would occur in all cases of Type B co-location.

[70] Comments filed in PC 61, Michael Kormos, Oct. 16, 2024. Mr. Duane representing Copper Monarch LLC, FERC Docket No. AD24-11-000 Hr'g Tr. at 46.

[71] *See* 16 U.S. Code §824q. At the State level, Maryland law provides: "A public service company shall furnish equipment, services, and facilities that are safe, adequate, just, reasonable, economical, and efficient, considering the conservation of natural resources and the quality of the environment." PUA §5-303.

[72] Type B co-located loads would, presumably, be incorporated into generation-side modeling in the sense that they reduce available capacity injection from co-located generation.

[73] *See* footnote 8.

[74] Comments filed in PC 61, ReliabilityFirst Corporation, Jul. 25, 2024, p. 2-3. *See also* filed responses to questions from the Commission (see "Q3" specifically) in PC 61, PJM Interconnection, Dec. 17, 2024.

from the grid fails, though that possibility is highly unlikely and co-locating entities can be penalized if it were to occur.[75, 76]

Unexpected load on the grid could also occur on a less immediate timescale. PJM has raised concern about the possibility of political, regulatory, and other social forces exerting pressure to secure grid service to a large load without interruption if the co-located generator becomes unavailable[77]—in the event of generator retirement, for example. This eventuality could pose a reliability risk on a grid that has not been planned to serve this large load.[78]

Another possible way in which lack of inclusion of Type B co-located load in the load forecast could become a reliability concern is through the use of the grid (or a second generating unit on site that is synchronized to the grid) as back-up power[79] in the event that the exclusively-dedicated co-located generation is not available. Again, if the grid is not planned with the assumption that a large load might come online and use the grid as back-up power when a co-located generator is unavailable, this may pose reliability risks. If PJM is informed that a Type B co-located load plans to use the grid as back-up and allows this to go forward, it would be obligated to plan the grid for this possibility. There is no established policy that it would or would not do so.

The converse of load unexpectedly coming onto the grid may also occur. It is possible that a co-located load trips offline (or trips and switches to back-up power) and an excess of power from the co-located generator is suddenly added to the grid. This circumstance could also cause grid reliability impacts if protective equipment systems are not carefully designed and coordinated by co-locating entities and grid operators.[80] In contrast, for Type A co-located load, where there is a clear obligation to serve, the load would be studied and planned for with this obligation in mind and would be included in forecasts for future planning.[81]

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[75] H. Ito et. al., CIGRE Reliability Survey on Equipment, Dec. 2021. https://cse.cigre.org/cse-n023/cigre-reliability-survey-on-equipment.html.

[76] Concerns about equipment failure are addressed in PJM's co-location guidance with a discussion of, first, ensuring the protective equipment scheme is robust. If this scheme were to fail, PJM guidance indicates that settlements and compliance implications for unexpected load on the grid would be assessed. The State could similarly impose penalties on a co-location arrangement at which load unexpectedly comes onto the grid. (*See* footnote 7 for PJM Guidance citation.)

[77] *See* footnote 8.

[78] Note that PJM has also indicated in its guidance (cited in footnote 7) that "The co-located load configuration that is studied and memorialized in a PJM service agreement may not be changed unless the Interconnection Customer undergoes a subsequent necessary studies process and the results of such process are memorialized in an amended service agreement." It is concerning that PJM considers it a possibility that political pressure may compel the grid operator to potentially forgo this guidance and allow a load to be served by the larger grid without proper safeguards in place.

[79] Representatives from the IMM and ReliabilityFirst have noted the possibility that a co-located load could use the grid or a second unit as backup power. *See* Dr. Bowring (IMM) PC 61 Hr'g Tr. at 40. *See also* Mr. Thiry representing ReliabilityFirst, PC 61 Hr'g Tr. at 31.

[80] *See* filed responses to questions from the Commission (see "Q3" specifically) in PC 61, PJM Interconnection, Dec. 17, 2024.

[81] *See* footnote 8.

