**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

**Modernizing Electricity Market Design ) Docket No. AD21-10-000**

**COMMENTS OF THE AMERICAN CLEAN POWER ASSOCIATION**

The American Clean Power Association[1] ("ACP") appreciates the opportunity to comment on energy and ancillary service market design and offer answers to the Commission's questions in its notice issued December 6, 2021 in Docket AD21-10.[2] The Commission's inquiry is timely and vital. Many aspects of ancillary services and energy markets were defined by the Commission in 1996's Order No. 888.[3] Although refined since then, the core ancillary services generally remain in place – and rest upon the same record that the Commission considered more than a quarter-century ago.[4] The Commission should critically evaluate these services, and direct public utilities to make changes where appropriate. As the nation's resource mix continues to rapidly shift towards clean energy, it is essential that energy and ancillary services markets procure the

---

[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACP.
[2] Notice Inviting Post-Technical Conference Comments, Docket No. AD21-10 (Dec. 6, 2021), https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20211206-3028.
[3] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* ("Order No. 888"), 61 Fed. Reg. 21,540 (1996), FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 P 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Statutes and Regulations P 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC P 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC P 61,046 (1998).
[4] Order No. 888 at 21580. (Listing six ancillary services: "(1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve—Spinning Reserve Service; and (6) Operating Reserve—Supplemental Reserve Service.").

services that will ensure reliable service at just and reasonable rates. To that end, ACP offers these comments to inform future Commission action.

## I. SUMMARY AND PRINCIPLES

Today's electricity and ancillary services markets presume – and in many cases, are structured specifically to resolve – the *inflexibility* of large, central generators, which made up the large majority of energy supply in the 1990s. Wind and solar power generation are increasing rapidly as a share of the supply mix across the U.S., and grid operators have improved on operations strategies to integrate higher shares of renewable power while maintaining system reliability. Additionally, inverter-based clean energy resources – particularly energy storage – are providing new technological capabilities to grid operators for flexible system operations. Indeed, the power system is no longer dominated by inflexible large generators. Technological capabilities and practices for flexible system operation should now prompt the Commission and transmission providers to revisit market designs built on the foundations of a different era in our power system. It is clear from the record in this docket that existing Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") market software and rules were designed for a resource mix that is quickly becoming obsolete.[5]

As a first order of business, the Commission should critically examine current energy and ancillary services market designs, rules, and operations to determine where they provide an implicit subsidy to, or are otherwise unduly preferential toward, *inflexible* resources. ACP suggests that the Commission can achieve this goal through one or more proceedings that systematically identify the components of market designs, rules, and operations in each of the RTOs/ISOs that unduly accommodate or subsidize inflexibility. If the Commission determines that rules or processes amount to an unduly preferential approach to inflexible resources, then the Commission can begin to address those issues

[5] Although the record has not been comparably developed, the Commission should also consider whether similar issues affect non-RTO/ISO regions.

via Section 206 proceedings, Show Cause orders, a rulemaking of appropriate scope, a policy statement, or some combination of these. Some examples of inflexible practices in energy and ancillary services markets include:

- Economic minimum ("Ecomin" or "Pmin") – This practice allows scheduling parameters to account for the minimum quantity of electric energy that a generator can provide in response to economic dispatch. However, this can result in "lumpy" dispatch, as the ecomin is treated as a block that can displace otherwise-marginal, lower-cost resources.
- Uplift payments – These payments are assigned out-of-market as "make-whole" compensation for resources that were instructed to run (or not run) based on grid operator direction. However, more flexible energy and ancillary services products, offered on a more granular basis, may obviate the need for many uplift payments.
- Scheduling intervals – Although FERC's Order No. 764[6] required transmission providers to offer 15-minute scheduling – which provided some flexibility at the election of transmission customers - the Commission should consider whether prevalent scheduling practices implicitly or explicitly favor certain resource types.

ACP submits as an overarching goal that grid operators should specify needs and delegate performance responsibilities to market participants wherever possible, minimizing the amount of resource performance that is accommodated by administrative rule. For determining whether a market design and operations choice is unduly preferential, the Commission should ask: *is that design or operations choice capable of reasonably being met with current technologies and operations capabilities, or not*? It is critical that the Commission, in seeking to improve energy and ancillary services markets design, begin first by removing the baked-in assumptions of inflexibility that, left

[6] *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012).

undisturbed, will inherently constrain the value that new or modified market products can produce.

Corollary to this effort, the Commission should also begin to reform market structures to ensure that RTO/ISOs procure resources based upon overall customer needs, rather than on outdated assumptions regarding the generation mix. The Commission should therefore initiate a rulemaking or Policy Statement updating policies for ancillary services procurement. A rulemaking or Policy Statement could establish guidance on how RTO/ISOs should develop more granular products, when to create new products, and when to modify existing products. It is often the case that RTO/ISOs are hamstrung by stakeholder disagreement and committee process delays. Parties in these committees will argue basic ideological questions, or try to protect their individual interests, and fail to agree on specific rule or process improvements. The Commission can alleviate this constraint by directing parties to follow a just and reasonable framework for market design, so that the stakeholder process can focus on specific rule improvements consistent with the Commission's framework.

Additionally, the Commission should consider interim actions, such as Section 206 proceedings or Show Cause orders, against transmission providers with discriminatory rules or practices that restrict participation in certain markets or services based upon resource class rather than resource capabilities, either *de facto* or facially.[7]

In support of these actions, ACP offers the following principles:

---

[7] *See, e.g.*, MISO BPM -002-r22 at 151-52 ("[Dispatchable intermittent resources] *are not eligible* to provide Operating Reserves to the Day-Ahead or Real-Time Energy and Operating Reserves Markets. For this reason, DIRs do not submit Dispatch Statuses for Regulating, Spinning, On-Line Supplemental, or Off-line Supplemental Reserves."), *available at* https://www.misoenergy.org/legal/business-practice-manuals/. This constitutes discrimination solely on the basis of resource type, without reference to the operational attributes that these resources can provide.

1. **Flexibility and Granularity are Vital to Ensure that Markets are Truly Meeting System Needs.**

ACP agrees with FERC staff that "[a]s the need for operational flexibility in RTOs/ISOs continues to increase, the role of energy and ancillary services markets in providing price signals for the entry and retention of resources with flexible capabilities will likewise increase."[8] For this reason, market products should also become more granular and finely tuned to specific reliability needs, with a separate product when the specific need is different. For example, ramping down is a different need than ramping up, and should therefore be procured separately. Providing energy at a given 5-minute interval is different from energy for the full hour, and should be procured separately.[9] Granular product definition and pricing improves efficiency and reliability by targeting payments to the specific need, at the specific time and place it is needed.

If new or more specific services can better meet reliability needs than existing services, and resources are capable of providing those new services,[10] new reliability service products should be created. Renewable and storage resources can often respond more quickly and accurately to system needs than conventional resources, allowing more reliable and efficient operations. When a different set of sources, with a different system supply curve, can serve a system need, that is a strong indication that a separate product should be created.

