Title 20 PUBLIC SERVICE COMMISSION

Subtitle 50 SERVICE SUPPLIED BY ELECTRIC COMPANIES

Chapter 13 Virtual Power Plants

Authority: Public Utilities Article, §§2-113, 2-121, 5-101, 5-303, §§7-1001-1006 and 7-306, Annotated Code of Maryland

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20.50.13.01 Scope[5]

A. Scope:

(1) The scope of this Chapter applies to processes, interfaces, communications, data access, technical requirements and tariffs for EDCs and DERAs to facilitate efficient and reliable provision of electric distribution support services or wholesale market grid services[6] from VPPs.

(2) While the scope of this Chapter does include requirements for Maryland licensed DERAs to interface with EDCs as directed by the PJM Interconnection LLC for the purpose of implementing the PJM DER Aggregator Participation Model, the scope of this Chapter does not apply to processes, interfaces, communications and technical requirements not directed to EDCs and solely under the jurisdiction of the PJM Interconnection LLC.[7]

(3) Pursuant to FERC Order No. 2222 electric cooperative utilities and municipal electric utilities are exempt from the applicable requirements in this Chapter unless they have opted-into FERC Order No. 2222 provisions for VPPs in their service territory. Pursuant to Public Utilities Article §§7-1001- 7-1007, *Annotated Code of Maryland.*

(4) All investor-owned, electric cooperative utilities and municipal electric utilities are subject to this Chapter for DERAs participating in either the PJM DER Aggregator Participation Model or a Retail Tariff Participation Model framework for permanent electric distribution support services.[8]

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[5] Previous versions included a Section B for an Implementation Plan and Section C Applicable Standards involving references to the (1) National Institute of Standards and Technology Handbook 44 – 2023 Section 3.40. for Electric Vehicle Fueling Systems for electric vehicle equipment submetering, (2) Institute for Electrical and Electronic Engineers (IEEE) 2030.5-2023, Standard for Smart Energy Profile Application Protocol for distributed energy resource aggregations in their service territory and (3) The International Electrotechnical Commission (IEC) Common Information Model, particularly IEC 61970, 61968, 62735 and 62746. These sections have been removed due to direction from the Commission on DER Registries, metering and communication in Order No. 92398 on Electric Utilities' VPP/DER Conceptual Reports and Office of Cybersecurity Status Report. Case No. 9778 (ML 329817).

[6] This Subsection was modified due to an Exelon request for clarification.

[7] This Subsection was modified due to an Exelon request for clarification. The revised subsection clarifies that EDC and DERA interfaces are under Maryland Public Service Commission jurisdiction, but interfaces between PJM and the DERA that are not directed to EDCs are not under Maryland Public Service Commission jurisdiction. The Sierra Club feels that this regulation is too broad and unclear.

[8] This Subsection was modified due to Exelon and Sierra Club requests for clarification.

(5) Electric distribution support services pilot programs pursuant to the DRIVE Act as codified in Public Utilities Article §§7-1001- 7-1007, *Annotated Code of Maryland* are exempt from this Chapter until they transition to a Retail Tariff Participation Model framework for permanent electric distribution support services., at which time they are subject to this Chapter.[9]

[9] This Subsection is needed because DRIVE Act pilots are being implemented without regulations, but subject to Commission Orders.

20.50.13.02 Definitions

A. In this chapter, the following terms have the meanings indicated.

B. **Terms Defined.**

(1) "Component DER" means a resource that is located on an electric distribution system that may participate in the PJM DER Aggregator Participation Model or the Retail Tariff Participation Model, or both and is associated with one EDC account number[10][11].

(2) "Curtailment resource" means a resource that provides grid services by reducing electric load.[12]

(3) "Device level meter" means measurement equipment that collects and transmits DER data after the EDC Point of Interconnection that meet the configuration and performance requirements laid out in the applicable Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model or in this Chapter.

(4) "Retail VPP" means a VPP that can only be dispatched by a DERA to respond to an EDC's direction for distribution electric grid services.

[10] Exelon proposed a definition that "Component DER" means a resource that is located on a distribution system that participates in the Energy, capacity and/or ancillary services markets of PJM through the DER Aggregator Participation Model. A Component DER may not exceed 5 MW. A Component DER is associated with one EDC account number and may include several "DERs" While the definition edited is in the same spirit of the Exelon proposal, it has been modified to simplify the definition by relying on other definitions. The size of a DERA is described in the VPP Review section so it is not included in the definition.

[11] Potomac Edison recommends that the DER definition aligns with FERCs definition of DER. Per the FERC Order No. 2222, "DERs are small-scale power generation or storage technologies (typically from 1 kW to 10,000 kW) that can provide an alternative to or an enhancement of the traditional electric power system. These can be located on an electric utility's distribution system, a subsystem of the utility's distribution system or behind a customer meter. They may include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment.

[12] OPC proposed definition

(5) "Dispatchable range"[13] means the lower and upper limits, in MW, that can be dispatched from a set of Component DER, as determined in 20.50.13.05. The dispatchable range may apply to all or a subset of component DER in a VPP.

(6) "Distributed energy resource, or DER" has the same meaning as distributed energy resource as defined in Regulation .02(B) of Chapter 9 of this subtitle.[14]

(7) "Distributed energy resource aggregator" or "DERA" means an entity that aggregates one or more Component DERs into VPPs to provide grid support services in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model.

(8) "EDC, or electric distribution company" means "Electric Company" as defined in Public Utilities Article, §1-101, Annotated Code of Maryland unless it has not opted into the requirements in this Chapter as specified in Regulation .01A(3).

(9) "EDC VPP" means an EDC program where an individual Component DER or groups of DERs are aggregated and dispatched through either utility-owned or third-party Distributed Energy Management Systems at an EDC's direction in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model.

(10) "Grid Services" means the dispatch and control of a VPP in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model, or both, to supply a grid need.

(11) "Heterogenous VPP" means a VPP consisting of injectable and curtailment resources[15].

[13] PJM uses dispatchable range terminology instead of dispatchable capacity limits in submitting bidding parameters into the Day-ahead Energy Market and Real-time Energy Market so the definition name has been changed.

[14] "Distributed energy resource" [or DER] means any geographically dispersed energy resource located on an electric distribution system that produces electricity or offsets electrical demand including small generator facilities, energy storage devices, energy efficiency devices, and demand response devices. While not specifically specified in COMAR 20.50.09.02B, the definition of DER does not exclude devices including but not limited to smart thermostats, other smart home devices or appliances (hot water heaters, pool pumps etc.), DLC switches, rooftop solar, electric vehicles, batteries etc.

[15] OPC proposed definition

(12) “Homogenous VPP” means a VPP consisting of only injectable or only curtailment resources[16].

(13) “Injectable resource” means a DER which transmits electric energy on to an EDC’s electric grid[17].

(14) “PJM DER Aggregator Participation Model” means the framework for VPPs to participate in the PJM Interconnection LLC energy, capacity, and/or ancillary services markets.

(15) “PJM VPP” means a VPP that is dispatched in response to a PJM Interconnection LLC direction in the PJM DER Aggregator Participation Model. A PJM VPP may also be dispatched by an EDC or a DERA to an EDC’s direction for distribution grid services provided there is no double counting of compensation.

(16) "Renewable on-site generating system" has the meaning stated in Public Utilities Article, §7-1001(I), Annotated Code of Maryland.[18]

(17) “Retail Tariff Participation Model” means the EDC framework for VPPs to provide electric distribution grid services through either an electric company tariff or a contract between the electric company and the DERA.

(18) “Virtual Power Plant” or “VPP” has the meaning stated in Public Utilities Article, §7-216, Annotated Code of Maryland. and maybe either an EDC VPP, a Retail VPP, a PJM VPP or a single component DER. A “VPP” has the same meaning as a “DER Aggregation Resource” in the PJM DER Aggregator Participation Model.[19]

[16] OPC proposed definition

[17] OPC proposed definition

[18] Potomac Edison suggests that renewable on-site generating systems also be referred to as “intermittent generation” to align with FERCs definition of DER.