C.3 Cybersecurity

NERC has expressed concern that co-location brings heightened cybersecurity risks, raising the possibility that "a cyber issue on either the generation or load side could propagate to the other."[82] PJM has noted this concern[83] and NERC has indicated that there are methods available to prevent shared access to load and generation in the event of a cyber attack. However, no known standards have been enacted regarding cybersecurity of co-location configurations.

[82] Statement of Howard Gugel on behalf of NERC in Docket No. AD24-11-000.

[83] *See* filed responses to questions from the Commission (see "Q4" specifically) in PC 61, PJM Interconnection, Dec. 17, 2024.

Appendix D - Wholesale Cost Allocation to Co-Located Load

Cost impacts to Maryland ratepayers are determined based on how a co-located load affects wholesale costs, how much a co-located load itself contributes to paying those costs, and ultimately how these costs are allocated at the wholesale and retail levels. Each of these elements of impact is somewhat case-specific and at the core of determining rate impacts will be policy makers' determination of whether all forms of co-located load should be subject to allocation of grid costs.

Allocation to Type A co-location configurations should generally follow standard rate design principles. Standard federal and State rules addressing costs and cost allocation apply and ratepayer impacts should be no different than if the load interconnected in the traditional manner.

Determining cost allocation to Type B co-location is more complicated. As discussed in Section 2.2.2, load co-locating or connecting to the grid in the traditional manner, all else equal, appears to place similar price pressures on the markets. However, Type B may not contribute to the payment of associated costs. Type B co-location may also avoid transmission upgrade costs.

The following subsections provide some additional background on the cost allocation process and the surrounding debate.

D.1 Cost Categorization

There are two main cost categories in a retail electric customer's bill—wholesale and distribution-level charges.

Generally, wholesale costs (e.g. market costs) are allocated by PJM to Load Serving Entities and/or electric distribution companies, which then pass these costs through to retail ratepayers via standard offer service or retail choice contracts. See Section 2.2.1 for a description of wholesale cost categories.

Distribution-level costs are charged to customers by distribution utilities and are regulated by the Commission. Charges and allocation vary by customer class and applicable tariff, but they generally include the cost of utility charges for delivery of electricity on the wires it owns, Maryland state-level charges for funding social programs, and local taxes.

Cost impacts may also be split into those that occur at the time a co-located load is going through the process of interconnecting to the grid and those that occur once the co-location arrangement is in place. Costs that occur at the time of initial grid connection include those associated with system upgrades that have been identified by grid planners as needed to ensure reliability of the transmission system. Costs that occur after a co-location arrangement is in place include costs associated with wholesale markets and transmission service, as well as future grid upgrades. Distribution-level costs are also relevant once load is brought online.

D.2 Wholesale Cost Allocation

As previously discussed, FERC is being asked to clarify PJM tariff structures around co-located load. This discussion at the federal level may have some bearing on the extent to which wholesale costs can clearly be assessed to Type B co-location arrangements, but the following provides a sense of where this issue currently stands.

D.2.1 Avoidance of Wholesale Costs

Generally, Type A co-located load is expected to be treated like all Network customers and to participate in payments of wholesale costs through established PJM cost allocation procedures. Type B co-location could avoid all wholesale costs (except for some transmission upgrade costs discussed below) by nature of it being considered "off system."[84] Because load connecting to the grid, whether it is co-located or not, has a cost impact, this means that other customers could pay a larger percentage of wholesale costs than they would have otherwise while Type B co-located entities would not pay a large portion of these costs. This distinction applies regardless of whether the co-located generator is existing or new.

Whether or not this cost distribution is fair is currently being debated in several forums. Many stakeholders consider the fairness of this arrangement to be based on the degree to which load benefits from use of the transmission system and many have weighed in on this question of use.[85]

PJM, alongside other parties, contends that all load that is co-located with a generator that itself is connected to and synchronized with the grid benefits from the use of the transmission system. Therefore, parties have indicated that it would seem appropriate for co-locating entities in this configuration to contribute some level of payment for the cost of grid upkeep.[86] For example, the IMM has indicated that Type B co-location raises complex policy questions that can be avoided if co-located load is located in front of a generator's meter (allowing Type A configuration only.)[87] Not all parties raising cautions about Type B co-location have expressed that it should be

[84] PJM has indicated in its guidance that Type B co-locating entities would avoid such costs through the netting of the consumption of the co-located load with the dedicated output of the co-located generator. (*See* PJM Guidance, p. 2, item 2.) The resulting net load (or lack thereof) could then presumably be used in the determination of the amount of cost allocated to a Type B load. When the consumption of load matches the output of the generator, there would appear on the grid to be zero demand. Since grid charges typically reflect a level of demand on the grid, such netting could reduce costs allocated to this load down to zero. This netting procedure is not a matter of established policy, but is indicated as the process PJM would theoretically employ in its co-location guidance.

