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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

TRACK 4 PROPOSAL OF SUNRUN INC., CALIFORNIA ENERGY STORAGE ALLIANCE, CALIFORNIA SOLAR & STORAGE ASSOCIATION, TESLA, INC., CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES, VOTE SOLAR, AND ENEL X NORTH AMERICA, INC.

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Pursuant to the December 11, 2020 *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling* ("Track 4 Scoping Memo"),[1] Sunrun Inc. ("Sunrun"), California Energy Storage Alliance ("CESA"), California Solar & Storage Association ("CALSSA"), Tesla, Inc. ("Tesla"), Center for Energy Efficiency and Renewable Technologies ("CEERT"), Vote Solar, and Enel X North America, Inc. ("Enel") (collectively, the "Joint Parties")[2] hereby submit this Track 4 Proposal ("Proposal") addressing further refinements to the Resource Adequacy ("RA") program.

I. Introduction

This Proposal falls under item 4 in the Track 4 Scoping Memo: *Capacity values for Behind-the-Meter (BTM) hybrid storage/solar resources. On November 24, 2020, a joint agency workshop was held between the Commission, CEC, and the CAISO, as directed by D.20-06-031. The workshop covered the steps necessary to establish capacity values for BTM hybrid storage/solar resources*.[3] Within this Proposal, the Joint Parties incorporate aspects of a

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1 R.19-11-009, *Assigned Commissioner's Amended Track 3B and Track 4 Scoping Memo and Ruling* (December 11, 2020) ("Scoping Memo").

2 The Joint Parties have authorized Sunrun Inc. to file this Proposal on their behalf.

3 Scoping Memo, p. 8.

proposal made in Track 3A of this proceeding by Tesla, CESA, Sunrun, CEERT and Enel.[4] This Proposal focuses primarily on the instant issue in this proceeding—establishing a qualifying capacity ("QC") value and dispatch requirements for behind-the-meter ("BTM") hybrid and standalone storage resources. This Proposal also presents two pathways for supply side RA participation by BTM resources.

The California Public Utilities Commission's ("CPUC" or "Commission") joint agency workshop in November revealed that adequately achieving the objective of provision of capacity by BTM resources, and effectively implementing FERC Order 2222,[5] will require many issues to be addressed and resolved outside the scope of this docket. Thus, this Proposal focuses both on the specific issue in scope for this proceeding—a QC value for BTM hybrids and BTM standalone storage based on the full output of the resource—*and* on several other issues that must be scoped into other dockets. Whether the resolution of these issues is directly within the scope of this docket or not, these issues are certainly within the scope of the workshop held in November 2020, as directed by a decision within *this* proceeding.[6]

The Joint Parties emphasize that proposals to establish capacity values and address barriers to realizing their capacity deliveries must be addressed in Track 4 of this proceeding. The Joint Parties are aware of other proceedings that are currently underway in which the Commission is considering BTM hybrid solar and storage resources to provide reliability services, such as the Emergency Load Reduction Program ("ELRP") in R.20-11-003.[7] However, these and other related efforts do not supplant the need to provide a long-term sustainable virtual power plant ("VPP") market with consistent rules and processes that govern how these BTM hybrid solar and storage resources provide reliable capacity services. Regarding the immediate and relevant efforts in R.20-11-003, any resources "procured" through the ELRP are proposed by Energy Division staff as "out of market" and thus not incorporated in the RA planning

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4 R.19-11-009, *Resource Adequacy Track 3.A Proposal of the California Energy Storage Alliance, Sunrun, Inc., Enel X North America, Tesla, and Center for Energy Efficiency and Renewable Technologies Pursuant to the Assigned Commissioner's Amended Track 3.A and Track 3.B Scoping Memo and Ruling* (September 1, 2020) ("Track 3A Proposal").

5 *See* FERC Order No. 2222, 172 FERC ¶ 61,247 (September 17, 2020) ("FERC Order No. 2222").

6 *See* D.20-06-031, pp. 32-33.

