UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Integration of Variable Energy Resources	)	Docket No. RM10-11-000

COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION

The Electric Power Supply Association ("EPSA")[1] respectfully submits the following comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") November 18, 2010 Notice of Proposed Rulemaking ("NOPR") regarding the integration of Variable Energy Resources ("VERs").[2] The NOPR proposes a limited set of reforms to existing market and operational procedures that derive from the earlier Notice of Inquiry in this proceeding.[3] Specifically, the Commission proposes the following reforms intended to remove barriers to VERs integration: (1) transmission providers must offer fifteen-minute intra-hourly scheduling; (2) interconnection customers with VERs generation must provide meteorological and operational data to transmission providers; and, (3) transmission providers must provide a new generic Ancillary Service rate schedule (called "Generator Regulation Reserves Service").[4]

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[1] EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.

[2] *Integration of Variable Energy Resources,* 133 FERC ¶ 61, 149, Docket No. RM10-11-000 (November 18, 2010) ("VERs NOPR").

[3] *Integration of Variable Energy Resources,* 130 FERC ¶ 61,053 (2010) ("VERs NOI").

[4] VERs NOPR at 2.

The Commission has determined that certain proposals from the more wide-ranging VERs NOI are not ready to move forward and require further study and recognizes that other industry efforts with respect to VERs integration issues are underway and intends to complement those initiatives with the "foundational reforms" proposed in the NOPR.[5] While EPSA understands the Commission's rationale for taking an incremental approach in considering issues surrounding the integration of VERs, EPSA is very concerned that as one of these first steps, the NOPR does not sufficiently hone in on the ramp capability issue,[6] focusing solely on the Regulation market, and thereby overlooking a significant market consideration that must be addressed if VERs are to be reliably integrated. Accordingly, because the NOPR's focus is too narrow and does not consider the ramping issue in sufficient breadth, EPSA has identified as a primary concern that, as proposed, the Generator Regulation Reserves Service may have unintended adverse consequences for generation resources required to provide support for reliable integration of VERs outside of the Regulation market, and therefore, may be unjust, unreasonable and unduly discriminatory.

To allow for additional focus on this critical issue, EPSA requests that, prior to issuance of a Final Rule, the Commission convene a Technical

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[5] Among other things, EPSA's earlier Comments on the VERs NOI urged the Commission "to use this proceeding as a vehicle to require more comparability between RTO and non-RTO market requirements, for example, by requiring enhanced forecasting, intra-hour scheduling and consolidation of balancing areas within the non-RTO regions." See *Comments of the Electric Power Supply Association* at 10, Docket No. RM10-11-000 (filed April 12, 2010) ("EPSA VERs NOI Comments"). Available at www.epsa.org.

[6] EPSA VERs NOI Comments at 11: "In particular, EPSA believes the ISOs/RTOs should be encouraged to further articulate needs in managing and developing products that fully compensate and promote ramp capability to balance VERs. EPSA recognizes there has been some level of assessment on the capability needed, particularly to manage the morning and evening ramps. However, there remains a lack of transparency with regard to managing what can be excessive levels of ramping and drop-off that in turn is resulting in uneconomic out of market commitments by the ISOs/RTOs to meet this volatility risk."

Conference(s) to further develop the record on the market mechanisms and product development necessary across the non-RTO and RTO regions to reliably integrate large scale amounts of VERs as discussed in more detail herein. Finally, EPSA urges the Commission to consider the impacts of any regulatory changes in this proceeding within the broader context of the numerous policy proceedings and initiatives that the Commission currently has underway to ensure consistent and rational outcomes.

I. COMMUNICATIONS

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II. COMMENTS

As previously stated in response to the NOI, EPSA welcomes this rulemaking proceeding and the opportunity to provide comments given the significant impacts to EPSA membership of large scale VERs integration. EPSA members are operating across all the RTO and non-RTO regions, and are owners, operators, and/or developers of every type of generation resource and associated technologies, including investments in VERs, energy storage and carbon capture and storage ("CCS") projects. Therefore, EPSA supports allowing all resources to compete fairly to meet consumer needs within applicable environmental requirements. To that end, EPSA members have been active stakeholder participants in ISO/RTO and other industry initiatives to

identify barriers and develop solutions to successfully integrate VERs, as well as demand response and energy efficiency resources, and associated technologies into the markets under just and reasonable terms.