[85] Note that, as has been described by one party at the federal level, this is not the only cost allocation principle that could be applied. Fairness may also be viewed under the principles of system impact and resulting cost causation. *See* Mr. Duane representing Copper Monarch, LLC, FERC Docket No. AD24-11-000, Hr'g Tr. at 32-34.

[86] *See* footnote 8. *See also* Dr. Bowring (IMM) PC 61 Hr'g Tr. at 115. *See also* Comments of Southern Maryland Electric Cooperative, Inc. on Co-Located Load Configuration, SMECO, PC 61, Jul. 26 2024, p. 2.

[87] Dr. Bowring (IMM) PC 61 Hr'g Tr. at 102, 115, 145.

disallowed,[88] but many stakeholders have indicated that co-locating entities should pay for ancillary and black start services.[89]

Proponents of Type B co-location have argued that a load in this configuration would always be fully isolated from the larger grid due to protective equipment and would pay for electricity service through a bilateral contract with a co-located generator and, therefore, would not make direct use of the transmission system.[90] Advocates do concede that Type B arrangements could have some amount of reliance on certain ancillary and black start services through a co-located generator's interconnection with the grid but they commonly argue that requiring such payments from co-locating entities would require a fundamental market redesign.[91] They further contend that such services are a small portion of wholesale costs, implying that these payments are not worth expending the effort to determine cost allocation procedures.[92]

Data center representatives engaging on the topic of co-location in Maryland have indicated that they support paying their "fair share" of costs, noting that this fair share should be based on the services they receive. They have also expressed willingness to contribute to state programs.[93, 94] One major data center interest has stated in a federal proceeding that it is not looking to co-locate based on a desire to avoid infrastructure costs and would prefer to co-locate in a Type A configuration.[95]

D.2.2 Transmission Upgrades

The discussion of cost allocation associated with transmission upgrades warrants consideration beyond other wholesale costs. First, that is true because costs associated with transmission upgrades can be significant, totaling over $5 billion in PJM's most recent planning process.[96] Additionally, as grid infrastructure continues to age, the necessity for additional transmission work is likely to increase. Second, Type B co-location may be treated somewhat differently in this allocation than in other wholesale categories. While Type B co-located load may avoid most wholesale costs, there has been some indication that co-locating entities in this configuration would be required to pay certain transmission upgrade costs. However, co-locating entities in this type of configuration may avoid, and even perpetually avoid, a portion of the transmission

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[88] PJM has indicated a preference for co-located load to be served as Type A load, but PJM has stated it cannot restrict Type B co-location arrangements as they are private transactions. *See* Mr. Khan representing PJM, PC 61 Hr'g Tr. at 53-55.

[89] *See* footnote 8. *See also* Dr. Bowring (IMM) PC 61 Hr'g Tr. at 115. *See also* Mr. Weaver representing Exelon, PC 61 Hr'g Tr. pp. 156-157.

[90] Mr. Emnett representing Constellation, PC 61 Hr'g Tr. at 264-265. *See also* "The Co-Located Load Solution," Michael Kormos, Jul. 2024, pp. 7 and 13-14.

[91] Mr. Emnett representing Constellation, PC 61 Hr'g Tr. at 308-309. *See also* "The Co-Located Load Solution," Michael Kormos, Jul. 2024, pp. 12-13 and 16.

[92] Mr. Emnett representing Constellation Energy, FERC Docket No. AD24-11-000 Hr'g Tr. at 126-128. *See also* Mr. Muller representing Talen Energy Corporation, FERC Docket No. AD24-11-000 Hr'g Tr. at 129.