7 R.20-11-003, *Administrative Law Judge's Ruling Introducing a Staff Report and Questions to the Record and Seeking Responses from Parties in Opening and Reply Testimonies*, Attachment 1: Final Staff Proposals and Guidance to Parties, pp. 5-6 (December 18, 2020).

framework.[8] This is appropriate given that R.20-11-003 aims to address emergency reliability needs that are above and beyond the current RA requirements, and has framed the ELRP as being triggered and dispatched for emergency conditions, particularly during extreme heat-storm events such as those experienced in August and September 2020. Rather, as part of Track 4 of R.19-11-009, the Joint Parties seek to establish a capacity framework that fairly values and operationalizes the contributions of BTM resources to RA needs on a regular basis, akin to other RA resource types.

This Proposal prefers a market informed pathway for provision of supply-side RA capacity for BTM resources. The Joint Parties recommend that the Commission continue the discussion and consideration from the November 2020 workshop to create a market informed pathway for these resources. This pathway was described as "Pathway C" by the Energy Division at the workshop. This Proposal also presents proposals specific to modifying and operationalizing the current participation pathways—Proxy Demand Response ("PDR") and Distributed Energy Resource Provider ("DERP")—for market-integrated resources.

The Joint Parties urge the Commission to not require distributed energy resources ("DERs") to pursue or favor one pathway over the other. Given the urgency and need to provide clean, local, and distributed capacity, the Commission should instead enable multiple pathways for DERs to deliver RA capacity, whether as a market-integrated or market-informed resource. Responses to questions and topics raised at the November workshop are woven throughout this Proposal, in the relevant sections.

II. Pathways: Market Informed and Market Integrated

There are two primary pathways for event-based BTM resources to participate in "supply side" RA solicitations, both of which were discussed at the November 24, 2020 workshop. For purposes of this Proposal, the Joint Parties refer to these pathways as market informed and market integrated—categories that are discussed in more detail in the following sections. While these pathways do not share equally in the breadth of regulatory reform required to actualize them, the immediate need for a QC value is a barrier they share.

8 In testimony submitted in R.20-11-003, all parties either proposed to have ELRP resources operate or count as RA resources.

A. Market Informed Pathway

A market-informed resource is one that is not directly integrated into the California Independent System Operator ("CAISO") wholesale market, but its dispatch "triggers" are informed by the market. This pathway was defined as "Pathway C" in the Energy Division's presentation. Market-based triggers can include, but are not limited to, market heat rate, market price, reserve margin, stage emergency, etc. To be clear, the Joint Parties do not necessarily advocate that BTM resources only be dispatched in the case of grid emergency. BTM hybrids and BTM standalone storage are capable of providing local, reliable clean energy on a regular basis.

The best example of the market-informed pathway is the crediting for RA value of investor-owned utility ("IOU") demand response ("DR") programs prior to bifurcation and for certain types of DR programs after bifurcation. For example, programs like Critical Peak Pricing ("CPP") are clearly "event-based" programs in the sense that they are centered around discrete events informed by market conditions, but CPP is not actually bid into the CAISO market. It is an "event-based, market-informed" DR program that is nevertheless afforded RA capacity value through the Load Impact Protocol ("LIP") evaluation process.[9]

All BTM resources providing capacity should have the option to forgo market integration, as the market-informed pathway is simpler and avoids a number of obstacles that have impeded third-party DER providers from bringing DR resources into the CAISO market. This is for a number of key reasons including, but not limited to, the following:

1) Issues surrounding interconnection of exporting resources are eliminated as Rule 21 clearly governs based on the current tariff structure and rules.
2) Complexity and cost associated with market integration and dispatch are also eliminated, as the aggregator dispatches the resource in accordance with predetermined criteria.
3) Issues associated with visibility at the transmission-distribution interface, necessitating communication and visibility of resource performance by both the distribution operator and the CAISO, are also eliminated.

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[9] *See, e.g.*, R.13-09-011, *SCE's Compliance Filing Pursuant to Load Impact Protocol Filing Requirements* (April 1, 2020).

4) Any concerns associated with double payment for electricity from net energy metering ("NEM") systems—wholesale market revenue for settled resource export, and retail bill credits for NEM—are eliminated.
5) Resource aggregators are better able to dispatch resources to meet specific local needs, rather than relying entirely on system-level CAISO dispatch, which may be inconsistent with local needs.
6) The thorny issue of deliverability to the transmission system is avoided entirely.
7) Most DERs are interconnected under Rule 21, and the only CAISO tariff for these resources is PDR, which does not credit energy exported to the grid.