Product definitions should be precise. Energy and Ancillary Services ("E&AS") markets procure more granular and flexible services over various time scales than capacity markets, which focus on long-term availability months or years ahead. Consumers should not pay "money for nothing." Sometimes, poorly defined products can

---

[8] Staff White Paper on Energy and Ancillary Services (2021) at p. 26 https://www.ferc.gov/sites/default/files/2021-09/20210907-4002_Energy%20and%20Ancillary%20Services%20Markets_2021_0.pdf.

[9] Lawrence Berkeley National Laboratory, *Variable Renewable Energy Participation in U.S. Ancillary Services Markets* at 23 (2021) *available at* https://eta-publications.lbl.gov/sites/default/files/vre_as_full_report_release.pdf (*hereinafter* "LBNL Report").

[10] LBNL Report at 23.

lead to payments to resources that may be *capable* of providing services – but may not perform when needed. This has been the case in some capacity markets over the last two decades. Better performance-based product definitions and requirements on resources eligible to provide the product will help ensure consumers gain value from the resources that are selected and compensated for a given service they successfully provide.

RTO/ISOs can also focus on improving their existing energy, regulation, and reserves products to incorporate all sources of uncertainty. "Contingency" reserves need not only include the loss of individual generation units, but can evolve to incorporate other causes of uncertainty and variability such as renewable energy output. Additional products for flexibility may be needed in a given RTO/ISO system if its core products do not satisfy all reliability needs, given the resource mix and market structure of that region. Additionally, procurement in advance of a day-ahead market ("multi-day ahead markets") may be useful for certain RTO/ISOs to ensure sufficient resources are on-line and financially committed to perform; because RTOs/ISOs typically have day-ahead markets already, this reform could be effective and rapidly implementable.

When specific reliability needs are very similar, products can be merged to increase competitiveness and the pool of resources able to provide the service. For example, if ramping up in a given number of minutes is needed to cover either a coal plant forced outage or an un-forecasted reduction of system-wide wind energy output, that service should be supplied via the same product. This type of operationally comparable need can be provided by the same pool of resources, and a single product will enlarge the pool competing to provide it.

2. **The Commission Should Ensure that Energy and Ancillary Services are Procured on a Resource-Neutral Basis**

Compensation rules should pay all resources for the services they actually provide, and renewable resources and storage should receive the same treatment as conventional resources. Changes to products or the addition of products should be based primarily on the reliability need, such as the possibility of supply-demand shortfall in different situations, and not designed to accommodate the capability of the resources that have historically provided the service. Product definition should allow all resources that are capable of providing the service to do so,[11] and market rules should not prevent resources from providing services they are capable of providing. For example, some regions have duration requirements that prevent renewable and storage resources from providing ancillary services, even though they are capable of providing those services for shorter periods of time.[12] The procurement of ancillary services as close to real-time as possible with a time duration requirement appropriate for the desired service would (1) allow renewable and storage resources to better optimize their capability between energy and ancillary services and (2) allow curtailed renewable resources to offer their headroom for upward ancillary services. This will be increasingly important as the resource mix continues to shift towards inverter-based resources.

All resources, including renewable sources should be fully compensated for the services they provide. Renewables should not be penalized for variability, but instead should be fully compensated for energy and ancillary services at the time and place they provide it. If the system experiences net load variability, it needs to procure balancing from whichever resources can provide it. Sometimes that will be renewables, but many times it will not be; if a renewable resource cannot provide a particular service in a particular interval, it should simply not receive compensation. Energy is fungible, but the other ancillary products are differentiated, and should include those with the physical capability to provide it. Improved forecasting and more granular time periods will help to assure that all services are fully supplied (and that participating resources are

[11] *Cf.* Order No. 841, 162 FERC ¶ 61,127 at P 20 (2018) (*hereinafter* Order 841).
[12] *See, e.g. See, e.g.*, MISO BPM -002-r22 at 151-52 ("[Dispatchable intermittent resources] *are not eligible* to provide Operating Reserves to the Day-Ahead or Real-Time Energy and Operating Reserves Markets. For this reason, DIRs do not submit Dispatch Statuses for Regulating, Spinning, On-Line Supplemental, or Off-line Supplemental Reserves."), *available at* https://www.misoenergy.org/legal/business-practice-manuals/; *see also* LBNL Report at 24.

appropriately compensated) even if renewables in a particular geographic area have reduced production at a given moment.

For example, exceptional dispatch of energy storage – which can require a storage resource to maintain a state of charge for a period of time – should be fully compensated according to estimated missed market revenues due to the exceptional dispatch instruction.[13] Additionally, market power mitigation rules should not prevent storage resources from providing services if their opportunity cost is ambiguous. In many cases the opportunity cost is ambiguous for a storage resource using state of charge to provide a service now, at the expense of not being able to provide a service in the future.

E&AS markets should better incorporate demand side resources, not just in emergency situations but in normal market operation, as an additional source of flexibility.

**3. Software, Systems, and Related Market Rules Must Keep Pace**

For efficiency and reliability, the Commission should encourage rapid evolution of grid operator software and systems to better accommodate the future resource mix and produce just and reasonable rates for consumers. The testimony from each of the six FERC-jurisdictional ISO/RTOs demonstrates their general awareness and recognition of significant changes taking place and the need for their systems to evolve. ACP submits that the record to date shows that the RTOs/ISOs are each trying to evolve. In many cases their different approaches and speeds reflect the differences in their resource mix or the market structure, systems, or software packages for each grid operator. Computing power is a scarce commodity, and choices will need to be made about how it should be spent. Current systems that use complex algorithms to optimize the historical resource

[13] *See* Order No. 841 at P 52. In its energy storage enhancements initiative, CAISO is considering a compensation methodology for energy storage resources who receive an exceptional dispatch instruction to hold their state of charge, that compares expected revenues from market participation with and without the exceptional dispatch. https://stakeholdercenter.caiso.com/StakeholderInitiatives/Energy-storage-enhancements

mix with their non-convex cost curves may be wasting computing power that could be better applied to the future resource mix.

Transmission providers should also endeavor to improve forecasting of generation and load over different operational time scales, from minutes to days. Reducing uncertainty will improve commitment and dispatch.[14] E&AS markets should also become "faster," with more frequent re-dispatch and shorter time scale products than is generally in use today. Resources should also be able to switch among providing energy and different ancillary services in real-time (or as nearly as possible) as system needs change.

4. **Price formation should drive efficient short- and long-run behavior**

Product pricing should be based on marginal operating or opportunity cost when supply is sufficient, and based on value to the customer when supply is short. Unless and until there is sufficient actual demand-side bidding, administrative estimates of Value of Lost Load should be used at these times. VOLL-based pricing will provide short- and long-run price signals needed to encourage efficient performance and investment. The design of all market products can and should influence entry and exit decisions, and thus should reflect Value of Lost Load at times of scarcity. Ancillary services costs are only 2-3 percent of total power market costs even in Texas[15] and California[16] (regions with high renewable penetration, and a need for corresponding flexibility). Most analysts and models expect that number to rise as system variability increases. Even if ancillary services costs increased, they would only represent a minimal component of total consumer bills – and, as detailed below, customers would receive better performance with appropriate updates.