[93] Ms. Quinlan representing the Data Center Coalition, PC 61 Hr'g Tr. at 313-316.

[94] Re: DCC Comments Following Public Conference PC 61, Data Center Coalition, PC 61, Oct. 16, 2024. pp. 2 - 3.

[95] Post-Conference Comments of Google, LLC, FERC Docket No. AD24-11-000, Dec. 10, 2024, p. 3.

[96] PJM Interconnection, L.L.C., 187 FERC 61,012 (2024). https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240408-3047.

upgrade costs that they cause. Two possible scenarios relevant to cost allocation for co-location are described below.

First, new entry of load could cause a significant enough change in power flows that some equipment may be overloaded at the time of interconnection. Grid operators identify these types of reliability challenges in study processes prior to a load coming online. If these challenges are identified, upgrades would be required before the load could reliably connect (*Scenario 1*).

Alternatively, a new load's grid impact could push equipment closer to its allowable limit without overloading it. There would be no immediate upgrades needed and a grid operator may connect the load without any grid upgrades. However, the next load to come online might cause an overload and upgrades may be needed that customers would pay for (*Scenario 2*).

The above scenarios are expected and typical on the grid, as grid operators have an obligation to serve load, and collectively, load can cause the need for upgrades to ensure that grid safety and reliability is maintained. However, the table below illustrates the potential for Type B co-locating entities to avoid paying costs associated with these upgrades while other customers would pay.

	Scenario 1	*Scenario 2*
Type A	Participates in payment for any necessary upgrades at the time of interconnection through established PJM processes for Network load on the grid.[97]	Participates in payment for necessary upgrades on the grid at large after the co-location arrangement is in place through established PJM processes for Network load on the grid.
Type B	May be held responsible for costs at the time of interconnection.[98]	Would cause impact by bringing the grid closer to needing upgrades, but could avoid participating in payment for future upgrades alongside other customers.

[97] Type A and Type B are the two ways co-location has been categorized in ongoing discussions, but there are possible variations within these two main categories. Per PJM guidance, if a co-located load is of Type A (PJM Network load,) the generator or a portion of the generator that it is sited with may be able to elect to be designated as behind-the-meter generation (BTMG), as established under PJM's tariff. This becomes relevant when discussing cost allocation. If a load is co-located with BTMG, the generation and load may be netted when PJM allocates wholesale costs. Determination of whether a generator may be designated as BTMG at the wholesale level is under the jurisdiction of FERC. This variation of Type A co-location is not discussed in detail in this report but helps to illustrate the complexities of these issues. *See* PJM Interconnection, L.L.C., Open Access Transmission Tariff (OATT), §36.1A, Docket No. ER24-1987-000 (May 31, 2024). https://agreements.pjm.com/oatt/4092. *See also* PJM Manual 14D, Appendix A: Behind the Meter Generation Business Rules. https://www.pjm.com/-/media/documents/manuals/m14d.ashx.

[98] This could occur through customer-funded upgrades in the PJM Regional Transmission Expansion Planning process. Customer-funded upgrades are paid typically by a generator or transmission facility requesting interconnection, but because Type B co-located load could come online through a generator's amended interconnection service agreement, PJM has indicated it would hold the generator responsible for costs caused by Type B load at the time of interconnection. (*See* Mr. Khan representing PJM, PC 61 Hr'g Tr. at 13.)

Regardless of whether Type B co-locating entities pay for initial upgrades, there is the possibility that they could request an increase in load on-site (similar to the Susquehanna co-location described in Section 1.2.3), and enter again into either *Scenario 1* or *Scenario 2*. If co-locating entities continue to request increases at a site and end up in *Scenario 2* each time, then these entities could perpetually take up available capacity or lean on the grid without ever paying.[99]

[99] Often upgrades to the system are made with extra margin on equipment ratings (e.g., a line might be upgraded to allow for 150 megawatts of capacity when only 120 megawatts are needed) so there would be room available for more load to come online. A co-located load could take advantage of this margin by incrementally requesting to increase its demand, potentially without ever triggering upgrades. A co-located load could continually do this whenever the grid is upgraded.