B. Market Integrated Pathway

The market integrated pathway is currently required for DER resources that wish to offer capacity into request for offers ("RFOs") for RA issued by load-serving entities ("LSEs"). DER resources are required to participate in the CAISO market and be subject to a must-offer obligation. Technically, a resource may participate in the market via either the DERP or PDR models. At present, the PDR model severely undercuts the contribution of BTM hybrids and storage, and the DERP is not functional given a number of issues that must be resolved. As the Commission itself acknowledged in comments filed with the Federal Energy Regulatory Commission ("FERC"):

> DERs are participating in the CAISO wholesale market as behind-the-meter demand response (DR) resources, using either the proxy demand response (PDR) or reliability demand response resource (RDRR) participation models . . . Given that these models are solely for demand response, and do not allow for export of energy to the wholesale market, they are limited.[10]

In addition to the issues within this proceeding, as discussed earlier in this Proposal, the Joint Parties strongly recommend that the CPUC coordinate with the CAISO, resource providers, and the utilities to resolve issues and barriers to the market integrated pathways. Close coordination and proactivity on the CPUC's part to address these issues and barriers is crucial if the agencies wish to facilitate full implementation of FERC Order 2222. The Joint Parties

[10] FERC Docket No. RM18-9-000, *Post-Technical Conference Comments of the California Public Utilities Commission*, pp. 3-4 (June 26, 2018) ("CPUC FERC Comments").

discuss barriers to each market pathway—PDR and DERP—below, followed by a discussion of several key issues, including: interconnection, coordination between transmission and distribution operations, and establishing rules permitting BTM storage resources to charge at wholesale if performing a wholesale service.

Proxy Demand Response Resource

Under the currently operational market integrated PDR model, DER discharge is limited by the onsite customer load, which artificially caps the amount of capacity that can be provided, even as the BTM hybrid or storage has additional capacity that could be otherwise exported to the grid. Ironically, the failure to recognize and credit exported energy in PDR acts as a disincentive for facilities with batteries to practice conservation during times of grid stress since reducing onsite load further reduces the amount of energy that can be credited to the storage device in programs like the Demand Response Auction Mechanism ("DRAM"). Finally, for facilities with low minimum daily loads, like homes and schools, the export constraint can effectively prevent participation by these customers, since the minimum daily load—which aggregators would need to bid at in order to avoid violating the must-offer obligation given the export constraint—might be too low to offer meaningful RA value.

With over 400 MW of customer-sited energy storage online, significant stranded export value could be unlocked from existing systems to provide critically needed capacity for future grid emergencies and to support the replacement of retiring generation capacity. While there are technical interconnection limits that prevent the delivery of this stranded export capacity from existing storage systems (*i.e.*, some storage resources may have been interconnected as non-exporting systems), existing storage systems can adapt, and new storage projects can be developed and configured in ways to harness export capabilities if exports are valued for RA capacity.

Distributed Energy Resource Provider

FERC's recent Order 2222 directs independent system operators ("ISOs") and regional transmission organizations ("RTOs") to create market participation pathways for DERs, including BTM resources, to participate in wholesale markets. This Order was modeled in part off of the CAISO's DERP model, which was first created in 2016 but is not used today. The first issue is the lack of a QC methodology for these resources. Other key issues include interconnection processes, incrementality, and resource visibility, and many fall either entirely or partially in the jurisdiction of the CPUC.

The CPUC has acknowledged some of the steps necessary to actualize DERP resources within California. In comments to the FERC in Docket No. RM18-9-000, the docket that ultimately resulted in FERC Order 2222, the CPUC stated that "[b]ased in large part on our experience in establishing market participation rules and processes for demand response resources, at a minimum the local regulatory authority, ISO/RTO, DER provider, and UDC should all be involved in the coordination process to facilitate market participation of DERs."[11] The CPUC went on to acknowledge that "[s]tate regulator roles are likely to include, at a minimum: modifications to associated rules governing procurement by electric utilities, state-jurisdictional interconnection rules, and resource adequacy counting and rules; establishing measurement metering and enforcement rules; approving utility procurement; and establishing cost effectiveness guidance for utilities."[12] Finally, in these same comments, the CPUC acknowledged a list of barriers to DERP participation, which included interconnection, QC value, and a requirement for DERP resources to be settled in all hours.[13]