[14] LBNL Report at 22.
[15] Ancillary services cost were 3% of total energy costs in 2020. https://www.potomaceconomics.com/wp-content/uploads/2021/06/2020-ERCOT-State-of-the-Market-Report.pdf
[16] Ancillary services costs were 2.23 percent of total energy costs in 2019. http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

The *full* value of energy and ancillary service products should be reflected in E&AS product prices, which should be fully differentiated from capacity products (the latter should focus less on flexibility and more on the need for resources to meet peak net load). Prices should generally be higher for higher performance products such as those that require faster response times. Higher prices will naturally result if the products and requirements for supply sources are defined correctly (fewer resources will likely be able to provide the faster ramping product, resulting in a higher and steeper supply curve). While some amount of out-of-market operator actions will likely be necessary, they should be minimized - and RTO/ISOs should endeavor to incorporate all such operator actions into market products with appropriate transparent pricing to achieve efficient short- and long-run behavior. RTO/ISOs should similarly endeavor to minimize total uplift costs. Uplift costs should be reported to the public and the Commission, along with the reasons for the costs and options to incorporate the actions into products and prices.

### 5. Ancillary services costs should be allocated on a non-discriminatory basis

Load currently pays for variability and uncertainty costs imposed by conventional resources, whether due to forced outages or their inflexibility – through practices such as those described above. As markets transition to more flexible and granular products, renewable sources should not be singled out for direct assignment of costs. Rather, market design should reward resources capable of flexibly and accurately meeting system needs in a particular interval, without expressly or implicitly subsidizing inflexible resources. For example, gas scheduling constraints and thermal generator inflexibility cost consumers money. Power markets should provide incentives to improve fuel scheduling flexibility and make generators more flexible, or at least disincentives for inflexibility.

## II. COMMENTS ON POST-TECHNICAL CONFERENCE QUESTIONS

### Panel 1: Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets

1. ***RTOs/ISOs and other industry experts generally agree that power systems will require greater flexibility from system resources in the future. What operational capabilities or services will be most valuable to RTO/ISO operators in the future as the resource mix and net load profile changes and why? Is there a desirable reaction time, sustained performance duration, etc. expected from a resource?***

ACP agrees that system needs are changing, and that flexibility will become more needed and valuable. The exact need (response time, quantities, etc.) varies by region, and will change over time on each system. For example, the retirement of a large conventional unit may reduce the need for reserves to cover the contingency of an outage. Weather patterns that may affect a given region with a particular resource mix may cause situations where a certain amount of ramping resources will be needed in a certain time frame. Market product design details will depend on the region's resource mix, level of uncertainty, and variability in load and generation. Most short-term (sub-hourly) variability and uncertainty in wind and solar output is canceled out with a diverse portfolio of wind and solar generation across a reasonably large geographic footprint.[17]

2. **To what extent will the "traditional ancillary services" defined in Order No. 888 and existing energy market designs continue to ensure reliability as the resource mix changes in RTO/ISO markets in the future?**

    a. *Will traditional ancillary services provide the appropriate types and adequate quantities of operational flexibility RTOs/ISOs need to manage both expected (e.g., reasonably predictable) and unexpected (e.g., inherently uncertain and captured in forecast errors) variability in net load?*

---

[17] LBNL Report at 23.

The general principles of the Order No. 1000 ancillary services in the Commission's *pro forma* OATT remain sound, but many design details will need to evolve. Some terms such as "spinning" and "non-spinning" are antiquated, and refer to thermal generation. These should be replaced with technology-neutral terms, based upon response times and dispatchability. The Commission should aim for general consistency of product types (such as regulation, reserves by time frame, etc.) and should institute a *pro forma* set of standards on the key aspects. However, the Commission should allow for specific MWs, and MW/minute, duration to vary by region and over time, with a showing that such regional requirements are equivalent or superior to the *pro forma* requirements. If product definition specifics need to differ by region and over time based on engineering need and the resource mix, this would provide appropriate flexibility.

b. *Will existing RTO/ISO energy and ancillary services market designs that generally compensate certain traditional ancillary services resources based on the opportunity cost of foregone energy sales – for example, spinning and non-spinning reserves - give resources a sufficient economic incentive to offer their flexible capabilities to the RTO/ISO?*

Opportunity cost-based bidding and price-setting with co-optimization between products leads to efficient use of resources and assignment of resources to their highest and best use. As noted above, market power mitigation rules should not prevent storage resources from providing services if their opportunity cost is ambiguous. In many cases, the opportunity cost is ambiguous for a storage resource or a hybrid resource, which might use a state of charge to provide a service now at the expense of not being able to provide a service in the future.

***3. How should RTOs/ISOs define the system's need for operational flexibility, now and in the future?***

a. *To what extent is operational flexibility needed on a bi-directional basis (i.e., both up and down) versus a unidirectional basis (i.e., only up or down)?*

Both up-ramp and down-ramp are needed, but in different amounts at different times, and they can be provided by different units with different cost (including opportunity cost) profiles. Therefore, they should be different products.[18] ACP agrees with PJM's Adam Keech, who stated "It's not clear that that bidirectional definition is fundamental to the service, and so splitting it up would increase competition, it could allow different entrants into the market, and that could ultimately be to the benefit of consumer costs and reliability."[19] CAISO, ERCOT, and SPP already procure separate upward and downward regulation reserves.[20] However, all of these services should be open to all resources, which is not the case today; for example, SPP allows Dispatchable Variable Energy Resources to participate in downward regulation, but not in upward regulation.

The need in MW for particular services over different time scales could be adjusted over time based on the particular system.

c. *How do these needs compare to the services provided by traditional ancillary service products?*

The products are similar, but the specifics differ now from what was established 25 years ago in Order No. 888, and will continue to evolve in the future. For example, basing reserve needs upon single contingency events (such as the loss of a large thermal generator or transmission line) should be replaced or accompanied by probabilistic analysis, evaluating the risks from cumulative factors such as irradiance, wind speed, temperature, and load forecasts. The quantity, speed, and specific requirements will vary over time and across region, and coincident or complementary resource profiles should result in appropriate adjustments to reserve needs.

---

[18] LBNL Report at 28.
[19] September 2021 Technical Conference Transcript at p.56-57.
[20] *See* LBNL Report at 9.