With that in mind, EPSA's overarching concern in this proceeding relates to any proposed reforms that might confer preferential treatment to a class of resource to achieve a desired policy outcome, but may instead or concurrently distort price signals, place uncompensated burdens on other resources or result in cost shifting, thereby producing inefficient market outcomes. As noted by Commissioner LaFleur, the "rulemaking seeks to adapt certain market and grid rules to ensure just and reasonable treatment of [VERs]. However, at the same time, it would place obligations on those variable resources to ensure that their operation does not affect other resources in an unjust or unreasonable manner."[7] EPSA agrees this is the appropriate goal of any reforms considered by the Commission for addressing any barriers to and the challenges of VERs integration.

Therefore, EPSA continues to urge a balanced approach by the Commission with respect to any potential regulatory changes in this proceeding, which should consider impacts to and fully optimize use of the existing generation and transmission infrastructure. The Commission currently has proceedings and initiatives at different procedural stages and/or utilizing different procedural vehicles that are addressing significant, intertwined policy issues affecting the integration of VERs, including, but not limited to: the Lawrence Berkeley National Laboratory Frequency Response Metrics Study; Staff Inquiry

[7] Statement of Commissioner Cheryl A. LaFleur on Integration of Variable Energy Resources NOPR, Docket No. RM10-11-000, November 18, 2010.

on Rates, Accounting and Financial Reporting for New Electric Storage Technologies; National Institute of Standards and Technology ("NIST") Smart Grid standards rulemaking process; the NERC Frequency Response Standards process; Bi-annual Assessments of Demand Response and Advanced Metering (Staff Reports); and the recently issued Proposed Rulemaking on Frequency Regulation Compensation in Organized Wholesale Power Markets.[8] EPSA believes regulatory changes to address these various policy goals or initiatives should occur in a coordinated manner to ensure consistent and rational outcomes, and further, the Commission should consider how any changes should extend to market related services provided by existing generating technologies within those proceedings.

Notably, traditional generation resources and their flexibility will be required as the primary support of system operation to reliably integrate VERs, and will play an important role under any large scale VERs integration scenario. The Commission must ensure non-discriminatory and fair treatment of all generation resources, as work continues to address the operational and technological changes necessary to meet ambitious national and state energy and environmental policy goals. Continued generation investments will be

[8] Lawrence Berkeley National Laboratory, *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation*, (December 2010); *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies,* Docket No. AD10-13-000, (June 11, 2010); *Smart Grid Interoperability Standards,* Docket No. RM11-2-000 and *Smart Grid Policy Statement,* 128 FERC ¶ 61,060, Docket No. PL09-4-000 (issued July 16, 2009); *Mandatory Reliability Standards for the Bulk Power System,* Docket Nos. RM16-010, -011; *Assessment of Demand Response and Advanced Metering Staff Report* (Staff Reports issued August 2006, December 2008, September 2009, and February 2011); and, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 134 FERC ¶ 61,124, Docket No. RM11-7-000 and AD10-11-000 (issued February 17, 2011).

required to support changing market needs, along with more complete definition of required products and services, and the markets need to properly value and compensate for such services and associated investments.

As noted above, EPSA requests that the Commission convene a Technical Conference prior to issuance of a Final Rule to allow for further development of the record on the products, services and technologies needed to reliably integrate VERs across the ISO/RTO and non-RTO regions and whether, and if so the extent to which, existing market mechanisms sufficiently compensate and incent such services to support the large scale amounts of VERS envisioned.[9]

While the VERs NOPR appropriately considers the additional demands on system response capability introduced by integration of VERs, the focus solely on Regulation Service (through the proposed Generator Regulation Reserves Service) appears to overlook the importance of economic dispatch control in ISOs/RTOs which currently performs the bulk of ramping to balance the system, with Regulation Service only addressing the residual, fine adjustments and occasional, immediate responses to system contingencies. Just as the Lawrence Berkeley Frequency Response Metrics Study highlighted the