Despite these numerous barriers, the Joint Parties urge the Commission to begin addressing many of these issues given that the non-generator resource ("NGR") model already recognizes and enables the full range of load reduction and export capacity of DERs to provide capacity and readily allows for the delivery of certain wholesale market products (*e.g.*, ancillary services). However, in addition to the lack of a QC value, which should be addressed in this proceeding, the inability to differentiate the wholesale versus retail cost for charging and exporting energy has persistently prevented BTM storage from participating in the NGR model. Even with Order No. 841 directing the CAISO to address this issue in their compliance filing, the CAISO simply indicated that it will zero out BTM storage resources' charges for wholesale charging through its settlement software where the utility distribution company ("UDC") is unable to net out wholesale energy purchases from its billing.[14] While compliant with Order No. 841 in not double billing customers with both wholesale and retail charges for the same charging energy in response to a wholesale market price signal, it essentially deferred this issue to the

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11 CPUC FERC Comments, p. 7.

12 *Id.*

13 *Id.*, p. 4.

14 172 FERC ¶ 61,050, P 28 (July 17, 2020).

Commission and the IOUs to develop a means to differentiate wholesale and retail charging energy.

III. Qualifying Capacity Value and Dispatch Requirements

A primary barrier to BTM hybrids and standalone storage resources providing RA today is the lack of a QC methodology for these resources, beyond those used for traditional demand response resources, and the lack of corresponding availability and dispatch requirements, thus making these resources ineligible for RA. This issue is common to the market integrated and market informed pathways. Within this section, the Joint Parties also respond to the following questions posed by Energy Division in the November 2020 workshop:

- *Should battery export (negative load) be included in the capacity value?*
- *How should capacity value be measured during an event?*
- *Are current Load Impact Protocols (LIPs) adequate to establish ex-ante capacity valuation of BTM S+S VPP resources?*

The Joint Parties recommend that the CPUC leverage the same QC methodologies for BTM hybrids and storage as those used for their equivalent resources interconnected in front of the utility meter ("IFOM"). This would set the baseline QC, from which operational capacity (*e.g.*, outages to provide distribution-level or resiliency services, for example, if CAISO market integrated), among other considerations, could be assessed. Especially as the Commission now reflects the effect of BTM resources in its capacity valuation of its IFOM counterparts, such as is done for solar, the RA value of BTM resources should be explicitly credited in QC methodologies, and should reflect the full output of the resource, including any exports. With direct metering and measurement of the storage resource, this is especially true as the storage behind the customer meter would operate no differently under must-offer obligation and/or dispatch requirements from a similar system that is located several blocks away on the utility side of the meter. The only difference is that the former may be discharging to serve its onsite customer first and then exporting to the grid, whereas the latter would be discharging to serve all customers, among which include the said onsite customer. Functionally, customers will be equally served by the same storage whether onsite or in front of the meter.

The capabilities of IFOM and BTM hybrids and storage may also not be different, even if the BTM resources are subject to retail rate structures that reflect, in much less granularity, the generation mix and other retail cost drivers. The same logic applies for standalone storage systems, whether IFOM or BTM, where the applicable RA counting rules (*i.e.*, four-hour maximum continuous output) should be justified. It is incumbent on the resource operator to adhere to the RA requirements and be subject to any RA program or CAISO market rules that may impact the resource's capacity rating. However, it stands that the forward capacity determination should be set equally as a starting baseline for BTM resources as it is done for its IFOM counterparts.

Year-ahead QC for BTM hybrids and storage should be set based on contracted capacity. While contract capacity is not necessarily the same as installed capacity, setting the QC on contract capacity is appropriate for BTM hybrids and storage since there is assurance that the forward-looking QC amount is backed by real, physical capacity. DER aggregators would be "on the hook" to actually demonstrate their contracted capacity in their response to events, and face penalties for shortfalls. A resource's QC could then be adjusted based on actual performance in response to tests or dispatches. Battery export, in addition to customer load modification, should be included in the capacity value, and measured based on the actual submetered response to an event. The Joint Parties advocate for the use of measurement-based approaches to validating capacity values, whether through tests, CAISO market dispatch, or market-informed LSE dispatch—whichever approach or combination of approaches are applicable for the RA pathway for BTM resources. Wherever BTM energy storage and hybrid resources are able to be directly submetered or measured using an inverter, such direct measurement approaches should be utilized.