[19] Tesla recommended adding a definition for a “DER Aggregation Resource" to mean a collection of one or more Component DERs that are operated as a single asset. DER Aggregation Resources are designated by a DERA, and may include smaller DER Aggregation Resources so long as each Component DER is only listed once.” However, since the DRIVE Act defines VPP we should not adopt the PJM definition, but this accommodation is made in the VPP definition to indicate a VPP is the same as a “DER Aggregation Resource.” This also requires defining PJM DER Aggregator Participation Model and changing numerous other references in the regulations.

20.50.13.03 DERA Licenses

A. DERAs. A DERA that participates in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model shall be licensed by the Commission using a process determined by the Commission. Once a DERA has been licensed, it may register component DERs and VPPs with an EDC pursuant to Regulation .05 of this Chapter.

(1) All licensed DERAs shall be subject to a Code of Conduct pursuant to Regulation .13A of this Chapter.

(2) If the Commission has reason to believe a Code of Conduct violation has occurred, either based on its assessment or a complaint received, it shall investigate and provide the opportunity for a hearing.

(3) If, after a hearing, the Commission determines that a violation has occurred, it shall enforce the Code of Conduct and may consider corrective action plans, civil penalties, suspension, and forfeitures of a DERA license.

B. EDC DERAs. An EDC that acts as a DERA does not need a DERA license from the Commission but is subject to Code of Conduct compliance as described in Regulation .13B of this Chapter.

(1) If the Commission has reason to believe a Code of Conduct violation has occurred, either based on its assessment or a complaint received, it shall investigate and provide the opportunity for a hearing.

(2) If, after a hearing, the Commission determines that a violation has occurred, it shall enforce the Code of Conduct and may consider corrective action plans or civil penalties.

20.50.13.04 DER Registry

A. Each EDC shall maintain a DER Registry to be a single record of DER and VPP information that will facilitate the provision of grid services for both retail tariffs and PJM LLC wholesale markets, as applicable.

B. Maryland-licensed DERAs participating in PJM LLC wholesale markets shall have access to all PJM required information to which they are entitled pursuant to PJM tariffs that is held exclusively by the EDCs by January 1, 2028.[20] EDCs are not required to provide information to DERAs participating solely in the PJM DER Aggregator Participation Model that is not required by PJM tariffs or that is considered Critical Energy/Electric Infrastructure Information (CEII) data pursuant to 18 CFR § 388.113.[21]

C. Maryland-licensed DERAs participating solely in the Retail Tariff Participation Model shall have access to all applicable EDC information necessary to enroll VPPs in applicable retail tariffs. EDCs are not required to provide information that is not required to enroll VPPs in applicable retail tariffs or is considered Critical Energy/Electric Infrastructure Information (CEII) data pursuant to 18 CFR § 388.113.[22]

[20] Per Order No. 92398, Maryland-licensed DERAs shall have access to all PJM required information held exclusively by the EDCs by January 1, 2028, regardless of whether the registry is centralized or implemented EDC-by-EDC. This may require the EDCs to enable such access prior to the final iteration of any registry. As part of Roadmap development, the DEWG should outline how DERAs will receive information access by January 1, 2028, while maintaining data privacy and security, even if such access is an interim step on the way to a final registry implementation. The Commission directs the DER Registry Roadmap to be filed within six months of the issuance of this Order.

[21] Some clarifications have been made at the request of the Sierra Club to make it clearer.

[22] Some clarifications have been made at the request of the Sierra Club to make it clearer.

D. At a minimum,[23] a DER Registry shall include the following information, if applicable, for each component DER registered in a DERA:[24] [25] [26]

(1) Unique EDC DER Identification Number

(2) DER Type[27]:

[23] These requirements are intended to be common among all utilities. Utilities may have their own DER Registry requirements.

[24] Exelon proposed this change.

Sierra Club strongly disagrees stating that "the intent of the registry was to capture all DERs. This change completely changes the applicability and design of the DER registry. This will mean that the registry will only include DERs included in DERAs, which is a very limited subset for planning and operational purposes. In addition, this will essentially mean that the EDCs will not have to change their current DER databases to conform to a DER registry standard."

While the Workgroup Leader does not disagree that ideally all DERs should be in a DER Registry, this only sets a minimum requirement for the purposes of initially implementing VPPs which is the purpose of this regulation.

Tesla agrees with Sierra Club that this is a total reversal of policy, but is sympathetic to the EDCs that creating such a registry would be herculean. For export resources, like batteries, it should be straightforward; for thermostats, V1G, and other flexible loads, that would be insane. Battery aggregators generally don't need registry information since they are managed by their OEM or installer (although in the long run, business churn would make a registry useful to re-engage stranded assets). All this to say, that Tesla supports the current iteration for the sake of practicality.

[25] Per Exelon's comments, At some point in the future, the Workgroup should revisit this list after the North American Standards Board (NAESB) implements their DER Registry data requirements. It is premature to do this now until NAESB standards are implemented.

[26] Exelon recommends we use language like this from the NJ draft requirements: "Each EDC shall each develop a DER registry. The DER registries of all the EDCs shall have a consistent structure with common data fields and definitions. The EDCs shall jointly develop and propose this structure. Development of the DER registry may consider what categories of data DERs actually have available and are willing to publicly share (e.g. are not proprietary or otherwise confidential). Key registry fields may include, but are not limited to:" This was not accepted as we need all stakeholders involved in proposing this structure, not just the EDCs. Sierra Club states that "At the minimum, we advocate for a consistent structure and with common data fields and definitions. Application of this structure to all utilities is a minimum requirement. The only change [to Exelon's language recommendation] would be not adopting the "EDCs shall jointly develop and propose this structure." SC does not believe that the EDC should be the arbiters of this structure and it should be open to stakeholder input."

While not opposed, the Workgroup Leader has not included the Exelon or Sierra Club language since the proposal of a structure is not a regulation, but a recommendation that should be pursued after the Data Exchange Work Group completes its work on a DER Registry framework.

[27] Potomac Edison recommends that if the state of MD would like to use DER type metering, then there will be a need for device type identification for each DER type.

(a) Solar

(b) Wind

(c) Energy storage

(d) Demand response

(e) Energy efficiency[28]

(f) Vehicle to Grid (V2G)[29]

(g) Managed Charging Electric Vehicles (EVs) [30]

(3) PJM Market Resource Designation for PJM VPPs Only[31]

(a) Generator Resource

(b) Energy Storage Resource

(c) Demand Response Resource

(d) Energy Efficiency Resource

(4) DER Location:

(a) Premise Address

(b) EDC meter number

(c) Applicable EDC device level meter number

[28] This data should be consistent with how energy efficiency is handled in PJM's DR Hub.

[29] Electric vehicles can act as an injectable resource with vehicle-to-grid (V2G). Tesla recommends replacing Bidirectional Electric Vehicles (EV) with Vehicle-to Grid to reduce confusion and align with the terminology used in the IX regs, it is likely easier to call these V2G systems so that when we say EVs we're really talking about managed charging of EVs.

[30] Electric vehicles can act as a demand response resource (i.e., curtailing EV charging on demand)

[31] OPC recommended addition.

(d) Utility Electric Distribution Locational Data including but not limited to Substation, Feeder Number, Line Segment Identifier and Distribution Transformer Location Codes and Node Location Codes, if applicable.[32]

(d) Electrical Node[33]

(e) PJM Pricing node for PJM VPPs Only

(f) Geospatial coordinates for PJM VPPs Only[34]

(5) DER Segment Type[35]:

(a) Behind the Meter Distribution

(b) Front of the Meter Distribution

(c) Front of the Meter Transmission[36]

(6) DER Performance Characteristics

(a) DER kW approved

(b) DER nominal voltage

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[32] Exelon asks how this will be used? Exelon also notes that in the current NAESB draft DER Registry standards, the Substation, Feeder/circuit, and Phase data elements are: a) Noted to be provided only during the aggregation registration process (not for all DERs on the system), and b) Are proposed to be removed in the latest redlined draft of the DER Registry standard as of Sept 4, 2026. Exelon also notes that this requirement may violate CEII. Workgroup Leader Response: See the addition to .04B and .04C in response. Sierra Club states that "Exelon is mischaracterizing NAESB's status. The redline that they are referencing is a counter-proposal that [we] perceive to not be the committee's consensus."