***4. Could variable energy resources or new resource types (e.g., storage, hybrid, and co-located resources) be operated or dispatched differently from the status quo to provide greater operational flexibility to the RTO/ISO, if so, how? Given the evolving resource mix, are the current eligibility requirements for each resource type to provide ancillary services appropriate?***

Yes, wind, solar, storage, and hybrid plants can provide substantial, fast-responding flexibility that is not yet being fully utilized.[21] Some of the participation models and market rules are excessively restrictive.[22] The September 20, 2021 comments of the Hybrid Resource Coalition in Docket No. AD20-9 identify many of the shortcomings of current participation models, and improvements that should be made to appropriately account for their attributes.[23]

**Panel 2: Revising Existing Operating Reserve Demand Curves (ORDCs) to Address Operational Flexibility Needs in RTOs/ISOs**

1. ***Contingency reserves are provided by existing 10- and 30-minute reserve products and are designed to ensure the system can recover from a contingency (e.g., a generator or transmission outage). How will the procurement of additional contingency reserves help RTO/ISO operators manage routine operational flexibility needs (e.g. needs driven by net load variability and uncertainty)?***

---

[21] *See e.g.* California Independent System Operator and National Renewable Energy Lab, *Using Renewables to Operate a Low Carbon Grid* at 56 (2018)("Advancement in smart inverter technology combined with advanced plant controls allow solar PV resources to provide regulation, voltage support and frequency response during various mode of operations."), *available at* http://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf (*hereinafter* NREL Study); California Independent System Operator and National Renewable Energy Lab*, Avangrid Renewables Tule Wind Farm: Demonstration of Capability to Provide Essential Grid Services* at 5 (2020)("The results demonstrate that wind resources have the capabilities to help accelerate the shift toward a future electric grid with high levels of renewable generation. These results—much like those from a similar test in 2018 on an inverter-controlled solar power plant—promise next-generation advances for increased amounts of renewable generation, including pairing it with storage to create more effective dispatchable resources."), http://www.caiso.com/Documents/WindPowerPlantTestResults.pdf.

[22] *See* LBNL Report at 22-25.

[23] *See* Comments of the Hybrid Resource Coalition, Docket No. AD20-9 (Sept. 20, 2021), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=066908BF-5067-CE0E-B547-7C0868B00000.

The general concept of a defined quantity of reserves in a given speed of ramping will continue to be needed. The specific quantity of demand should be dynamic, to account for greater needs in certain situations. The reserve product would be more efficient and competitive if it were defined not just based on a certain type of contingency, but rather any source of unforecasted imbalance including the impact of weather on electricity supply and demand. ACP concurs with Debra Lew of the Energy Systems Integration Group, who stated "Reserves should be dynamic. They should be sized based on current forecasted conditions. So if it's raining all day in a region, you probably don't need solar reserves at that time."[24]

***2. What are the benefits of procuring contingency reserves beyond the minimum reserve requirement through a given ancillary service product?***

The electric grid is shifting from a need for reserve products that respond to a specific defined event (contingency), to a world where a variety of factors can occur in combination with some probability of creating an imbalance of some size. This is more of a probability distribution than a specific amount, and will necessarily vary at different times and in different situations.[25] It will be more efficient for consumers to have a single product in instances where the reliability need is largely the same (e.g., recovering from a generator forced outage or a loss of wind or solar output require similar resources on an operational basis). However, this product will be far more reliable if higher quantities are procured in certain situations such as weather fronts moving through a region where generation output is harder to predict. This will also assist in transparent pricing, so that resources can respond to system needs in closer to real time.

*a. If employing such a method, how should RTOs/ISOs determine the market's demand for contingency reserves (both the quantity and*

[24] September 2021 Technical Conference Transcript at p. 30.
[25] *See* LBNL Report at 23.

*willingness to pay) beyond the minimum reserve requirement of a given contingency reserve product?*

The amount should be determined through probabilistic estimation using historical data. Given variability of load and different types of generation, one can use standard statistical techniques to estimate the distribution of possible outcomes.

*b. What principles should RTOs/ISOs follow if they consider revising the shape of the ORDC for a given contingency reserve product (e.g., introducing additional steps or graduation to the ORDC curve)? For example, should the willingness to pay for such additional reserves be based on the Value of Lost Load times the loss of load probability with a given quantity of the reserve product associated with the ORDC, the cost of actions operators would take to procure additional reserves, or some other valuation method? How should customer willingness to pay be incorporated?*

Yes, the price of a product should be based on consumer valuation when demand exceeds supply, as in typical markets across the economy and as explained in standard economic theory. Over time, that consumer valuation should be expressed by actual consumers based on their willingness to consume or reduce consumption at different price levels. Unless and until there is true demand side bidding, administrative estimates of Value of Lost Load should be used.

***3. Reserve shortage prices are administratively determined penalty factors invoked when the system falls below the minimum requirement of one or more reserve products. To what extent can higher reserve shortage prices inform investment decisions and reflect the value of flexible resource capabilities?***

*a. What principles should RTOs/ISOs follow if they consider revising the shortage price associated with the ORDC of a given contingency reserve?*

As stated above, administrative estimates of Value of Lost Load (VOLL) should be used. Shadow pricing may be appropriate to ensure indifference between energy and reserve provision from any individual resource capable of supplying either.

b. *How should the shortage prices of individual contingency reserve products be determined? For example, should the shortage prices reflect the marginal reliability value of each individual reserve product? How should customer willingness to pay be incorporated?*

Generally, the VOLL is the same across products, but loss of load probability is different between products and at different quantities of each product. There will tend to be less supply available for higher quality and harder-to-provide products such as very fast-ramping short-notice products. That will tend to result in higher prices for higher quality products.

c. *How should shortage pricing be implemented when the system is short both 10- and 30-minute reserves? Does establishing shortage prices based on the marginal reliability value of each contingency reserve product that is in shortage ensure that adding the shortage prices reflects the combined reliability impact of being short of those reserve products?*

Demand for each reserve product should be based on VOLL, or marginal reliability value.

d. *Do differences in shortage prices across regions present operational challenges today? Is there an expectation that such differences could present operational challenges in the future as the resource mix and load profiles change? Is there a need to better align shortage pricing across RTOs/ISOs, and if so, what principles should be considered in doing so?*

Yes, it can be inefficient if neighboring regions have different VOLL determinations. If the actual consumer valuation differs, a difference can be efficient. But given the likely use of administrative VOLL, the Commission should take care to avoid inefficient and unjustified differences between regions.

4. ***To what extent do RTOs/ISOs use contingency reserves to manage non-contingency related operational uncertainties (e.g., expected and unexpected net load variability)? If such reserves are used for this purpose, should this alter an RTO/ISO's approach to establishing the maximum height and shape of***

***the ORDC? Under such approaches, how do prices in the ORDC appropriately reflect the marginal reliability value contingency reserves provide?***

Reliability needs that are essentially the same (i.e. X MW needed in Y minutes) should be grouped together to increase competition across all of the types of resources that may be able to provide that service. A certain contingency is only one reason the system may need that service, but often not the only cause for that system need. As noted above, ORDCs should reflect the Value of Lost Load, both in terms of placement and the shape (slope) of the curve.