LIPs, as they are currently applied and interpreted by the CPUC, are not adequate for the purpose of setting *ex ante* capacity values for BTM hybrids and storage. The LIP methodology employed by BTM resources is limited by the export limitations of the PDR market participation model. It is not known how the LIP would be interpreted and applied for resources that do not face the same constraints—either for DERP resources or those not integrated into the market under a market informed model. Fundamentally, the predictable, controllable and dispatchable nature of BTM storage resources necessitates a change to the current approach to BTM resource valuation, and should obviate the need to use the LIP. BTM storage can uniformly modify customer loads independent of behavior or weather driven effects, making it possible to reliably estimate capacity contribution over all relevant time periods—hours, days, months—and is directly metered.

The Joint Parties question the continued use of LIPs for several other reasons as well. First, the LIP was created in 2008 for an entirely different purpose, prior to bifurcation and prior to BTM storage market development, and was applicable to IOU DR programs and not third-party managed resources. While the Energy Division has worked to streamline the process, it still suffers from a lack of transparency and clarity that other supply-side resources do not face when establishing their capacity value. Further, there is no clear way to protect DR aggregator data, as this particular scenario does not fall cleanly within any of the CPUC's existing confidentiality rules.[15] The Joint Parties recommend either jettisoning the use of the LIP entirely for third parties with BTM resources, or interpreting the LIP as permitting a QC value assignment based on submetered battery performance, inclusive of export.

IV. Must-Offer Obligation & Dispatch Triggers

These two issues—must-offer obligation for market-integrated resources and dispatch triggers for market-informed resources—are closely related. For market-integrated resources, whether using the PDR or DERP models, the Joint Parties recommend a must-offer obligation that requires the resource to be available during Availability Assessment Hours ("AAH"). It is during these hours that BTM storage and hybrid resources provide the most value to the grid. For market-informed resources, the Joint Parties recommend dispatch triggers designed for specific conditions, including day ahead economic trigger and a real time/day of operational trigger based on grid needs that cannot be anticipated in the day ahead time frame. Dispatch triggers for market-informed resources could include: state of CAISO emergency, local reliability events, and average market price. Advance knowledge of potential dispatch is preferred so as to enable scheduling of optimal battery cycling and guarantee sufficient battery state of charge ("SOC") to respond to the market dispatch.

At the November workshop, the Energy Division posed the following questions with regard to dispatch triggers for market-informed resources:

- *What requirements should apply to VPP dispatch trigger mechanism?*
- *Is the resource under a requirement to perform when called upon?*

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15 *See* D.06-06-066.

- *Are there penalties for failing to perform?*

As discussed above, the Joint Parties distinguish the RA proposals and developments herein from those related to the ELRP. For RA to be used and useful, and to take advantage of the fast-start, frequently dispatchable, and flexible capabilities of BTM hybrids and storage, it may be appropriate to consider the establishment of a dispatch trigger that reflects these intended goals. For example, to mimic supply-side BTM storage under either the PDR or DERP models, the Commission and the CAISO could assess historical data to determine what appropriate dispatch trigger prices could be established for particular months or seasons to guide market-informed performance from the 4-9pm period, or other periods of need.

Dispatch trigger mechanisms should also allow for predictability to the extent possible. In order to allow storage resources sufficient time to ensure they are charged and ready for full dispatch, the Joint Parties recommend dispatch triggers be set on a day-ahead basis. This could be achieved by using prices or expected heat rates in the day-ahead market as a trigger mechanism.

In addition, dispatch conditions must contain clear performance requirements. Just as IFOM resources face penalties for failing to deliver on a must-offer obligation, it makes sense to assign reasonable penalties to DERs receiving capacity credit if those resources fail to perform.