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[9] In the NOPR at P 100, the Commission seeks comments from NERC and industry stakeholders on the extent to which some additional type of contingency reserves (beyond the services provided under Schedule 5 and 6 of the pro forma OATT) "would ensure that VERs are integrated into the interstate transmission system in a non-discriminatory manner while remaining consistent with NERC reliability standards." EPSA's earlier VERs NOI comments had generally raised concerns and commented on the need for ISOs/RTOs to develop products that value and better manage what can be excessive levels of ramping in the morning and evening, and is resulting in uneconomic out of market commitments by the ISOs to meet this volatility risk. Consistent with those earlier comments, EPSA notes here that the ISO/RTO system response needs to accommodate VER integration are broader than just Regulation service. A Technical Conference would facilitate dialogue on possible solutions.

importance of assuring adequate secondary frequency control reserves,[10] it is equally important to focus on all components of secondary frequency control. ISOs/RTOs generally require only small quantities of Regulation capability since such quantities are only needed to perform the fine system balancing to control Area Control Error corrections in seconds after the bulk of system balancing is accomplished through economic dispatch of generation resources every five minutes (referred to for purposes for these comments as "economic generation control").[11] As a result, significantly more demands are placed on the system ramping accomplished through economic generation control.

Existing ISO/RTO markets provide limited incentives for such ramp capable investments, with capacity and energy markets providing no distinction between resources, including no compensated distinction between those providing little or no ramping capability from those which provide significant ramp capability, but do so outside the Regulation market. Maintaining and indeed increasing such ramping capability will become more pressing going forward as older units that are capable of providing ramp retire in response to upcoming enhanced environmental requirements and lower energy prices resulting, in part, from the introduction of large quantities of VERs. A Technical Conference would improve the record to understand the broader ramping needs beyond just

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[10] Lawrence Berkeley National Laboratory, *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation,* Item 4 at Page XXV, (December 2010). ("The demands placed on slower forms of frequency control, called secondary frequency control reserves, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation.")

[11] ISO/RTO changes to generation dispatch accommodates changes in load as well as changes in net interchange schedules between adjacent control areas.

Regulation Service and the insufficiency of market incentives to attract that particular capability.

A. Fifteen-Minute Intra-Hourly Scheduling

EPSA strongly supports the Commission's proposed reform to require transmission providers to offer more frequent scheduling, at fifteen minute intervals, within each operating hour.[12] Importantly, EPSA considers fifteen minute intra-hour scheduling as a necessity that must be a linked requirement to the proposed Generator Regulation Reserves Service. In general, by requiring more frequent adjustments to schedules, the Commission is facilitating additional liquidity, as well as consistency, primarily in the non-RTO (or bilateral market) regions of the country, as the ISO/RTO regions already provide intra-hour scheduling at the required intervals or even more frequent intervals.

The availability of fifteen-minute intra-hour scheduling would provide benefits to the non-RTO regions as they integrate increasing amounts of VERs, as more frequent scheduling opportunities will expand the availability of flexible generation resources and demand response resources to provide necessary support. Given that the proposed fifteen minute interval is consistent with the NERC recommendations for achieving greater flexibility while meeting relevant reliability requirements,[13] EPSA urges the Commission to move forward with adoption of this proposed reform by a date certain for all transmission providers.

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[12] VERs NOPR at PP 19, 25-44.

[13] *See* North American Electric Reliability Corp., *Accommodating High Levels of Variable Generation* at 17-18, (issued April 16, 2009) ("IVGTF Report"); VERs NOPR at P 37.

B. Generator Regulation Reserves Service Impacts In Non-RTO Regions

A central issue of the NOPR from EPSA's perspective relates to the proposed new Ancillary Service, Generator Regulation Reserves Service,[14] and its application in the non-RTO regions. Specifically, the Commission proposes to establish a generic rate schedule (Schedule 10) to provide a mechanism for transmission providers to recover the costs of holding regulation reserves capacity to meet system variability.[15] Proposed Schedule 10 is modeled on Schedule 3 (Regulation and Frequency Response Service) of the *pro forma* Open Access Transmission Tariff ("OATT"), and contemplates a charge that is the product of two components: a per-unit rate for regulation reserve capacity and a volumetric component for regulation reserve capacity.[16] The NOPR states that, "As a general matter, the Commission agrees that regulation reserve costs should be allocated to transmission customers consistent with cost causation principles."[17]

EPSA has several concerns with the new service as currently articulated. First, the NOPR includes language that would appear to provide an opportunity for a transmission provider to obtain a waiver from the fifteen minute intra-hour scheduling requirements,[18] which as EPSA has noted above, the fifteen minute intra-hour scheduling would offer benefits to transmission providers in managing

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14 VERs NOPR at PP 66-100.