5. ***Is there a particular point at which procuring reserves beyond the minimum reserve requirement can reduce or conflict with the objectives of shortage prices? What is an appropriate balance between raising shortage prices and procuring reserves beyond the minimum reserve requirement given that procuring additional reserves can reduce the probability of the RTO/ISO experiencing a shortage?***

An appropriately placed and shaped ORDC will only pay for resources that are providing value. There is likely some value beyond the minimum required amount, but at a certain point that value approaches zero and the demand curve should reflect that.

**Panel 3: Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs**

1. ***Ramp products, as distinguished from traditional ancillary service products, are relatively new ancillary services that are in place in CAISO and MISO, and approved for implementation in SPP. Ramp products are generally not designed to address contingencies[26] but are instead a mechanism to position the system efficiently to meet forecasted ramping needs in future intervals at least cost on an expected basis.***

---

[26] For example, ramping products are not designed to be substitutable with the reserve products used for managing contingencies. *See e.g.* CAISO, *Flexible Ramping Products Straw Proposal* at 7, 10 (Nov. 1, 2011) http://www.caiso.com/Documents/FlexibleRampingProductStrawProposal.pdf; Sw. Power Pool, Inc., Filing, Docket No. ER20-1617-000, at 13 (filed Apr. 21, 2020).

There is no meaningful distinction between "contingency" and the "ramp" needed to address other sources of uncertainty. Products should evolve to address system needs, not focus only on individual causes of that system need.[27] In a sense, all products including the traditional ancillary services are "ramping" products. Flexible resources capable of providing what is defined in some regions today as "ramping" products can typically also provide reserves in the event of a contingency.[28] As noted above, a probabilistic approach to reserves could identify needs, and all resources capable of supplying the aggregate system needs in the appropriate time interval should be appropriately compensated.

a. *RTO/ISO ramp products procure ramp on a short-term basis (e.g., for intervals of 10 or 15 minutes), but longer-term ramp products are being considered. For example, SPP is considering a longer-term ramp product*[29] *and the California Department of Market Monitoring has advised CAISO to consider a longer-term ramp product.*[30] *What drives the need for, and what are the benefits of, a longer-term ramp product compared to the existing shorter-term ramp products or traditional reserve products?*

If the probabilistic analysis identifies the potential for shortfalls in different time frames, the MW and MW/minute needs should be defined and procured with a VOLL-based ORDC. If there is a need in the short term and long term, they should both be procured, just with different MW/minute requirements.

These ramp products should also enable resources to deliver their full capabilities, which is not always the case. For example, SPP effectively limits Dispatchable Variable Energy Resources to a maximum ramp rate of 8 megawatts per minute (below 200MW), or one-

[27] *Comments of the Hybrid Resource Coalition*, Docket No. AD20-9 at 17 (Sep. 2021).
[28] *See* NREL Study at 40.
[29] *See* Sw. Power Pool, Inc., "RR449 – Uncertainty Product" (July 27, 2021), https://www.spp.org/Documents/64125/rr449.zip. *See also* Sw. Power Pool, Inc., *Uncertainty Product Prototype Design Whitepaper* (Mar. 13, 2020).
[30] CAISO Department of Market Monitoring, Comments on Issue Paper on Extending the Day-Ahead Market to EIM Entities, at 8 (Nov. 22, 2019).

fifth of 20% of the emergency maximum capacity operating limit per minute (for resources above 200MW). However, renewable resources can ramp *far* more quickly, and market rules can accommodate this; in ERCOT, resources can ramp at 20% of nameplate per minute (going from 0% to 100% in five minutes), and in CAISO there are no specific provisions for ramp rates for Variable Energy Resources. Inflexible rules fail to optimize the use of inverter-based resources, and grid operators are therefore failing to receive the full benefits of these services.[31]

2. ***Will establishing reserve and ramp prices based on foregone energy revenues provide such signals in a system with a high penetration of variable energy resources, many of which have low or zero marginal costs?***

Yes. Opportunity cost-based pricing and sorting of resources puts resources to work in their highest and best use.[32] It may be the case that the efficient opportunity-cost based bid and price is zero over many intervals for many products. But at other times when there is more demand than supply, the price should be set more by the shape of the demand side than the supply curve, with higher quality products getting a higher price.

a. *If not, what other options exist to ensure sufficient compensation for resources providing reserve and ramp capability?*
b. *Historically, the prices for the ramp products in CAISO and MISO have often been zero. Are ramp prices expected to increase over time as system needs evolve? If so, what specific conditions might cause ramp prices to increase? Will any expected ramp price increases be sufficient to incent and appropriately compensate the ramp capability RTOs/ISOs and others expect will be needed due to the changing resource mix?*

If the price is zero when demand does not exceed supply, that is the efficient price for that point in time. In the future, there will likely be more times when supply may be constrained, and the price should be allowed to reflect the value at those times. And long-

---

[31] *See* Testimony of Betsy Beck, Enel North America, October 2021 Technical Conference Transcript at 84
[32] *See* LBNL Report at 7-10.

term contracting would likely have positive pricing to reflect the changes of supply shortfalls.

3. ***CAISO is considering a Day-Ahead Energy Market Enhancement proposal that seeks to ensure that the day-ahead market clears sufficient resources to address expected net load variability and uncertainty that arises between day-ahead and real-time. What are the expected advantages and disadvantages of revising the day-ahead market construct in this way to procure additional operational flexibility?***

System operators should ensure there are sufficient resources available to meet expected net load, given the variability and uncertainty of supply and demand resources. These resources should be procured on a competitive basis. Some regions will need to do that 24 hours ahead of time, or at other points in time, either closer to or further from real time.[33] As forecasting capabilities continue to improve, this type of advance procurement could be effective.

4. ***The Electric Reliability Council of Texas, Inc. (ERCOT) has proposed to procure fast-responding, limited duration products to address primary frequency control issues associated with declining system inertia.[34] CAISO also intends to initiate a stakeholder process to discuss, among other options, compensating internal resources for the provision of primary frequency response.[35] What are the merits of such reforms and should they be considered in other regions?***

The smaller size of the ERCOT interconnection creates a greater need for frequency support. The Western Interconnect is much bigger, and the Eastern Interconnect is still bigger, and the inverter-based resource penetration is much lower in these larger

[33] LBNL Report at 22-23.
[34] *See* Pengwei Du et al., *New Ancillary Service Market for ERCOT*, IEEE Access Volume 8, https://ieeexplore.ieee.org/abstract/document/9208672.
[35] *See* CAISO, *2021 Three-Year Policy Initiatives Roadmap and Annual Plan*, http://www.caiso.com/InitiativeDocuments/2021FinalPolicyInitiativesRoadmap.pdf.

interconnections. So with greater supply of inertia and frequency response, there will be much more time before the Eastern or Western interconnections find themselves needing to pay for frequency response as ERCOT does. Ultimately, markets for frequency response would likely be valuable. Some markets around the world have or are considering minimum inertia requirements, which can ensure sufficient inertia at all times. That is likely not as efficient as a market, but it may be a practical tool in certain situations.