[33] Needs more discussion on how this is identified for EDC and PJM. OPC recommends replacing with Feeder and Substation identifiers. SC agrees that a discussion is needed, especially for Retail VPPs and DRIVE Act VPPs, and can support OPC's recommendation for its precision.

[34] Sierra Club questions Why only for PJM? EDCs would also benefit from GPS information of DERs to identify location on the distribution system.

[35] Exelon requests these terms be defined.

[36] Sierra Club questions if a DER is connected at Transmission, which would indicate that it is a transmission resource or generation connected at transmission voltage. Hence, not a distributed resource.

(c) DER inverter model and serial number

(d) IEEE 1547-2018 inverter settings[37]

(e) Maximum output raising and lowering ramp rate, or in the case of an energy storage DER, the maximum charge and discharge rate.

(f) Normal raising and lowering ramp rate, or in the case of an energy storage DER, the normal charge and discharge rate.

(g) Minimum notification times required if manually dispatched

(7) Grid Services Tariff Enrollments for both PJM Interconnection LLC Tariffs and Retail Tariffs[38]

(8) DER Contact Information

(a) Company Name, if applicable

(b) DER Address

(c) Primary Contact Name

[37] Exelon asks for clarification on what this means? How would this be applied to individual DER components in a DER Registry? The EPRI DER Settings are default settings applicable to all DERs for our system. Workleader Response: The intent is to cover inverter data requirements for the individual settings like ride-through settings etc. as established in the Electric Power Research Institute DER Performance Capability and Functional Settings Database. It is my understanding that except for +/- a dozen settings, utilities do use the defaults so the intent is for the database structure to include all the EPRI data fields for each inverted but to only replace items that do not use the defaults in the DER Registry. Also we can't incorporate the EPRI database by reference since it is not recognized as a standard and the Maryland Incorporation by reference manual only allows standards to be referenced since the standard carries the same authority as a regulation.

Sierra Club states that "An additional reason to include this in the registry is to capture the difference in inverter vintages. For inverters installed before IEEE 1547-2018 was adopted in MD, this would either be null or the ride-through settings that were required before the adoption of the new standard." The Workgroup leader responds that old inverters installed prior to January 1, 2024 are grandfathered and not required to upgrade to a smart inverter pursuant to COMAR 20.50.09.06O so they would not necessarily have any inverter settings.

[38] Potomac Edison is seeking clarity on whether a DER can offer multiple retail tariff services and also be in multiple distribution service aggregations due to component DERs being allowed in multiple PJM DER Aggregations.

(d) Primary Contact Email address

(e) Primary Contact Telephone number

(9) DER Mapping to a DERA and VPP

(a) DERA Name

(b) VPP Identification Designation[39]

(10) Any PJM DR Hub Data Requirements not specifically otherwise specifically required in Regulation .04D, if necessary for DERs participating in PJM LLC wholesale markets.[40]

[39] Needs further discussion of what this means?

[40] The previous item (10) have been replaced with a "catch all" for DR Hub as we have no control over how PJM expands its collected data.

20.50.13.05 VPP Review

A. VPPs may be composed of a minimum of a single component DER, or alternatively consist of a combination of either homogeneous component DER types or heterogeneous component DER types. VPPs must be at least 100kW, and individual component DERs may not exceed 5MW. The size of a VPP shall be measured on their one-hour capacity,[41] energy, or ancillary services offered into the PJM DER Aggregator Participation Model or the Retail Tariff Participation Model, based on the physical and operational characteristics of their underlying component DERs. There is no minimum size requirement for individual "Component DERs" within a VPP.

B. A PJM VPP shall exist behind a single pricing node with an exception that permits multi-nodal aggregations across one EDC territory and PJM Interconnection LLC transmission zone in cases where component DERs cannot aggregate to a minimum of 100 kW within a single PJM pricing node.

(1) Multi-nodal aggregations must comprise one or more Component DER with capability smaller than 100 kW, unless the total capability of all other Component DER in an aggregation is below the 100 kW participation threshold[42].

(2) In a multi-nodal aggregation, one Component DER or group of component DERs less than or equal to 100kW at a single PJM pricing node shall be permitted.

(3) The multi-nodal cap will be 167 MW, subject to EDC review and adjustment once greater than 90% of the cap is reached.

(4) An exception is allowed by PJM for multi-nodal aggregations for PJM VPPs providing ancillary services only with no single pricing node limitations.

[41] Tesla is not entirely opposed, but it is worth discussing how this determination interacts with any caps/limits that are imposed. If this is fully open ended, that's fine, we just need to remember that the multi-hour deliverable capacity will be lower than this #.

[42] OPC asks can an example of this be provided for clarity? It is unclear as to when this would occur.

C. A Retail VPP or EDC VPP participating in a Retail Tariff Participation Model shall be permitted to have multi-nodal aggregations across a single EDC territory consistent with the Retail Tariff Participation Model requirements.

D. EDC Review Criteria. An EDC shall use applicable technical interconnection requirements criteria for System Impact Studies specified in Chapter .09 of this subtitle in the reliability review of VPPs. All Component DERs shall be studied by the EDC in accordance with the DER's interconnection request[43] if applicable and any flexible interconnection options previously approved by the EDC pursuant to COMAR 20.50.09.06P.

E. EDC Review Process[44] [45]. The EDC review process for a VPP shall include:

(1) A maximum 60 calendar[46] day timeframe for EDC review including any incremental reviews:[47]

(a) Upon registration of all component DERs in a VPP and submission of all related DER data as specified in Regulation .04, the EDC will have up to 15 calendar days to review the information provided for registration completeness, data accuracy, and retail/wholesale double-counting protections and indicate that the information is complete and the DERs are capable of participating in the

[43] In several places in this Regulation, BGE has suggested inserting "intent of generation" but this suggestion seems to be BGE specific terminology for a BGE process so it was not accepted.

[44] Tesla proposes that prior to accepting applications for an EDC, PJM, or DERA VPP, EDCs shall announce a dispatchable range for the VPP, as applicable. DERAs submitting VPP ranges that the EDC cannot reliably accommodate on a normal basis shall be deemed non-compliant. BGE has expressed opposition stating that "VPP limits may be dependent on the Retail Tariff Participation Model, the aggregation being asked for, etc."

[45] Tesla wants to flag this resource:
https://www.iso-ne.com/static-assets/documents/100033/final_dera_registration_process.pdf

[46] In several locations, BGE proposed replacing calendar days with business days but this was not accepted because PJM's FERC Order 2222 compliance filing is based on calendar days.

[47] Wording was requested by BGE to apply existing COMAR regs to incremental reviews: 5-day completeness review, and then 15-day Tech Review for Level 1's and 20-day Tech Review for Level 2 and above. This will ease processing at the EDC. However, this was not accepted because FERC rules require that when an aggregator modifies an existing DERA (such as adding or removing a component DER), any incremental review of those modifications is similarly bound to the maximum of 60 calendar days to complete its technical, safety, and reliability review of a DERA registration. FERC explicitly ruled that EDCs cannot use open-ended or prolonged timelines for incremental changes.

VPP.

(b) Following the first 15 calendar day review, if the registration information is not complete or inaccurate the DERA may adjust the registration submission including the DER Resources comprising one or more component DERs[48] and the EDC review process restarts.[49] [50]

(c) Following a determination of registration completeness for a VPP the EDC will have up to 45 calendar days to perform a reliability review of the aggregation to ensure there are no violations of EDC reliability[51] review criteria.[52]

(2) When approving an EDC or Retail VPP, or recommending approval of a PJM VPP, EDCs shall approve a dispatchable range[53] for the VPP, if applicable.[54] DERAs may alter the component DERs in response to such a limit.[55]

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[48] Tesla proposes that after the 15 day EDC review, component DERs that are not approved shall be given the opportunity to address shortcomings related to eligibility of specific component DERs within 15 business days without resetting the 60 calendar day EDC review period.