15 Id. at PP 88-95.

16 Id. at PP 88 and 92.

17 Id. at P 94.

18 Id. at PP 105-106.

VERs integration and is a scheduling timeframe consistent with NERC recommendations.[19] Second, while the Commission is correct in considering a new service that facilitates reliable integration of VERs, the NOPR does not sufficiently address the lack of market mechanisms available to conventional generation resources in the non-RTO regions, who have the ability to meaningfully contribute to VERs integration, but in non-RTO areas have neither the opportunity to do so nor the opportunity to be compensated for doing so.

As discussed above, the fifteen-minute intra-hour scheduling should be a prerequisite to the implementation of the Generator Regulation Reserve service in non-RTOs, as tightening the scheduling periods will assist in addressing potential conventional generator exposure to additional charges under this new service. Absent the fifteen-minute intra-hour scheduling, the proposed Generator Regulation Reserve service will never be able to reflect the opportunity costs associated with thermal plant operations start-ups, shut-downs and ramping, and may trigger associated costs for these existing resources. Aggregating four dispatch periods within the hourly settlement period should help reduce the potential exposure to penalties or additional unintended costs.

While EPSA supports the more granular intra-hour scheduling, EPSA believes it is important to retain hourly settlement periods, given the variability that can occur within each hourly interval, based on specifications and requirements of existing interconnection agreements. Many interconnection agreements have a penalty for variations outside of a "set point" band, so there

[19] EPSA recognizes that not all regions of the country anticipate significant levels of VERs; however, such flexible scheduling is currently available in organized wholesale electric markets and provides additional overall benefits in terms of the markets ability to respond to changing events and should be implemented.

are already levels around which many conventional generators are scheduling output. Therefore, EPSA respectfully requests clarification that the Commission will require transmission providers to offer **both** intra-hour scheduling and the new Generator Regulation Reserves Service as linked requirements, otherwise EPSA submits the new Ancillary Service proposal is unjust, unreasonable, and unduly discriminatory.

Importantly, EPSA submits that its members could be a bigger part of the solution in the non-RTO regions; however, under current tariff and business practices, they are not fully able to participate in the provision of services that would assist in the reliable integration of VERs. For example, the Commission should also require the transmission provider to competitively acquire the new Generator Regulation Reserves Service from all generators in the balancing authority area, rather than assuming the transmission providers own generation is the only generation that can provide the service. EPSA suggests that possible market mechanisms and other competitive options for integrating VERs in the non-RTO regions should be considered as part of the Technical Conference that EPSA has requested in this proceeding. Finally, EPSA suggests that prior to issuance of a final rule the Commission also consider the cost causation issue during the requested Technical Conference(s) to further develop the record.

C. Generator Regulation Reserves Service Impacts In ISO/RTO Regions

With respect to providing the Generator Regulation Reserves Service in the ISO/RTO regions, EPSA generally notes that while this new rate schedule would not appear to raise any significant operational issues, this is true because the ISOs/RTOs accomplish the majority of their system balancing through

economic dispatch control of generators through a least cost dispatch performed every five minutes, which allows for more precise load-following capability. (Again, for purposes of these comments, economic dispatch control of generating resources is referred to as "economic generation control"). So, from an operational perspective, ISO/RTO scheduling is already more flexible than the fifteen-minute scheduling proposed under the VERs NOPR. However, the consideration of increased ramping demands which may arise with increased VERs integration appears to incorrectly presume that only Regulation Service requirements will increase with increased magnitude in VERs variable output changes, or that hourly energy imbalance markets will sufficiently incent increases in the complementary generator ramp capability needed for economic generation control. In weighing the possible effects of the Generator Regulation Reserves Service on the ISO/RTO markets, EPSA believes the proposed service is too narrow in addressing current market design and operational changes that are required. Specifically, EPSA notes that (1) the absence of compensation or incentives for economic generation control as a service or product does not assure sufficient response capability in real time dispatch to accommodate significant changes in supply/demand variability;[20] and, (2) general application of