Renewable and storage resources should be compensated for providing fast frequency response that reduces the need for inertia and primary frequency response.[36] If the transmission operator determines that a resource can safely exceed its interconnection injection limit to provide frequency response in the seconds and minutes following a disturbance, the resource should be allowed to do so.

5. ***What other new products not yet discussed at this conference, do you think could increase operational flexibility in RTOs/ISOs?***

    a. *Can capacity markets or other, potentially new, "intermediate" forward market constructs that clear between existing capacity market auctions and the day-ahead timeframe help ensure that RTO/ISO operators have sufficient operational flexibility in real time?*

Yes, forward firm energy markets can be a valuable addition. If they are defined based on actual performance at certain times and places, then they are likely more granular than the crudely defined generic "capacity" product. On the other hand, the Commission

[36]North American Electric Reliability Corp., *Fast Frequency Response Concepts and Bulk Power System Reliability Needs White Paper* at 7 (March 2020)("[Fast Frequency Response] can be provided by many different forms of controls that inject additional power prior to the frequency nadir being reached during a frequency excursion event. Synchronous machine inertial response, a portion of traditional turbine-governor response, wind turbine generator (WTG) controls to extract additional power from the rotational energy of the turbine, and other fast-responding controls from batteries and solar PV all can be classified as FFR since they provide replacement power to the BPS during the arresting phase."), https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

should scrutinize the need for forward procurement and ensure that there is a reliability basis for it. ACP agrees with ISO New England's Matt White who stated, "capacity is very hard to define because system needs are very dynamic day to day, and are best procured on that timeframe for these services. There's a fundamental problem with unequal pay for equal performance if different types of capacity resources, flexible and non-flexible, get paid different prices in the auction than the auction three years in advance, but face the same performance incentives in real time in the energy and in the other performance mechanisms. And obviously, creating unequal pay for equal performance is not only bad market design, it happens to be discriminatory."[37]

b. *For example, can a new shorter-term forward market to procure expected operational flexibility needs held closer to the delivery period (e.g., three months ahead as opposed to three years ahead) and with a more granular delivery period than the annual capacity market (e.g., monthly or seasonal delivery period, or a delivery period based on the hours of an RTO/ISO's morning or evening ramp as opposed to the annual delivery period of most RTO/ISO capacity markets) help ensure that RTO/ISO operators have sufficient operational flexibility in real time?*

Yes, monthly forward markets can allow, for example, gas generators to procure LNG supply in the Northeast, or generators to plan maintenance according to when they are needed. Beyond the reliability need, the Commission should consider whether this forward hedging function should be the job of Load-Serving Entities or the RTO/ISO. The assumption when RTO/ISOs were created was that they would focus on very short-term spot markets and serve an "air traffic controller" function, while LSEs would handle longer term hedging on behalf of the load they serve. States have generally not assigned LSE responsibilities in this way, so many responsibilities are being pushed to the RTO/ISO. FERC should clarify how far in advance the RTO/ISO should be responsible for, vis-à-vis LSEs.

---

[37] September 2021 Technical Conference Transcript at 252.

**Panel 4: Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets**

1. ***To date, most RTOs/ISOs have pursued new ramping products or ORDC reforms, but not both. What are the tradeoffs to consider when deciding between these two approaches and how do they interact? Should these two types of reforms be considered substitutes or complements? Does the opportunity-cost-based method of establishing reserve and ramping product prices send appropriate long-term signals to resources to invest in or maintain flexible capabilities?***

Products should be defined by the quantity and speed of response, and the demand for them should be set according to the value. So in that sense, both types of reforms are called for, and can be complementary.

2. ***Some entities have observed that offering additional resource capabilities into energy and ancillary services markets may not be in the financial interest of certain resources because doing so could lower energy prices by either avoiding scarcity conditions or obviating the need to commit more expensive units, and thus reduce their expected energy and ancillary services markets revenue. Are such incentive issues relevant in the context of reforming energy and ancillary services markets to address operational flexibility needs? If so, how should such issues be addressed?***

Withholding supply to raise prices is a market power issue that market monitors and the Commission should seek to identify and remedy. Products should be defined based on reliability, efficiency, and maximizing competition.

3. ***What other market design issues and tradeoffs should RTOs/ISOs, stakeholders, and regulators consider when designing and implementing reforms to energy and ancillary services markets to increase operational flexibility?***

See ACP's principles for energy and ancillary services markets, discussed above.

4. ***What are the tradeoffs to consider in procuring flexibility in the energy and ancillary services markets versus the capacity market or another new shorter-term forward market construct?***

Generally, revenues should be greater in the products that are more accurate and focused on specific needs at specific times, rather than the crude "capacity" product which is a crude amalgamation of imprecisely defined needs. ACP agrees with NYISO's Dr. Nicole Bouchez: "We don't see that the right answer is to focus on capacity market compensation for flexibility because it's just not at the right time when we need it, and it's hard at that point to match sort of performance with what it is that was purchased."[38]

**Comments on October 12, 2021 Technical Conference**

**Panel 1: Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers**

1. ***Do any existing RTO/ISO energy and ancillary services market participation rules, supply offer rules, eligibility requirements, and relevant procedures encourage certain resources to offer into the market inflexibly (i.e., without reflecting the full range of their physical operating capabilities)? For example, are any changes to resource supply offer rules or uplift eligibility requirements needed to ensure resources submit physical offer parameters (e.g., notification time, minimum run time, ramp rates) that reflect their flexible capabilities? To what extent do RTOs/ISOs account for existing fuel limitations, like natural gas supplies, that have the potential to impact resource flexibility?***

Yes. For example, batteries have no start times or ramp rate limitations, and markets are only beginning to allow that full flexibility to be represented. Order 841 helped in this regard but there are many details in each of the systems that can limit full flexibility. As stated by ACP's Jason Burwen at the October technical conference, in "the California ISO we're sort of seeing a first window into this storage is being reflected in the software as infinitely flexible. That's good."[39] He continued, the "disconnect between

---

[38] October 2021 Technical Conference Transcript at p.75.
[39] *Id.* at p.87.

slower bidding rules and fast and frequent change in dispatch or potential dispatch instructions can impose significant costs on storage units with uneconomical awards."[40] The Commission should direct transmission providers to move towards much faster changes in bidding rules and other means of incorporating the full flexibility of various resources.

2. ***Do any existing RTO/ISO energy and ancillary services market rules exhibit an undue preference for certain resource types over other resource types? If so, please explain how and provide examples.***

Yes. For example, MISO's market rules flatly prohibit entire classes of Dispatchable Intermittent Resources from providing certain ancillary services.[41] This is not tied to any resource capabilities and should be considered *per se* discriminatory.

At a higher level, a great deal of computing power in current RTO/ISO software is devoted to accommodating the operational limitations (which become "non-convexities" in the optimization) of conventional generation. That is an implicit subsidy for these resources. It would be better for consumers if that scarce computing power were devoted to a broader set of resources on a non-discriminatory basis.