[49] Tesla proposes this addition. Tesla still supports the underlying point, but wants to point out that this is now longer than the 60 day period. This is only applicable if the EDC rejects some resources and the DERA needs to cure info related to those DERS. A way to rectify this is in Tesla's redlines

[50] Tesla suggests making this a subbullet of (a) and renumbering the remaining items. Also this item replaces the former (e): " If a DERA modifies a list of DER resources in a VPP after initial registration, the EDC review timeframe may reset and begin again if more time is required by the EDC for VPP review.

[51] Tesla proposes this addition.

[52] Tesla states that it would be great to get a definition on this. Workgroup Leader notes that new RM94 regulations in 20.50.09.02B require: "Technical interconnection requirement" or "TIR" means a public-facing document available on an electric company's website that specifies interconnection technical review criteria and distributed energy resource functional settings and an electric company's Level 4 analysis template.

Sierra Club states that "While the Sierra Club would prefer that the Commission clearly identify these criteria or set guiding principles, we can live with clearly stated criteria and templates. However, what is missing is clarity on how aggregations of DERs will be analyzed. Is that covered in the RM94 regulations?" Workgroup Leader Response: The RM94 regulations require that interconnection technical review criteria be documented in a TIR, we do not prescribe how utilities perform their analyses in regulations at this time.

[53] Workgroup question: Does dispatchable range only apply to the whole VPP and not for individual DERs in a VPP? Workgroup Leader Response: It can apply to both and this has been modified in the definition.

[54] Potomac Edison is asking for clarification on what determines applicability in this instance. Potomac Edison would also like to understand why this is not applicable to all VPPs and only DERAs. Workgroup Leader Response: The applicability may vary depending on the tariff and VPPs are synonymous with DERAs in this regulation.

[55] Tesla questions if this would send it back to the beginning of the 60 day process? It also risks risks creating a conflict with the following section (3). Workgroup Leader Response: Under PJM's framework for FERC Order 2222, modifying the component Distributed Energy Resources (DERs) in an aggregation during the review process does not restart or extend the maximum 60-day review period. The FERC explicitly ruled that 60 days is the

(3) Following the EDC's review process approval, PJM has a 15 calendar day window to deliver the final approval or denial for a PJM VPP.

(4) After EDC review, DERAs shall be given 60 calendar days[56] to address VPP shortcomings[57] related to review failures or the dispatchable range.[58] [59]

(5) If a DERA cannot address shortcomings[60] within the 60-calendar day redress period, the VPP will not be approved or not recommended for approval to PJM by the EDC, with a reason for the recommended denial given in writing to the DERA by the EDC.[61]

(6) If a DERA can only address shortcoming with an interconnection upgrade, the EDC shall offer to perform a feasibility study at DERA cost and within a mutually agreeable timeframe.

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absolute maximum timeframe allowed for Electric Distribution Companies (EDCs) to complete their safety and reliability assessments. Section (3) has been modified accordingly.

[56] Tesla proposed addition.

[57] OPC asks are there situations in which a VPP would raise reliability concerns that would be curable, but only on the VPP level and not by changing interconnection standards for any of the DERs? How does this work for demand response, which does not interconnect as a generator under 20.50.09.06

[58] Tesla wants to reiterate this.

[59] Tesla states "I think we either need to take this approach, (a) where it's 60 days of review, 60 days to cure, a new 60 days to review again or the approach contemplated earlier where it's a series of 15 day increments where EDC and DERA confer at the end of each step. I would like the 15 day version but the 60 day version might be more realistic.

[60] Tesla states there is a gap in the regulation where if the DERA can address shortcomings, then they'd be resubmitting a revised application to the EDC but the EDC has no more time to review it. That ambiguity implies that the denial and associated failures/dispatchable range issues must be presented in such a way there is an unambiguous path to rectification; I am afraid this creates a situation in which either side can use the expiration of the clock to force the other side to accept their view of the aggregation. Tesla thinks the answer would be to start another round of review process (ideally the 15 day version, but maybe 30 to split the difference) but [the Workleader's comment] implies that would be impermissible under FERC rulings. I think this will back the situation into a corner where the outcomes are:
1) accepted on first reliability pass
2) denied with very specific parameters that must be agreed to by the DERA (I would guess removing component DERs, making targeted reductions to dispatchable range) else final denial is eminent
3) denied with unrealistic conditions (major reduction in dispatchable range or paying for infrastructure upgrade) leaving no hope of overall approval
Given Tesla's reading of your understanding of the FERC rule, I don't think there is a solution here and we must hope for a productive relationship between DERAs and EDCs.

[61] Potomac Edison suggests that written denial occurs through the DER registry, like how it will be addressed in the PJM DER Hub.

(7) For a VPP or Component DER that is recommended for denial as part of the VPP review process, a DERA may bring the dispute to the Commission for resolution pursuant to Regulation .10 of this Chapter.

E.[62] EDC Incremental Review. An incremental review focuses only on a targeted review of the new or added impact of a Component DER's participation in a VPP, rather than re-studying the entire group of resources. An EDC shall review the incremental impacts from a component DER participating in a VPP as follows:

(1) An EDC shall not necessarily conduct a full, exhaustive restudy of an VPP or the individual component DERs that were previously reviewed unless the previously reviewed proposed operation of a component DER or VPP is modified.

(2) If a VPP proposes to add a new Component DER or materially modifies the proposed operation of an existing Component DER in a VPP an EDC shall review the incremental impacts from a component DER participating in a VPP that was not previously considered by the EDC during the VPP review process.

(3) When a DERA submits modifications to its Component DERs during an incremental review, the 60-calendar day EDC review process restarts.

F. Double Counting

(1) An EDC shall review the plans of the VPP to participate in both Retail Participation Models and PJM DER Aggregation Models. An individual VPP shall only be compensated in the Retail Participation Models and PJM DER Aggregation Models for distinctly different services to ensure no services are double counted.[63]
(2) An EDC shall consider the following with respect to double counting of VPP compensation:

(a) Program Rules:

[62] This was moved from Section C at Tesla's suggestion since it fits better after the EDC review.

[63] NineDot questions if utilities have the ability to track PJM vs. Retail Tariff participation for comparison may rely on the DER registry. Potentially until there is a DER registry DERAs can only enroll as Retail participating OR PJM. PHI responds that it "will be [utility] responsibility to track for DERA registration in PJM. I don't think DER Registry is the dependency."

(i) Net energy metered DERs shall adhere to PJM Interconnection LLC tariff rules with regard to participation in and compensation from VPP grid services.[64]
(ii) Other program rules as directed by the Commission when approving EDC programs or PJM Interconnection LLC tariff rules.

(b) Time Rules: VPPs may provide similar grid services in both Retail Participation Models and PJM DER Aggregation Models provided that these Services are not provided at the same time.[65]

(c) Capacity Rules[66]: DERAs may split DER assets in a VPP between different grid services by identifying the individual Component DERs participating in each grid service.

(d) Post-Hoc Rules[67]: DERAs that are determined by the EDC to have incurred double counting of compensation shall have their compensation adjusted through

[64] Tesla and Voltus support this provision. Voltus also supports adding a qualifier that was not adopted that states "or where the output of an energy storage DER is separately measured with a device level meter or inverter data and netted out of Net Energy Metering settlement."

[65] Exelon states PJM has some requirements that state changes in registrations for DERAs can't take place within the same year. A specific time-based allowance could create confusion and conflicts as it relates to participation in various markets and tariffs. Tesla wants to push back against the idea that the level of granularity for the term 'time' should be annual, as the Exelon comment implies. The intent of this section is to allow a resource to be compensated for performance just hours apart, which is technologically feasible and could be accounted for under BAAJA rules. Note: The Bipartisan American Affordability and Jobs Act of 2026 (BAAJA) establishes a federal framework allowing behind-the-meter (BTM) resources and Virtual Power Plants (VPPs) to participate in wholesale electricity markets while strictly prohibiting "double compensation."