V. Incrementality - SGIP, NEM, Forecast

The Joint Parties see a major need for the Commission to establish a universal incrementality framework to determine RA procurement eligibility and to fairly and accurately assess QC value. Importantly, incrementality must be defined and assessed consistently across the different Commission proceedings.

In R.14-08-013, for example, a Ruling was issued in 2020 that adopted new incrementality language to be used in distribution deferral solicitations: "as long as the project commits to meeting the dispatch requirements described in the protocol and pursuant to the [technology neutral pro forma] . . . SGIP projects that provide an incremental service will be considered fully incremental."[16] Additionally, in R.14-10-003, a Proposed Decision was recently issued that addressed incrementality by differentiating between incentives for technology

[16] R.14-08-013, *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements*, pp. 76-77 (May 11, 2020).

deployment and payments for services.[17] Taken together, the Commission has recognized the differences between incentives and payments for the provision of services, which should inform the incrementality rules developed within the RA planning framework. Finally, while it is important to ensure that resources are not double counted in the forecast, this is an issue of accounting and planning, rather than one of double compensation.

At the November 2020 workshop, the Energy Division posed the following questions related to this topic:

- *How should the VPP capacity value be counted in the RA/CEC planning framework?*
- *How should the VPP capacity be handled in the annual process for determining local RA requirements and allocation to LSEs?*
- *How should potential double counting issues be resolved?*

In addressing these questions, the Joint Parties propose an incrementality framework that values and compensates VPP capacity from: (1) a planning and procurement perspective; and (2) an operational and performance evaluation perspective. By viewing incrementality along these lines, many of the discussions around double counting and double compensation become clearer and can be applied differently to the market-integrated versus the market-informed model.

First, planning and procurement incrementality involves an *ex ante* determination of how much capacity and energy of a resource is incremental to address an identified grid need relative to the California Energy Commission ("CEC") system forecast. The CEC forecasts deployment of various DERs at a certain magnitude and pace as well as some assumed operational profile for how, in the example of a BTM hybrid or storage resource, the resource charges and discharges in response to retail rates, program incentives, etc. While the CEC only recently incorporated BTM storage in its forecasts and has indicated its year-by-year improvements to the forecast in the Demand Analysis Working Group ("DAWG") meetings, the Joint Parties still see inaccuracies or uncertainties where an incrementality assessment cannot be fairly assessed for BTM storage based on these forecasted deployment levels and operational profiles. It is critically important to

17 *See* R.14-10-003, *Proposed Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments*, Finding of Fact 96 (January 5, 2021).

understand the uncertainty and inaccuracy attributed to any forecast, but some of these are beginning to be understood for the CEC system forecast.[18]

For the market-informed pathway, planning and procurement incrementality is potentially more straightforward, leading the Joint Parties to favor this pathway. For a load-side resource, clear load forecasting and adjustment processes could be used to guard against double counting of BTM hybrids and storage to support the market-informed pathway. Similar to how there is a load forecast adjustment process done by the LSEs in conjunction with the CEC to account for load migration, a similar process should be clearly developed and identified for reducing LSE procurement obligations when LSEs procure market-informed RA-like BTM resources. This adjustment process should be timed to enable LSEs to reflect them in their year-ahead RA showing in October of every year, with potential future possibilities of having them reflected in month-ahead showings.

Second, operational and performance incrementality is distinct from planning and procurement incrementality in that the latter is an advanced *ex ante* determination on the eligibility of the resource for counting toward RA supply plans and other compliance mechanisms. By contrast, operational incrementality involves the operationalization of the supply and demand balance by LSEs to serve their customers' load and the CAISO to serve the entire system load just before or during the RA or RA-like "delivery" periods. As the Joint Parties understand it, the CAISO forecasts the load that needs to be served based on historical and recent data, without visibility into whether and how BTM resources may be shown as supply or load, leading to some challenges to forecasting supply needs to reflect both the typical and expected behavior of the BTM hybrid and storage resources. To address this issue, the Commission and the CAISO should seek to understand how these operational forecasts reflect what the resource "was going to do anyway" versus what the market "expected the resource to do." Again, the complexity of this issue is seemingly reduced under the market-informed pathway, whereby the expected use of the resource can be reflected in its load scheduling based on its contracted commitment to provide RA-like services to the LSE but outside of the CAISO market.