[20] New England Wind Integration Study Summary (November 2010) at pgs. 7-8 states "*Region needs to maintain a flexible system*

- Any conditions that reduce the system flexibility may potentially, negatively impact the ability of New England to integrate large amounts of wind power.
- The balancing of net load—essential for large-scale wind integration—was seen largely being provided by the flexibility of the region's natural-gas-fired generation fleet. If future displacement of natural-gas-fired generation by wind energy is such that there is attrition of these types of flexible resources, the need for supplemental payments for flexible resources and/or energy storage technologies may increase.

Generator Regulation Reserves Service cost responsibility to generator output changes would be misplaced. To illustrate these points, EPSA provides a brief review of the ISO/RTO market basics.

1. Operations of the Current RTO Markets and Shortfall in Market Design and Incentives

ISO/RTO markets generally rely on Day Ahead Energy Markets ("DAEM") to develop the next day commitment schedule of generators which will be brought on line to support the next day load (and variations in load) as forecasted through cleared DAEM demand bids. Where DAEM cleared demand levels in combination with net cleared virtual bids would lead to a situation where insufficient generation would be committed to meet next day needs, the ISO/RTO performs its own assessment of next day needs and commits additional generators as necessary to assure reliable service next day load.[21]

In real time dispatch, the ISO/RTO issues dispatch directions every five minutes to rebalance supply and demand through changes in economic dispatch levels for each. While this process generates five minute marginal prices for energy, they are ultimately combined to form a single weighted hourly average Locational Marginal Price ("LMP") for energy. These real time LMP prices are

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> • The addition of large-scale wind generation, with its characteristic low operating costs, would reduce wholesale electric energy market revenues for all resources, but would reduce revenues for some more than others. It is unclear, given the large decrease in energy market revenues for natural-gas-fired resources, whether these units would be economically viable, under current market conditions and, therefore, continue to be available to supply system needs under this scenario. As wind penetration increases, the market design may need to evolve to incent resources to provide the flexibility required to balance net load and dispatchable resources. "

[21] For example, where the ISO/RTO commits additional resources beyond those committed in the DAEM, it is possible that their as-bid costs may not be fully recovered through the Real Time Energy Market LMP payments and these residual costs must be uplifted through Net Commitment Period Costs (ISO New England) or Bid Production Cost Guarantees (New York ISO).

paid to weighted average hourly generation output not sold at the DAEM LMP. Net generation that remained at a static level in the hour (no ramping), net generation that moved in a direction increasing the imbalance (e.g., possibly VERs), and net generation ramping to provide the desired interval balancing service, all receive the same real time LMP.[22] Hence, despite ISO/RTO tariff schedules referencing these energy market payments as Energy Imbalance Service, the LMP payments provide no specific compensation or incentive to maintain and attract the ramping flexibility needed by the RTO to perform economic generation control rebalancing of the system every five minutes. In fact, good economic generation control performance has over time allowed RTOs to reduce the size of Regulation Service requirements.[23] In the absence of specific compensation or incentives to reward economic generation control, this relationship actually decreases the effectiveness of the Regulation Service market to encourage ramp capable generators as compensated Regulation Service ramping is displaced by economic dispatch control which provides the bulk of system balancing ramp capability, without explicit compensation or incentive.[24]

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[22] This outcome seems inconsistent with the Commission's observation in its NOPR on Frequency Regulation Compensation that resources providing more ramping in the Regulation market should be adequately compensated for their ramping service. In the NOPR, the Commission proposes a mileage form of payment to make this distinction. However, it is no less important to adequately incent the provision of ramping capability in the economic dispatch. *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 134 FERC ¶ 61, 124, Docket No. RM11-7-000 and AD10-11-000 (issued February 17, 2011).

[23] For example, see, ISO New England 2009 Annual Markets Report at pg. 124, "The average annual Regulation requirement has been steadily decreasing from 181 MW in 2002 to 89 MW for 2009."