[66] Exelon states that this section could create a lot of confusion. If VPPs are allowed to participate in markets and programs on a Component DER by Component DER basis, why are they registered as an aggregation? For example, if a utility has both an EV and a thermostat program and a VPP is enrolling the component DERs into the two different programs, it may become very difficult for us to track enrollment, participation, and then provide payment to the DERA. Tesla pushes back on Exelon's comments here. Location-dependent or other dynamic aggregation tools are already on the horizon and this provision will help make this regulation forward looking. They're right that in the current landscape, it would make more sense for the differently-behaving devices to be in two separate aggregations, which most will. However this landscape, and the EDCs' ability to manage flexible aggregations, will evolve. Additionally, this provision would not include assets enrolled in currently-constructed EDC programs; this is for DERA aggregations who are participating outside of existing program structures - that Exelon example is off base.

[67] Solar United Neighbors does not like post-hoc rules that give primacy to wholesale vs.retail tariffs. However, the PSC can't influence wholesale tariffs at the state level. Post-hoc rules are needed for the PSC Consumer Affairs Division to arbitrate disputes, rather than letting this play out and leaving these rules undefined at this time.

post-hoc transaction accounting that prioritizes PJM Market Participation Model compensation over Retail Tariff Participation Model compensation.

(3) EDCs shall raise concerns regarding double counting of grid services related to a VPP during the first 15 calendar day review period and recommend rejection or revision, as appropriate.

G.[68] VPP approval shall not be effective until the DERA has executed any of the following applicable agreements:

(1) A PJM Interconnection, LLC DER Aggregator Market Participation Service Agreement, if applicable.

(2) Any EDC tariff approvals, or executed EDC agreements associated with a Retail Participation Model, if applicable.

(3) Any interconnection agreements for all applicable component DERs that inject power into the grid pursuant to Chapter .09 of this subtitle.

H. Multiple component DERs that exist in a proposed VPP that are behind a single point of interconnection may be aggregated into one interconnection request[69] subject to interconnection requirements in COMAR 20.50.09.

[68] Sierra Club states that this provision is trying to carry too much water. SC wonders if this is only for PJM VPPs. Even if it is meant to be for VPP approval, PJM VPP approval requires both (1) and (3). Similarly, a DERA or EDC VPP probably needs both (2) and (3), depending on the answer to our question about (2). It may be cleaner to create specific rules for each type of VPP. Tesla "Generally agree[s] with Sierra Club's input, but don't think it really matters if this section exists or not. Saying that an approval isn't effective until the conditions of the approval is met seems to be implied. I would err on the side of removing entirely, but if it is to stay in, just make sure to keep all the 'if applicable' part to defer to the contracts/tariffs eventually developed.

[69] There is no such thing as a VPP interconnection agreement but this allows multiple DERs at a single location to be considered in one interconnection agreement as long as they are in a VPP since the impact to the system is from the VPP, not each component DER. This may reduce utility processing.

20.50.13.06 Metering and Telemetry

A. A component DER in a PJM VPP shall meet existing PJM Interconnection, LLC settlement metering requirements.

B. EDCs shall propose metering configurations for future grid services programs and retail tariffs on a case-by-case basis.[70]

(1) EDCs shall evaluate and report to the Commission on the feasibility of using device level metering and submetering in any VPP program proposal.[71][72]

C. PJM VPPs shall comply with applicable PJM telemetry requirements.

D. EDC-proprietary broadband shall not be the only option provided by EDCs for communication with DERs and EDC VPPs.[73] An EDC shall specify telemetry requirements for

[70] In Order No. 91603, the Commission directed the IWG, "to propose future regulations that will provide a framework for device-level metering to be utilized in the future, subject to acceptable accuracy requirements needed for billing and settlement." The Commission recognizes that these regulations are still in development and will be informed by DRIVE Act DSSS pilot outcomes as well as additional investigation into metering and submetering technologies." In Order No. 92398 the Commission directed "the IWG to further examine metering and submetering technologies. We leave the creation of a subteam to the IWG's discretion."

[71] Sierra Club objects to this provision stating that "a number of device level metering provisions were deleted from Ver 9 and this was inserted instead. Order No 92398 calls on the IWG to form a subteam. This provision ignores that direction and stakeholder involvement and gives EDCs the full evaluation and reporting role. A subgroup should be formed and it will be tasked with recommending language here." Sierra Club further states that "This provision leaves too much discretion to EDCs. A standard set of metering configurations should be created." Workgroup leader response: Yes a subgroup is being formed, but this language is current Commission direction in Order No. 91603. PHI Recommends adding "a clarifier in here around proposing after learning have come in from the DRIVE pilots. If we anticipate other pilots/programs that will require an evaluation and report on device level metering and submetering, that will be duplicating work over and over while we complete the submetering pilot approved in the DRIVE order." Tesla further states that "This still feels unfinished, but I think it's okay to punt and wait for DRIVE learnings. We have not met about telemetry and submetering which would inform. Maybe we add some intent language that points towards using the most economical means possible for ensuring necessary accuracy?"

[72] Limiting or hindering EV onboard telemetry and communication in addition to device level metering in EV chargers, DER inverters and battery management systems may add costs to VPP programs and utilities should consider using suitably accurate devices to the extent possible.

[73] In Order No. 92398, the "Commission supports flexibility and agrees with stakeholders that IEEE 2030.5 should not be mandated. However, EDC-proprietary broadband should not be the only option for communication with small

EDC VPPs and DERA VPPs.

(1) These telemetry requirements shall specify scan rates and applicable kW size of component DERs and VPPs for applicable tariffs.

(2) EDCs shall utilize communication protocols compatible with IEEE 1547-2018 or subsequent revisions, or other accessible methods such as DNP, Modbus, API Access, or IEEE 2030.5.

DERs, and the IWG should develop regulations to that effect. The Commission supports Staff's recommendation that the Exelon Utilities and Potomac Edison should continue testing IEEE 2030.5, and the Commission directs these EDCs to provide regular updates to the IWG on testing outcomes, with reporting cadence to be determined at the discretion of the IWG Leader. The Commission affirms that directives on communications protocols will govern EDC communications with Aggregators and not Aggregator communications with DERs, but regulations should allow the EDCs to communicate directly with devices if those devices are enrolled in an EDC-managed VPP and not enrolled in a third-party aggregation."

20.50.13.07 Operations Coordination

A. A DERA is responsible for scheduling and dispatching the component DERs in compliance with EDC provisions in applicable retail tariffs or PJM Interconnection LLC requirements, as applicable.

B. On a prescribed basis as defined in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model, EDCs and DERAs shall coordinate the range of MW dispatch per hour for the VPP as specified in applicable PJM Interconnection LLC requirements or retail tariffs.

C. On a prescribed basis as defined in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model, EDCs and DERAs shall also coordinate planned maintenance and other work that will impact dispatchability of a component DER as specified in applicable PJM Interconnection LLC requirements or retail tariffs.

D. On a prescribed basis as defined in the Retail Tariff Participation Model or in the PJM DER Aggregator Participation Model, EDCs and DERAs shall coordinate operations on planned system conditions requiring updated bid parameters or overrides to maintain reliability that may result from, but are not limited to, unplanned outages, abnormal feeder configurations, safety, or load beyond forecasted expectations as specified in applicable PJM Interconnection LLC requirements or retail tariffs.

E. Updated bid parameters and overrides are abnormal and shall be tracked by the EDC for later investigations and potential dispute resolution[74].

F. An EDC may override the physical operation of a VPP when EDC reliability criteria is violated.[75]

(1) EDCs shall communicate overrides using communications methods as specified in

[74] Potomac Edison is asking for clarification on how EDCs will track these. Will the commission lay out a standard process for tracking bid parameters and overrides.

[75] Sierra Club's proposed language was accepted. Exelon states that Sierra Club's proposed changes are much more rigid than the originally suggested language. The original language supports BGE's operational responsibility, but language should preserve utility discretion for safety, reliability, etc. VPP dispatch (and more importantly halting dispatch for safety purposes) may be challenging if we are required to provide extensive documentation and reasoning prior to overriding VPP dispatch. An after the fact response and analysis feels more appropriate and would allow for the utility to maintain a "big red button" in case of emergency.

applicable PJM Interconnection LLC or retail tariffs before the fact for reliability concerns affecting the scheduling and dispatch of VPPs.