18 For discussion on some of the issues observed in the Demand Analysis Working Group, *see* Track 3A Proposal, p. 12.

VI. Common Issues - Market Integrated Pathway

A. Retail/Wholesale Estimation Methodology for BTM Storage

Sale for resale should only be an issue for BTM standalone storage resources, as storage units in a hybrid configuration would charge from the onsite solar, thus not creating a sale (at wholesale) for resale (at retail) issue. The overarching concern is that a BTM storage device may obtain charging energy at wholesale and provide retail services, which include onsite customer services. In D.18-01-003, the Commission chose to defer decision-making on measurement, metering, and settlement rules for a resource that may provide both wholesale and retail jurisdictional services.

The Commission's lack of movement on this topic has had the immediate result of causing the CAISO to hold off on permitting resources to participate in its NGR model—including DERP resources—on a non-continuous basis. The specific concern is delineating wholesale and retail charging energy to provide wholesale market and non-wholesale market services, respectively. Confusion and lack of progress on this use case have also been cited by the CAISO to further delay the ability for BTM storage to fully participate in the wholesale markets. The CAISO has resolved the issue for now by identifying all BTM storage charging at retail. That said, this does not address a BTM standalone storage system that still wishes to charge at wholesale for wholesale market participation. Regarding measurement, notably, the IOUs' station power rules for IFOM energy storage resources utilize estimation methodologies to estimate retail and wholesale loads, in lieu of direct metering. The Joint Parties recommend that the CPUC revisit rules for this use case, either as part of the utility station power tariffs for energy storage or a separate tariff.

B. Coordination at T&D Interface

FERC Order 2222 requires each RTO/ISO to include coordination protocols and processes for the operating day that allow utilities to override RTO/ISO dispatch of a DER aggregation in circumstances where such override is needed to maintain the reliable and safe operation of the distribution system. This follows the CPUC's supportive comments in FERC Docket No. RM18-9-000:

> [I]t may be worthwhile to establish a system and protocols by which the distribution utility and the ISO/RTO are permitted to communicate directly about the need to dispatch

a resource, if that resource is simultaneously contracted to provide both distribution level and wholesale level service. Currently, in California, any transfer of information must happen through the actual resource owner, either directly, or in giving permission.[19]

While it is reasonable for IOUs and the ISO to coordinate on resource dispatch for the purpose of determining and mitigating distribution system impacts, it should not be assumed that enabling BTM systems to export to the grid for RA purposes will automatically result in new safety or reliability challenges. Rule 21[20] requires all BTM grid-interactive, state-jurisdictional resources to pass through multiple screens to ensure safe and reliable operations, which identify needed distribution upgrades to realize the safe export of power. When a DER system requests interconnection with the ability to export past the customer meter, Rule 21 screens ensure those exports can take place without compromising safety and reliability. The systems are approved for export, sometimes with requirements for mitigations that must be performed before interconnection.

The coordinated dispatch of exporting DER aggregations is an additional consideration that can be addressed directly between distribution utilities and aggregators. This can be done without directly involving the CAISO. It can be achieved through existing or modified Rule 21 processes and agreements that provide for open communication channels and well-defined roles and responsibilities between aggregators and utilities.

Regarding outages, the wholesale distribution access tariff ("WDAT") delineates roles and responsibilities for communications between distribution providers and interconnection customers.[21] Distribution operators must notify aggregators at least five business days in advance of any planned outage stemming from routing maintenance or construction. Similarly, the distribution provider may suspend interconnection service to the customer under emergency conditions or forced outages.

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[19] CPUC FERC Comments, p. 11.

[20] Electric Rule 21 governs retail interconnections and is jurisdictional to the CPUC. *See* SG&E's Rule 21 tariff: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE21.pdf; SCE's Rule 21 tariff: https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/rules/ELECTRIC_RULES_21.pdf; PG&E's Rule 21 tariff: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

[21] *See, e.g.*, SCE WDAT, Attachment 9, SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA), Section 3.4 – Temporary Disconnection, *available at* https://library.sce.com/content/dam/sce-doclib/public/regulatory/open-access-information/wholesale-distribution-access-tariff/SCE_WDATCombinedFile.pdf.