Appendix E - Retail Net Energy Metering Practices and Tariff

Net metering is a method by which a single meter is used to capture both a customer's energy usage and the energy produced by a renewable energy generator that is connected to the distribution system. Net energy metering generally utilizes the existing meter for all calculations, avoiding the expense of a second meter to measure incoming and outgoing energy separately. Maryland law currently permits net metering for solar, wind, biomass, micro combined heat and power, fuel cell, and closed conduit hydroelectric generating facilities intended to supply all or part of a customer’s annual energy usage. The term “net metering” refers to the measurement of electricity on the basis that it is the net of energy used and produced by an eligible customer-generator during a single billing period, which is usually one month. The terms of utility tariffs require a customer to pay the monthly utility customer charge, regardless of the amount of energy produced. However, for energy billed, the customer pays only for energy used, netted against any generated energy that the customer produces. Net metering generally acts as an incentive for customers to invest in distributed renewable generation in that this construct saves customers money while also contributing to state-level renewable portfolio standards and clean energy goals.

Net metering was first conceptually established in 1978 as FERC was undergoing the process to implement the Public Utility Regulatory Policies Act (PURPA), a measure to promote greater use of renewable energy. In FERC Order No. 69, FERC recognized that net billing arrangements are appropriate in some situations and left the decision of establishing net billing arrangements up to state regulatory authorities.[100] Since this decision, numerous states have established net metering programs to promote renewable energy at the residential scale within the individual state. On multiple occasions since the implementation of net metering by states, efforts have been made that seek to move “net metering” jurisdiction to the FERC level rather than the state level. In each of these occasions, FERC has affirmed its decision and deferred net metering jurisdiction to the states rather than to FERC itself.[101] For example, in FERC’s decision in 2001 related to a petition from MidAmerican Energy Co., FERC determined that there is “no reason, therefore, to interfere with the Iowa Board's determination to permit net metering, and to permit it on a monthly basis.” Furthermore, the Energy Policy Act of 2005 included amendments to PURPA that required utilities to offer net metering to customers who request it and defined “net metering” as “service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.” The Energy Policy Act of 2005 also emphasized states’ ability to control net metering programs, but did not specify the rate at which net metering customers should be compensated for the electricity they generate and send to the

[100] FERC Order No. 69 issued on February 25, 1980.

[101] *See* MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001); SunEdison LLC, 129 FERC ¶ 61,146 (2009); Petition for Declaratory Order of New England Ratepayers Association Concerning Unlawful Pricing of Certain Wholesale Sales, New England Ratepayers Association, 172 FERC ¶ 61,042 (2020).

grid, which provides a strong argument that the Energy Policy Act of 2005 did not intend to allow FERC to have jurisdiction over net metering programs.

Net metering is an established policy and particular tariff choice, intended to foster innovation and deployment of renewable energy generation. Tariffs that may be required to be developed by the Commission for large load interconnecting with wholesale generation can and would be different and would incorporate different considerations than for typical net metering configurations.

Appendix F - Exceptions in the Public Utilities Article

The following are observations regarding exceptions related to definitions in the PUA which may be related to co-location.

F.1 Definition of a Retail Electric Customer

As discussed in Section 3, it is recommended that the legislature confirm in statute that the load in a co-location arrangement is a retail electric customer.

The definition of a retail electric customer in PUA §1–101(ee), provides: "'Retail electric customer' means a purchaser of electricity for end use in the state." Exceptions to this definition and perspectives on their applicability as written are described below.

The first exception[102] is "an occupant of a building in which the owner/operator or lessee/operator manages the internal distribution system serving the building and supplies electricity and electricity supply services solely to occupants of the building for use by the occupants." While it could be argued that a load co-located with one of its generating facilities would be excepted from consideration as a retail electric customer because the generator is supplying the load as a tenant that occupies a building, the exception is contingent on an owner/operator or lessee/operator supplying electricity and electricity supply services *solely* to occupants of the building. Unless a co-locating load takes up all available electricity supply at Calvert Cliffs, this exception may not apply. However, the application of this exception vis-à-vis a Type B arrangement merits clarification.