(2) EDCs shall provide a written explanation of the overrides using communications methods as specified in applicable PJM Interconnection LLC or retail tariffs to the extent possible before the fact for reliability concerns affecting the scheduling and dispatch of VPPs.

(3) EDCs shall use communications methods as specified in applicable PJM Interconnection LLC requirements or retail tariffs prior to real-time operation or dispatch when directing an override for reliability concerns affecting the dispatch VPPs.

(4) EDCs shall provide a written explanation using communications methods as specified in applicable PJM Interconnection LLC requirements or retail tariffs when directing an override for reliability concerns affecting the dispatch VPPs, as soon as practical afterwards.

G. An EDC shall provide notification to the DERA at least 30 calendar days in advance of executing a permanent load transfer and update the DER registry when the transfer affects the electrical node and PJM Interconnection LLC pricing node information, if participating in PJM Markets.[76] Load transfers made for emergent system needs are exempt and notification will be provided should the transfer be made permanent.[77]

[76] Sierra Club requests that this be further explained. Workgroup Leader Response: Permanent load transfers are made routinely that change the circuit or substation from which a DER is connected. This requirement was added under the assumption that this would be something a DERA would want to know since it may affect their participation in PJM markets.

[77] BGE proposed changes are reflected in this revision.

20.50.13.08 Information Sharing Requirements

A. Information sharing requirements for electric utilities and DERAs shall be required as determined by the Commission.[78] [79]

[78] The legal authority for a regulation in the Code of Maryland Regulations (COMAR) to leave a standard or requirement "as determined by the Commission" comes from the Maryland Administrative Procedure Act (State Government Article, § 10-101 et seq., Annotated Code of Maryland) and the Public Utilities Article § 2-112 enabling statute that grants the Commission its broad legal jurisdiction and general powers over public service, utility, and motor carrier companies operating inside Maryland.

[79] In Order No. 92398 the Commission established a new Data Exchange Work Group (DEWG) to draft regulations and parameters for implementation of a state-wide GBC compliant data exchange platform. First, the DEWG shall draft regulations for third-party access to customer data and file these draft regulations within six months of the issuance of this Order for a rulemaking. The final regulations should ensure that, at minimum, Maryland licensed DERAs have customer-authorized access to customer data, but the DEWG should consider eligibility for additional third parties to maximize use cases and benefits. Second, the DEWG shall develop, within six months of the issuance of this Order, criteria for a request for proposals ("RFP') to develop, implement, and, if necessary, maintain a GBC-compliant data exchange platform that enables permission-based sharing of customer usage and appropriate customer-identifying information. The DEWG should consider PJM requirements when determining which customer-identifying information to include. The platform should incorporate the pillars of data privacy, customer authentication and authorization, data standardization, and third-party registration and onboarding, and it should be certified periodically by the Green Button Alliance, at a cadence to be determined by the DEWG. The RFP criteria shall promote a secure, customer-friendly experience with the platform. To that end, the DEWG should consider allowing third parties to initiate requests for customer authorization and data sharing, as well as the possibility of native authorization. Native Authorization allows customer authorization directly within a third-party application instead of requiring multiple log-ins.

20.50.13.09 Retail Tariff Participation Model

A. A VPP and all component DERs shall be located within the service area of one EDC.

B. PJM VPPs shall be subject to applicable PJM Interconnection LLC tariff provisions in addition to any applicable EDC retail tariff participation provisions.

C. EDCs providing tariffs for DERA VPPs and EDC VPPs shall address the following, as applicable[80] [81] [82]:

(1) Measurement and verification methods.
(2) Dispatch requirements and method of communications
(3) Duration and acceptable time windows for dispatch events.
(4) Technical parameters upon which a curtailment would occur.
(5) Penalty provisions for non-performance, including unavailability, if applicable
(6) Tariff rates for compensation for the specified grid services
(7) The provision of a performance-based and/ or an up-front reservation payment, as applicable.[83]
(8) A clear process for performance-based settlement and customer and/or aggregator payment[84]
(9) Collection of data by the EDC that is required for managing and evaluating grid services and for evaluating performance and/ or availability.
(10) Nodal aggregation limits for a VPP

[80] Potomac Edison recommends including system injections by desire. Tesla would like clarity on what PE means by "by desire" for injections. I would argue that they should be explicitly allowed in line with the IX agreement.

[81] Various clarifying edits proposed by OPC and Tesla in this section.

[82] Voltus proposes adding two extra items below that were not adopted due to their late submission without the benefit of Workgroup consideration.

(11) The distribution or transmission grid services being compensated and how they differ from services compensated in PJM markets.
(12) How dispatch windows account for hours that set PJM Peak Load Contributions, to the extent dispatch in those hours would reduce a VPP's PJM capacity value.

[83] EnergyHub recommended edits

[84] EnergyHub recommended edits

D. VPP participation in grid services shall accommodate the physical and operational characteristics of an aggregation without placing restrictions on resource or technology types for market participation and shall allow both heterogeneous and homogeneous VPPs to participate in all PJM Interconnection LLC markets and EDC tariffs where they can provide grid services.[85] [86]

E. Provided that VPP performance and availability requirements are met and there is no double-counting of grid services pursuant to Regulation .05 of this Chapter, nothing in this Chapter shall prevent a VPP from enrolling in grid services.[87]

[85] OPC recommends deleting this section.

[86] Question from PHI: (1) Does this contradict anything from PJM around double counting? (2) DRIVE as intended only for "clean" generation right? Would this be in violation "without placing restrictions on resource or technology types" Workgroup Leader Response: DRIVE is being implemented without regulations and is focused on specific types of VPPs whereas these permanent regulations need to allow for all potential types of VPPs and technologies, including non-clean technologies. This does not negate the double counting requirements in Regulation .05

[87] Exelon recommends removing as this statement is broad. This chapter is defining what's required for a VPP to participate and this statement reads as redundant.

20.50.13.10 VPP Dispute Resolution

A. A dispute may arise between for many reasons involving component DERs, DERA and EDCs.[88] If the dispute involves component DER due to local reliability or Retail Tariff Participation matters, the dispute falls under Commission jurisdiction. If the dispute involves a PJM Interconnection LLC matter, the dispute falls under PJM jurisdiction.

B. The DERA, component DER and EDC shall attempt to resolve all grid services disputes as provided in this regulation promptly, equitably, and in a good faith manner.

C. Dispute Resolution Before the Commission.

(1) If a dispute arises that cannot be resolved, the component DER, DERA, or EDC may seek immediate resolution through the procedures of COMAR 20.50.09.13.

(2) Dispute resolution shall be conducted in an informal, expeditious manner to reach resolution with minimal costs and delay.

(3) PJM Interconnection, LLC non-performance penalties may apply to a DERA when a PJM VPP does not perform because an EDC overrides PJM's dispatch.[89]

D. Pursuit of dispute resolution may not affect a component DER or VPP behind a single point of interconnection with regard to consideration of an interconnection request or an applicant's queue position.

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[88] Potential areas for dispute include, but are not limited to:

(1) Override decisions for reliability, safety, or other needs by the EDC

(2) Choice of component DERs and DERA assets subject to overrides by an EDC

(3) Compensation to DERAs

(4) Data submission discrepancies between EDCs and DERAs

(5) VPP or component DER recommended denials by an EDC

(6) Denials of DER Registry data to an authorized participant

(7) Purported violations of the regulations in this chapter

(8) Device level metering denials

(9) An EDC's determination regarding the necessity of an incremental review

(10) An EDC's determination regarding double counting

[89] OPC recommended addition

E. Any deadline imposed by the regulations in this chapter, which is directly affected by any issue in dispute, shall be suspended until resolution of the dispute unless prohibited by PJM Interconnection LLC requirements for a PJM VPP.

F. If a satisfactory resolution is not achieved between the parties, the DERA or EDC may request a hearing pursuant to Public Utilities Article, Annotated Code of Maryland § 3-102.

20.50.13.11 VPP Review Fees[90]

A. EDCs shall specify VPP request fees[91] to be charged under this regulation in its tariffs to reflect additional EDC administrative costs[92] incurred for review and approval of VPPs. These fees shall reflect costs prudently incurred by the EDCs for reviewing the eligibility of component DERs and studies to determine the reliability impacts of a proposed VPP.