These basic provisions can be adapted in Rule 21 to enable streamlined T&D coordination between distribution system operators ("DSOs") and aggregators for wholesale DER dispatches. If the DSO provides advanced notice of a planned outage, this should prohibit the aggregator from bidding its resource (or portions of its resource) into the CAISO market. Otherwise, under normal expected operations, aggregators that receive market awards from the CAISO would inform the DSO of the scheduled dispatch, which would open a two-way messaging channel between the distribution operator and aggregator. The distribution operator would be responsible for informing the aggregator of localized, unplanned grid outages or emergencies that arise between the time of award and the delivery hour. The aggregator, in turn, would be responsible to submit a "transmission-induced" outage card to the CAISO, which is already provided for in the CAISO Business Practice Manual for Outage Management when a distribution equipment outage curtails a distribution-connected generator,[22] for either a planned or unplanned grid outage.

This communication flow obviates the need for distribution utilities to "override" a DER aggregation dispatch, which would require utilities to continuously track and intervene in CAISO market runs and third-party market awards—a significant departure from current utility roles in CAISO. The Joint Parties recommend that the Commission include a review of these roles, responsibilities, and processes in the scope of future Rule 21 work to enable state-jurisdictional interconnection agreements for wholesale DER aggregations.

C. Revisiting Wholesale Market Interconnection

Currently, the interconnection process that governs distribution-interconnected resources that export to the wholesale market is the WDAT. WDAT has proven lengthy, costly, and burdensome for DERs, and importantly, there is no state-level entity that has any jurisdiction over WDAT: it is a utility tariff that is regulated by FERC. However, the CAISO tariff leaves the determination of the appropriate interconnection process for PDR, reliability demand response resource ("RDRR"), and DERP to the local regulatory authority, which is the CPUC. FERC determined in Order 2222 that:

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22 *See Business Practice Manual for Outage* Management, Section 3.4: Nature of Work Attributes for Generation Outages, CAISO, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Outage%20Management/Outage%20Management%20BPM_Version%2026_Redline.pdf.

> [W]e decline to exercise our jurisdiction over the interconnections of distributed energy resources to distribution facilities for the purpose of participating in RTO/ISO markets exclusively as part of a distributed energy resource aggregation. Thus, we will not require standard interconnection procedures and agreements or wholesale distribution tariffs for such interconnections.[23]

Order 2222 later states:

> We do not believe that requiring standard interconnection procedures and agreement terms for these interconnections is necessary to advance the objectives of Order Nos. 2003, 2006 and 845, which established standard interconnection procedures and agreements in order to prevent undue discrimination, preserve reliability, increase energy supply, lower wholesale prices for customers by increasing the number and types of new generation that would compete in the wholesale electricity market, reduce interconnection time and costs, and facilitate development of non-polluting alternative energy sources. **Rather, we agree with commenters that state and local authorities, which have traditionally regulated distributed energy resource interconnections, have the requisite experience, interest, and capacity to oversee these distribution-level interconnections**.[24]

This conclusion of FERC Order 2222 clearly points to the use of Rule 21 rather than WDAT. As discussed above, the review process under Rule 21 for exporting resources includes a series of screens designed to avoid exceeding any safety or reliability constraint on the distribution system. In response to FERC Order 2222, the Joint Parties recommend that the CPUC scope a new issue into the Rule 21 proceeding to amend the tariff to provide for coordination with the CAISO to consider network reliability related to RA participation by DERs. The Joint Parties further recommend that the CPUC convene a series of technical workshops with the CAISO and distribution utilities to determine any modifications needed to Rule 21 to enable wholesale market participation. Distribution utilities must consider the combined impacts of fleets of DERs operating in concert. Also, the Commission should ensure that the CAISO has the information it needs to maximize the efficiency of its deliverability considerations so that it can allow DERs to enter the market without unnecessary delays.

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23 FERC Order No. 2222, P 90.

24 *Id.*, P 96 (emphasis added).

VII. Conclusion

The Joint Parties appreciate the Commission's consideration of this Proposal and look forward to working with Staff and other parties on the issues addressed herein.

Respectfully submitted January 28, 2021,

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