The second exception[103] that might apply is "a person who generates on-site generated electricity, to the extent the on-site generated electricity is consumed by that person or its tenants." This exception may apply to certain co-location arrangements; the legislature should clarify whether it is intended that this exception apply to a Type B arrangement. Outside of the circumstance in which the generator and load are owned by the same entity, the applicability of the exception for electricity consumption by tenants to a co-location arrangement merits clarification. While the generator in the co-location arrangement may be supplying energy to its tenant, the statute does not specify whether or not the generator can be synchronized to the grid and capable of providing energy or ancillary services consumed by others and still qualify as an exception to this definition.

F.2 Definitions of the Electric Company & Electricity Supplier

As discussed in Section 3, it is recommended that the role of the generator in Type B co-location configurations be clarified. The definitions of electric company and electricity supplier are relevant to this clarification. Exceptions to the definition of an electric company in PUA §1–101(i) (which are similar to the exceptions for the definition of an electricity supplier in PUA §1–101(l)) are discussed below.

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[102] PUA §1–101(ee)(3)(i).

[103] PUA §1–101(ee)(3)(ii).

As defined in PUA §1–101(i): "'Electric company' means a person who physically transmits or distributes electricity in the State to a retail electric customer." Exceptions to this definition are as follows:

> (i) Certain persons "who supply electricity and electricity supply services solely to occupants of a building for use by the occupants"
>
> (ii) "any person who generates on–site generated electricity"
>
> (iii) "a person who transmits or distributes electricity within a site owned by the person or the person's affiliate that is incidental to a primarily landlord–tenant relationship."

As with the definition of a retail electric customer, an exception applies if generation and load are owned by the same entity. That is, a person who generates on–site electricity for themselves would not be considered an electric company subject to the Commission's authority to regulate retail rates, just as a person who generates on-site electricity would not be considered a retail customer.[104]

During the Commission's PC 61 Technical Conference and in post-conference comment filings, Constellation Energy (Constellation), owner of the Calvert Cliffs Nuclear Power Plant in Maryland, argued that it would not be in violation of the exclusive utility franchise rights of Southern Maryland Electric Cooperative, Inc. (SMECO), the utility in whose service territory Calvert Cliffs sits, if Constellation were to serve a data center that would be co-located in a Type B configuration with Calvert Cliffs. Constellation has argued that under this co-location scenario, it should be considered a landlord while the data center load should be considered a tenant, pursuant to PUA §1–101(i).[105] This argument could be plausible if, for example, a co-location arrangement with a nuclear plant provided the load customer significant services or benefits aside from the provision of electricity, such as the convenience of being sited away from residential centers to reduce noise and other impacts or the provision of water for cooling systems. This latter benefit introduces other regulatory uncertainties beyond the scope of this review.[106] Nonetheless, defining the transmission and distribution of electricity as "incidental" to the landlord-tenant relationship for a large load customer, as required by the PUA exception, is tenuous,[107] especially since transmission and distribution of electricity from a large generator is one of the primary reasons a large load would co-locate at that location. However, addressing in legislation the relevance of this exception as it pertains to Type B configurations could provide certainty.

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[104] This exception is further set forth in PUA §7-207.1 which lays out rules for on-site generated electricity. These rules allow for the situation in which on-site power is generated for a person's own use and this would not be considered a utility franchise violation.

[105] Mr. Emnett representing Constellation (affirmative in response to Commissioner Suchman), PC 61 Hr'g Tr. at 349-350.

[106] Aside from how the legislature clarifies this area of uncertainty with regard to the electric aspects of co-location, if the load, or tenant, in this arrangement receives other services that are regulated, such as water for cooling the load's facilities, co-location may introduce other areas of regulatory uncertainty beyond the scope of this report.

[107] Mr. Fields representing Office of People's Counsel, PC 61 Hr'g Tr. at 414-415. *See also* Comments of Southern Maryland Electric Cooperative, Inc. on Co-Located Load Configuration, SMECO, PC 61, Jul. 26 2024, pp. 4-5.

Appendix G - September 24, 2024 PC 61 Technical Conference Transcript

[Copies of the September 24, 2024 transcript for Maryland PSC Case No. PC 61 may be purchased from CRC Salomon, Inc., the Commission’s court reporter.]