[90] Sierra Club states that this section needs a lot of work. Its single provision states that EDCs can charge fees. There is nothing on the justification or prudency of these fees, nor the categories of fees and their cost justification. At the minimum, additional provisions and necessary justifications need to be established by Commission processes for approving these fees. Workgroup Leader Response: All fees must be approved by the Commission in a tariff where the utility justification will be analyzed by Staff and OPC, among other parties that may want to comment.

[91] Potomac Edison is seeking clarification on whether the administrative costs include additional EDC metering and or wheeling charges for PJM DR if determined applicable.

[92] Exelon supports the addition of costs to stand up the technology as well as the costs to administer once it's in place.

20.50.13.12 VPP Reporting Requirements

A.[93] Annually on or before April 1, an EDC shall provide the following information for the previous calendar year in a report filed with the Commission:

(1) Number of new DERA operating in each EDC's service area for the preceding calendar year.

(2) Number of VPPs approved during the preceding calendar year segmented by EDC VPP, DERA VPP for both PJM VPPs, and non-PJM VPPs.

(3) Number of VPPs denied during the preceding calendar year segmented by EDC VPP and DERA VPP for both PJM VPPs, and non-PJM VPPs.

(4) For each VPP approved during the preceding calendar year segmented by EDC VPP and DERA VPP for both PJM VPPs, and non-PJM VPPs, the capacity by DER Registry type as defined in Regulation .04 of this Chapter.

(5) Number of EDC real-time overrides of component DERs annually for the preceding calendar year segmented by EDC VPP, DERA VPP and PJM VPP.

B. Cumulative Totals. Annually on or before April 1, an EDC shall provide the cumulative totals since a tariff's effective date for the information in Regulation .12A.

[93] OPC's recommendation for various editorial changes were accepted in these latest edits.

20.50.13.13 Codes of Conduct

A. DERA Code of Conduct.

1. Applicability. This code of conduct applies to any DERA that engages customers and their resources to participate in VPPs.

2. Consumer Enrollment. DERAs shall ensure that any representations including verbal statements, advertising, and sales materials are accurate and current and do not intentionally deceive customers into making decisions under false pretenses.

3. Training[94]. DERA sales staff shall be properly trained to communicate accurately to customers and shall behave in a manner that does not deceive, pressure, or harass potential customers.

4. Consumer Protection. DERAs shall adhere to all applicable consumer protection laws and regulations and comply with all federal and state antitrust laws and regulations regarding anti-competitive behavior.[95]

5. DERA Proposals. Grid services proposals shall be fair and accurate and shall not deceive customers. All relevant benefits of these proposals must be clearly described, any fees clearly and thoroughly explained, and grid services requirements clearly presented to customers. DERAs shall provide the customer with a thorough written proposal before a contract is signed. At a minimum, the services proposal shall include:

a) Full detail of the confirmed and potential benefits under the terms of the

[94] Potomac Edison is seeking clarity regarding who would be training DERA sales staff, and what documentation is necessary for training.

[95] BGE proposed additional language involving only contacting customers who have opted-in. Since PC79 is handling this matter these changes were not accepted.

agreement;

b) Performance requirements for the customer and potential penalties for non-performance;

c) A clear and transparent statement of the operational parameters under which the customer will be dispatched;

d) Financial estimates; and

e) A detailed quotation.

6. Contracting. A customer shall be presented with a standard grid services contract form that clearly states the terms and conditions and that also makes the customer aware of their share of benefits, risks, liabilities, and obligations. Before the customer enters into a grid services contract, a DERA must, in writing:

1. Inform the customer that they are entering into a legally binding contract; and
2. Inform the customer if they have obligations for performance penalties and provide details on these legal obligations. Performance penalties shall not exceed actual costs borne by the DERA due to the non-performance[96].
3. Operational constraints on the dispatch of Component DERs shall respect customer health and safety before and during operational dispatch and during extreme weather events, and shall be incorporated into the operating parameters or opt-out provisions of the grid services contract.
4. DERAs shall clearly explain what technologies shall be used in the provision of grid services including any constraints on the use of a consumer's resource and the role and responsibilities of the participating customer. This includes providing customers with visibility regarding how their resources will be controlled individually and as part of a larger aggregation, if applicable.
5. Customers shall be provided with information regarding their ability to override or opt out of an operation action, if applicable, as well as any costs they would incur, if applicable, for doing so[97].
6. Customers shall be provided with information regarding the role of regulatory oversight by the Commission and all applicable rules and

[96] OPC recommended addition.

[97] OPC recommended addition.

standards.

7. The DERA must inform each participating customer of information concerning the conditions of use of customer information and explicit customer permissions.
8. The DERA must inform each participating customer of the terms under which the customer can leave an aggregation, and shall not impose any charges or penalties for leaving an aggregation greater than the actual costs incurred[98].
9. Upon request by the Commission or an EDC, a DERA shall provide evidence of executed contracts.

7. Operations.

a) Participating customers shall be provided with adequate notice[99] before operational actions are necessary to ensure participating customers have an opportunity to take appropriate action.
b) DERAs shall provide participating customers with clear and periodic feedback[100] on the customer's performance in providing grid services.

8. Complaints. DERAs shall provide customers with a procedure and system for registering complaints and resolving disputes. The procedure will address the process steps and the timing to resolve a customer complaint, including the steps a customer can take if they are unable to resolve the complaint, including filing a complaint with the Commission.

9. Privacy. DERAs shall comply with their obligations under applicable consumer data protection laws in the collection and processing of personally identifiable information (PII) and other sensitive consumer data. In addition, DERAs shall

[98] OPC recommended addition.

[99] BGE questions "Does anyone have a pulse on what will be considered adequate notice? DRIVE models will be 21-hour notice to the aggregator for planned events but closer to no notice for an emergency need. Should we request to add something about "when possible for emergency response needs".

[100] BGE questions what periodic means?

adhere to the U.S. Department of Energy (DOE) DataGuard Energy Data Privacy Program Voluntary Code of Conduct[101].

10. Cybersecurity[102]. DERAs shall take appropriate measures to manage cyber risks, consistent with applicable cybersecurity frameworks and standards to ensure the security of their systems and communications and information interfaces with consumers' devices and to provide proper responses in the event of a system failure.

11. Record Keeping. DERAs shall supply all relevant customer records to the Commission, upon request. DERAs shall keep a record for a minimum of three years:

a) All of the written information provided to a customer during a sales visit, including but not limited to printed or electronic sales communications with customers that they or their representatives make.
b) Information on a requested operating action related to a customer and the customer's performance.

[101] OPC wants to add a provision that a DERA shall not share or sell PII to other entities, and shall not use PII for purposes other than DERA operations and marketing. However, it is unlikely that a DERA will have access to PII and if needed, an EDC would require an NDA anyway so this is not recommended.

[102] OPC asks if this can reference cybersecurity regulations or some other standard?

B. EDC Code of Conduct[103] [104] [105] [106] [107]

[103] Per BGE comments and discussion at the August 18 IxWG meeting, we need to explore overlap with COMAR 20.40 on affiliate regulations

[104] OPC proposed this section addition. In a similar vein Sierra Club offered the following comments: We would recommend language along the following lines which General MicroGrids proposed for the IWG's consideration:

"Based on Maryland Public Service Commission Guidance containing detailed safeguard requirements for market protection, and consistent with operating in the public interest, an EDC that acts as a DERA or is affiliated with a DERA shall take appropriate steps and measures to ensure open market access to other market participants, including third-party aggregators, and to avoid and prevent discriminatory market conditions arising out of conflicts of interest, abuse of market power, non-disclosure of material market information or lack of appropriate transparency, or other practices that would advantage the EDC in market transactions and operations;

To implement this Section, the Maryland Public Service Commission shall develop and issue Guidance to EDCs to ensure that any EDC which is operating in the public interest will provide open market access to its distribution facilities to other market participants and that the EDC shall not create, support or further any discriminatory market conditions arising out of conflicts of interest, abuse of market power, non-disclosure of material information or lack of appropriate transparency, or other practices that would place the EDC at an advantage in market transactions and operations. In this regard, this Guidance document shall take into account and reflect best practices in the electric industry and include, without restriction, such elements as, detailed safeguard requirements relating to conflicts of interest, abuse of market power, non-disclosure of material information, etc.; principles; required measures and steps for an EDC to take to establish procedures and training for its personnel; and compliance standards for assuring appropriate transparency in market transactions and operations."