3. ***To what extent do existing self-scheduling or self-commitment rules in RTO/ISO markets reduce the amount of operational flexibility available to the RTO/ISO in real time and the system's need for operational flexibility? Are options for self-scheduling and self-commitment needed to allow resource owners to make the best use of their assets over time?***

Self-commitment and dispatch can reduce the amount of operational flexibility provided to RTO/ISOs and can also change reserve needs to account for contingencies of these inflexible self-committed generators. Actions by states sometimes enable this inefficient behavior.

---

[40] *Id. at* p.88.
[41] MISO OATT, Section 39.2.1B.

For example, in SPP this has resulted in significant curtailment of wind energy which (absent self-scheduled resources) would have reduced costs and offered more flexibility to the system. SPP has investigated this issue, and its report unambiguously recommended that SPP and its stakeholder should, "work to reduce the incidence of self-commitments" to "improve price formation and market efficiency."[42] Coal units are the majority of self-committed resources in SPP, primarily they are relatively inflexible and cannot be turned on and off or ramped up and down quickly. Although some wind resources are also self-committed in SPP, these self-commitments result in essentially no impact on flexibility and production costs. As Joseph Daniel explained in his written submission, this is because the P-min (or economic minimum, described above) for wind is set at zero meaning that it can be flexibly dispatched all the way down to being completely turned off – enabling delivery of the precise amount of energy needed in a given interval. This is not the case for coal resources that both cannot turn off *and* have Pmins ranging from 25-75% of their operating capacity. That means wind units can provide precise and flexible energy and ancillary services to meet grid needs, but energy from coal generators can only be procured in inflexible quantities – even where that increases costs.[43]

Betsy Beck from Enel North America, Inc., argued in her technical conference comments that, "parameters like P-min and minimum run times are other elements of energy market dispatch protocols that need to be examined to evaluate their bias towards conventional resources, and the impact that it's having on efficient pricing and flexibility. While these parameters were once necessary to run the market and solve for blocky resources, but continuing to solve around these characteristics we ultimately compensate resources for

---

[42] *Self-committing in SPP markets:Overview, impacts, and recommendations* at 7 (Dec. 2019), https://spp.org/documents/61118/spp%20mmu%20self-commit%20whitepaper.pdf.

[43] Written Statement of Joseph Daniel for Oct 12, 2021 technical conference at 4, available at https://www.ferc.gov/media/joseph-daniel-union-concerned-scientists-panel-1.

their costs of inflexibility."[44] ACP concurs with Ms. Beck's statement and echo her call for the Commission to require RTOs to ensure fairness in self-scheduling rules.

4. ***Do current RTO/ISO offer rules, market power mitigation practices, and reference levels prevent or discourage resources from including in their offers the additional costs, if any, that resources incur from being more flexible (e.g., longer-term wear and tear on natural gas resources due to increased cycling, battery warranty considerations, etc.)? Are such costs difficult to quantify? If so, please explain why. How should RTOs/ISOs review such costs to ensure that resources' energy and ancillary services supply offers are competitive?***

Yes, the full flexibility of all resources should be both allowed and encouraged through market incentives. Inverter-based resources are extremely flexible and fast responding, and that can be very valuable to the system.[45]

Additionally, the Commission should make sure that market power mitigation rules do not inefficiently (and likely unintentionally) hinder the provision of all of a resource's capabilities. As noted above, market power mitigation rules should not prevent storage resources from providing services if their opportunity cost is ambiguous. In many cases the opportunity cost is ambiguous for a storage resource using state of charge to provide a service now at the expense of not being able to provide a service in the future. Additionally, as the comments of the Hybrid Resource Coalition made clear, mitigation measures must be updated for hybrid resources that may be able to charge a storage component either from the grid or from a renewable energy component.[46]

---

[44] Betsy Beck. Oct 12, 2021 Technical Conference Tr. at 83.
[45] *See* NREL Study at 55-56.
[46] *See* Comments of the Hybrid Resource Coalition, Docket No. AD20-9 at 24-26 (Sept. 20, 2021), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=066908BF-5067-CE0E-B547-7C0868B00000

**Panel 2: Maximizing the Operational Flexibility Available from New and Emerging Resource Types**

1. ***Do existing RTO/ISO energy and ancillary services market rules, practices, or procedures prevent or otherwise obstruct relatively new and emerging resource types from fully participating in RTO/ISO markets and offering the operational flexibility they are technically capable of providing?***

Yes. For example, some regions have duration requirements that prevent renewable and storage resources from providing ancillary services, even though they are capable of providing those services for shorter periods of time.[47]

2. ***To what extent do existing RTO/ISO energy and ancillary services market rules require standalone variable energy resources to respond to dispatch instructions (e.g., curtailment)?***

    a. *To what extent are standalone variable energy resources technically capable of being "dispatchable?" Is there a distinction between being dispatched down and being curtailed?*

All inverter-based resources are curtailable and controllable in the downward direction. With some opportunity cost, their output can be held back in order to ramp up.[48] Downward dispatch is distinct from curtailment, because the former responds to a system need (such as a frequency deviation).

    b. *Under what circumstances can a standalone variable energy resource be dispatched up versus down?*

See above.

3. ***To what extent do resource capabilities vary amongst different classes and vintages of variable energy resources (e.g., newer vs. older wind turbine models, onshore vs. offshore wind, fixed-tilt vs. tracking solar, etc.) and do offer rules currently reflect such differences, if any?***

---

[47] *See* LBNL Report at 23-24.
[48] LBNL Report at 8.

Capabilities do vary by technology and with different vintages, so in general standards should not be retroactive. ACP's predecessor organization, AWEA, supported certain reliability standard improvements for wind turbines including prospective low voltage ride-through and reactive power capability.[49]

4. ***To what extent are emerging resource types, such as hybrids, storage resources, and distributed energy resource aggregations technically capable of providing existing ancillary service products or other reliability services? Acknowledging that some market rules are evolving due to Order Nos. 841[50] and 2222,[51] do current RTO/ISO market rules for ancillary services and other reliability services, such as eligibility requirements, align with these emerging resource types' capabilities?***

The principles of Order Nos. 841 and 2222 – that resources should be able to receive compensation for all services they are physically capable of providing - are very sound and helpful. However, they are high level and there are many details related to the participation of various existing and new resources that require attention. As noted above, storage and hybrid resources are capable of rapid response, but may have unique opportunity costs that current market rules do not properly account for or compensate.

5. ***What RTO/ISO energy and ancillary services market reforms could be adopted, if any, to ensure that new and emerging resource types are able to offer their full operational capabilities into RTO/ISO energy and ancillary services markets to help operators manage changing system needs?***

    a. *Would shortening the day-ahead market interval length increase the operational flexibility available from resources? What considerations (e.g., computing time) are important to consider when establishing the length of energy and ancillary services market intervals?*

---

[49] *See* Wind-Solar Alliance, *Customer-Focused and Clean: Power Markets for the Future* at 21, 45-46 (Nov. 2018), https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-full-report.pdf.