[105] Following the discussion at the August 18 IWG meeting, the [Exelon] utilities have mapped each provision of Part B against COMAR 20.40 (Electric and Gas Companies, Affiliate Regulations). The utilities recommend that Part B be removed from the VPP Draft Regulations and that the provisions worth retaining be adopted as amendments to COMAR 20.40. Under this approach, VPP Regulations would retain the DERA Code of Conduct in Part A and would contain no provisions regulating EDC conduct. Three reasons are as follows:

1. First, COMAR 20.40 already regulates the conduct Part B addresses: preferential treatment and selective information sharing (20.40.02.01), contemporaneous disclosure of system and delivery information to market participants (20.40.02.03D), shared personnel restrictions (20.40.02.04), and cost allocation between the utility and its affiliates (20.40.02.05 and .07). Adopting Part B as drafted would regulate the same conduct in two chapters under different definitions and separate enforcement paths.

   General MicroGrids noted that COMAR is dated and should be re-examined for updating, appropriate modifications; and addressing "Gaps" that arise in the context of not only VPP-specific organization and implementation, but also within the larger context of Retail Market development and operations in Maryland, consistent with MD's deregulation statutory requirements (e.g., addressing conduct more broadly than disclosure of information, information sharing, etc in COMAR 20.40, but also addressing new relevant issues that relate, among other things, to how any EDC (whether or not with an "affiliate" DERA/VPPs or one operating as an EDC VPP) will function in the "Public Interest" within the context of

1. Code of Conduct. Each EDC shall maintain policies, procedures and safeguards for ensuring a fair and transparent grid services market

(a) Each EDC's policies and procedures shall address each of the principles in .13B-2

(b) Each EDC's policies and procedures shall align with best practices in the electric industry, including with respect to setting standards for compliance, safeguard requirements and accountability.

(c) Each EDC's policies, procedures and safeguards shall reference and build upon applicable State and Federal laws and regulations, including COMAR 20.40.02, regarding unfair, discriminatory or anti-competitive

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Retail Market Development and Operations in Maryland which is a deregulated jurisdiction. Based on legal precedents established in evolving the organized power markets, as well as State best industry practices, the development of Retail Markets in which VPPs will participate, including EDC VPPs, necessitates not just the current Code of Conduct provisions, but new provisions and Commission Guidance that require proactive and specified preventive measures and steps, taking into account an EDC's role in owning and operating a regulated Utility Distribution System in the public interest and proposed significant responsibilities and decision-making authority with respect to both helping to develop such Retail Markets, as well as coordinating and harmonizing with Wholesale Markets. Mapping to the current, "Affiliate" provisions of a dated Code of Conduct does not sufficiently address the scope nor the breadth of such new roles, responsibilities and decision-making authority.

2. Second, the provisions in Part B are freestanding prohibitions, while the corresponding provisions in 20.40 are tied to compliance mechanisms: an annual Cost Allocation Manual, officer affidavits, training certification, and Commission audit access (20.40.02.07 and .08). Relocation attaches the provisions to enforcement machinery that already exists.

3. Third, the approach follows the Work Group Lead's stated preference at the August 18 meeting for adapting 20.40 rather than recreating codes of conduct already codified in COMAR.

One provision in Part B, the lead-in to B.2, does not map to 20.40 because it imposes an obligation to guarantee market outcomes rather than a conduct rule; the utilities' proposed replacement language for that provision appears in the comment at B.2.

[106] Voltus supports adopting the EDC Code of Conduct with these regulations rather than deferring it, and recommends that it continue to apply to EDC VPPs operated in-house as well as through affiliates, since COMAR 20.40 covers affiliates only.

[107] General MicroGrids noted that these "Code of Conduct" issues extend beyond the "Affiliates" provisions of COMAR 20.40 (e.g.,Utilities have indicated they are addressing organizing "VPPs" within the Utility itself); and also raise issues for any EDC within the context of retail market development in Maryland. These matters, therefore, need to be addressed more broadly.

conduct by Maryland regulated utilities.[108]

2. Each EDC shall take reasonable actions to maintain the fairness and transparency of the grid services market within their service territory, including measures designed to prevent abuse of market power, lack of appropriate transparency, non-disclosure of material information, preferential treatment in disseminating or sharing information, and other practices and/or conduct that could provide any DERA an undue competitive advantage.[109]

(a) An EDC shall provide equal access of information[110] to all market participants. When authorized to do so, an EDC will share third-party information to all parties equally and contemporaneously.

(b) An EDC shall conduct fair market operations for grid services, without preference for any VPP offering, including open market access to its distribution facilities.

(c) An EDC shall not give preference with respect to interconnection, registration, or dispatch to any VPP offering.

(d) An EDC shall establish and maintain a mechanism for dispute resolution that requires written responses to complainants and allows for meetings with complainants and their right to seek Commission review.

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[108] General MicroGrids supports "integrating" the proposed EDC "Code of Conduct" provisions into COMAR generally, not just the "Affiliates" provisions; however, these provisions make clear that COMAR will need updating and modification to address specifically standards for compliance, safeguards and accountability in connection with "VPP" organization/implementation and "MD Retail Market Development," including consideration of the need for MD Public Service Commission Guidance that takes into account applicable State and Federal laws and regulations, industry best practices, and especially other jurisdiction "models" that have addressed similar circumstances (e.g., NY Public Service Commission's "Reforming the Energy Vision" Initiative ("REV") and the NYPSC's approach to updating their applicable existing Code of Conduct and the other steps the NYPSC implemented)

[109] Exelon states that "Independent of location, the lead-in to B.2 should not be adopted as drafted in either chapter. As written, it makes each EDC responsible for ensuring the fairness of the grid services market in its territory, which includes the conduct of DERAs and other third parties the EDC does not control. That is an obligation to guarantee market outcomes rather than a conduct rule, and no conduct regulation in COMAR imposes an obligation of that kind."

[110] Per BGE comments, "Would working through an implementation partner/grid-edge DERMS who is dispatching the EDC VPP to increase participation be an information advantage? In existing programs, do target marketing to high propensity customers? Not having that direct marketing ability introduces burdensome complexity with program implementation."

(e) An EDC, also coordinating with other EDCs, shall establish adequate procedures and annual training for its personnel to ensure compliance with this EDC Code of Conduct.[111] [112]

[111] This was not an OPC proposal but was lifted from an earlier version of DERA licensing requirements.

[112] General MicroGrids noted that EDC Code B provisions make clear the newness, importance and complexity of these issues and the need to dedicate commensurate time and process to addressing them. These do not merely "overlap" current COMAR 20.40.02. General MicroGrids urges a rulemaking proceeding with notice and comments, especially in light of the proposed scope and breadth of the roles, responsibilities and decision-making authority contemplated for Maryland EDCs just within these proposed VPP Regs, in order to prohibit, prevent, as well as to penalize, unfair, discriminatory and anti-competitive conduct and practices. In this stakeholder's view, this will require more than the "general Affiliates" provisions currently in COMAR. In fact, in this stakeholder's view, these issues compel clarification and MDPSC Guidance to assure that any EDC does not gain an undue competitive advantage as Maryland's Retail Market is emerging, as well as to assure a fair and transparent Retail Market for all market participants. Issues, especially raised by BG&E (e.g., using the DRIVE Act EDC Pilot as a Permanent Model; and addressing potential conflicts of interest where an EDC is working through a partner/Grid Edge DERMs that is dispatching the EDC VPP or the EDC's affiliated VPP, etc.) make clear the newness, importance and complexity of these matters. Finally, how the values reflected in this "EDC Code of Conduct" and the current Code of Conduct are addressed need to take into account and be consistent with all of the relevant MDPSC Orders, steps and measures being taken, including for example a "statewide" data exchange platform, as envisioned by the Commission.