[50] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 83 FR 9580, 162 FERC ¶ 61.127

[51] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 85 FR 67094, 172 FERC ¶ 61,247

Yes, shortening interval lengths can help to increase the flexibility provided by resources and expand the pool of resources that can supply the service.[52]

> b. *RTOs/ISOs often require resources that provide ancillary services to be capable of doing so for a duration of 60 minutes. Does this eligibility requirement limit the pool of resources available to offer ancillary services into RTO/ISO markets? Would reexamining the need for this particular eligibility requirement present reliability concerns or raise other issues for operators? If so, please explain.*

There may be times that batteries do not have a full hour's worth of charge, but can provide valuable services for less than an hour. Similarly, for shorter time intervals wind and solar are better able to guarantee provision of a certain quantity of service.[53] More granular product definitions will allow valuable flexibility to be provided – and if an hour-long product is needed, it can and should be procured separately.

**Panel 3: Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs**

1. ***What are the challenges to incorporating uncertainty within the current RTO/ISO market software? For example, how can improvements in forecasting, the use of intra-day commitment processes that include a range of forecasts, or longer look-ahead commitment and dispatch horizons result in more efficient unit commitment and dispatch in real time?***

Uncertainty must be incorporated formally into dispatch algorithms. Probabilistic tools can be developed and incorporated into estimates of commitment and dispatch needs. Longer look-ahead commitment horizons should not subsidize inflexible resources by guaranteeing them payment if they are committed and not ultimately needed.

---

[52] LBNL Report at 23.
[53] *Id.*

2. ***Can changes to RTO/ISO unit commitment and dispatch software address the need to posture system resources optimally to meet expected and unexpected ramp and operational flexibility needs?***

    a. *How are these enhancements tailored to the expected magnitude of forecast errors in different time periods?*

Estimates of needs at different times should be made by the grid operator based on sound probabilistic tools. The quantity demanded will likely vary over time and do so more in the future with the current and future resource mix, compared to the past when the quantity was determined by the size of conventional generating units, which did not vary over time.[54]

    b. *How would multi-period dispatch modeling in the real-time market help address operational flexibility needs? What are the advantages and disadvantages of a binding as opposed to an advisory multi-period dispatch model?*

Multi-period dispatch modeling would likely be very helpful to optimize the use of resources including battery storage resources. A binding market can ensure delivery at different times.

    c. *What are the computational burdens associated with such modeling enhancements?*

ACP acknowledges the need for computing time and software development costs to improve RTO/ISO software systems. Some computation time can be saved by spending less on the characteristics of conventional resources, such as those that are likely retiring in coming years, and focusing on ensuring adequate capacity for future resources.

3. ***To what extent can software enhancements for modeling specific technology types (e.g., multi-configuration modeling of combined cycle units, storage, etc.) help address the system's changing operational needs?***

[54] *See* LBNL Report at 24-25.

It is not necessarily the case that the centralized software needs to optimize all technologies. In many cases, market participants can self-optimize their resources as long as products are well-defined and technology neutral.[55] Removing the implicit subsidies for older, inflexible units will increase efficiency.

4. ***Can multi-day-ahead markets or hour-ahead markets help address operational flexibility needs in RTOs/ISOs? What is the objective of such approaches, and are there potential drawbacks?***

Yes, multi-day-ahead markets may enable operators to lock in supply they might need, potentially allowing for higher penetrations of variable resources. Some regions such as MISO have difficulty coordinating maintenance outages. This phenomenon is an example of why capacity markets are sometimes too crude to support reliability, because the resources that are compensated for providing capacity are often unavailable when needed. Some type of market-based commitment in advance of one day ahead may be beneficial for consumers.

**Panel 4: Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty**

1. ***RTO/ISO reports and filings to the Commission indicate that at times operators take out-of-market actions to address net load uncertainty. What impacts do such actions have on price formation in RTO/ISO energy and ancillary services markets? How strong are those impacts, both in terms of individual instances of operator actions and in terms of more general effects on the efficiency of the markets?***

Out-of-market actions hinder transparency and worsen price signals for efficient short- and long-run behavior. The Commission should require RTO/ISOs to minimize uplift and incorporate needed operator actions into products and prices. ACP agrees with Gary

---

[55] *See* NREL Study at 56.

Cate of SPP who said, "“So the out of market actions, while they're there, and they ensure reliability, they're very opaque to the market. They lack the transparency from a participant perspective, and they potentially create pricing distortions due to the excess supply that's on the grid.”[56] Energy storage resources in particular may be subject to significant opportunity costs due to exceptional dispatch instructions that require them to remain at a particular state of charge, rather than participating in energy markets. If this instruction is necessary to meet a reliability need, it should be defined as a service, and resources should be compensated accordingly. As noted above, shadow pricing may be appropriate to ensure indifference between supplying energy or ancillary services needs.

2. ***Do RTOs/ISOs anticipate that, without RTO/ISO market reforms, out-of-market operator actions will increase over time in response to changing system needs?***

OOM actions have been increasing and the comments from RTO/ISOs in the technical conference suggest there are many reasons (“So what we saw is as our forecast generation penetration grew, so did the out of market actions that our operators were taking”[57]). Most of these reasons can be incorporated into products and prices, and that should be done wherever possible. ACP recognizes it may not be feasible to fully eliminate out of market actions, but they can doubtless be reduced and made more transparent in the (hopefully rare) instances where they are still needed.

3. ***To what degree, if any, do out-of-market actions by operators undermine RTO/ISO energy and ancillary services market reforms, such as operating reserve demand curve reforms or ramp products, designed to incent resources to provide RTO/ISO operators with the operational flexibility needed to manage the system?***

---

[56] September 2021 Technical Conference Transcript at p. 132.
[57] *Id.*

OOM actions hinder efficient price formation. That harms both short-term behavior and long-term investment. ACP expects that well-designed products and price formation rules will lead to minimal need for out of market actions and minimal uplift, even as system net load variability increases in the future.

4. ***How can RTOs/ISOs best mitigate the risks of out-of-market operator actions undermining incentives for resource operational flexibility, to the extent such risks exist?***

Every out-of-market action should be reviewed to determine how it might be incorporated into products and prices.

## III. CONCLUSION

The Commission's 2021 technical conferences and this proceeding are extraordinarily important, and ACP appreciates the opportunity to provide these comments. With a dramatically shifting resource mix, it is essential to critically evaluate the products that energy and ancillary services markets procure, as well as the implicit assumptions that inform those markets and products today. This inquiry can provide the basis to remove implicit subsidies for inflexibility, procure energy and ancillary services in the form and at the time they are most valuable, and ensure reliability throughout the transition to a cleaner electricity system. ACP and its members look forward to continued engagement with the Commission on these vital topics.

Respectfully submitted,

Gabe Tabak
Counsel
Jason Burwen
Vice President, Energy Storage
American Clean Power Association
1501 M Street, NW, Suite 900
Washington, DC 20005
(202) 383-2500
gtabak@cleanpower.org
jburwen@cleanpower.org

February 4, 2022