[24] As an example, while the ISO-NE Forward Capacity Market compensates all resources at the same clearing price, the product sale obligation differs based on the design capabilities of the resource making the sale. A resource, demand resource, generator or import, which is not ramp

EPSA urges the Commission to hold a Technical Conference for the purposes of discussing this shortfall in market design and address the need for market incentives to retain the ramping capability needed to address current system variability and attract additional ramping capability as needed to address integration of large amounts of VERs.

2. General Application of Generator Regulation Reserves Service Cost Responsibility to Generator Output Changes Would Be Misplaced

Further, EPSA is concerned that creating the possibility for allocating some portion of Generator Regulation Reserves Service costs generally to all generator output variations through a new rate schedule could inadvertently apply Regulation Service costs to resources not causing such costs to be incurred. Most changes in energy schedules (imports or generator output changes) are ISO/RTO scheduled changes to address load ramp up and ramp down, address changes in hourly intertie schedules, and respond to system contingencies. That is, the ISO/RTO routinely changes generator energy schedules each five minutes in a least cost dispatch in light of other changes on the system. Even market participant initiated self-scheduled changes in generator output require some advance notice to the ISO/RTO and permit the ISO/RTO to deny the request as required to maintain reliability and address the requested ramp change through economic dispatch control (i.e., economic generation control). Since most changes in generator output schedule are either ISO/RTO directed and self-directed changes (i.e., self-scheduled) and are balanced with economic generation control, it is unclear why generator deviations

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capable may displace the purchase of a ramp capable generator, yet, a capacity sale by the ramp capable generator will require the provision of that ramp service in the energy market without any explicit compensation for that premium service.

generally should be held responsible for any Regulation Service costs and equally unclear why economic generation control ramping should not be explicitly incentivized. Additionally, such charges would perversely incentivize generators to remove additional ramping capability in order to stay closer to dispatch set point and avoid penalties. Decrease of generator ramping ability would in fact be counterproductive and would contribute to an overall loss of system flexibility, commonly known as a loss of system "headroom." EPSA requests that, prior to issuance of a final rule, the Commission also consider the cost causation issue during the requested Technical Conference(s) to further develop the record.

D. The Commission Should Convene A Technical Conference(s) To Discuss That Overall System Response Needs To Accommodate VERs Integration Are Broader Than Just Regulation Service

While the discussion above identifies the importance of economic generation control in balancing the system in response to changes in demand and other variability on the system (including variability introduced by large scale integration of VERs), EPSA is concerned that the existing ISO/RTO markets do not provide the compensation or incentive necessary to retain and attract the ramping capabilities that will be required. In addition to the increased demand for ramping capability that may be precipitated by VERs integration, other factors such as expected environmental regulations may affect the economics of certain existing ramp capable resources and decrease supply. In order to assure an efficient mix of resource capabilities, it will be important to provide the necessary price signals to those generators who add benefits to the system, including ramp capability. EPSA provides a general inventory of the existing ISO/RTO markets

and services to highlight this shortfall and believes this is instructive for further consideration of market design changes that may be needed:

1. Capacity Market

ISO/RTO capacity markets generally consider each resource as a substitute for every other resource, yet the system requires various capabilities not provided by every resource. As an extreme example, EPSA highlights the ISO-NE Forward Capacity Market ("FCM") where a behind the meter generator at an end customer site can be sold as Real Time Demand Resource which can generally only be scheduled by ISO-NE after the system experiences a sustained shortage in operating reserves. As a result, this limited access resource can displace the purchase of flexible generating resources needed to meet ISO-NE economic generation control needs. While the FCM, to date, has been able to retain existing generation flexibilities under the initial floor price period, it is unclear what will happen when the floor price is removed or demand for generator ramp increases.

The fact that the FCM requires vastly different capacity service provided upon capacity sale by these resources means that either the FCM cannot reflect the value of the more rigorous service offering or it will overpay for the less rigorous service.[25] Because all capacity clearing in the FCM receives the same price, there is no opportunity for resources with ramping capability to receive additional compensation that reflects such enhanced capability.

[25] Where the clearing price for a product like capacity permits resources incapable (or not required) to provide economic generation control, while competing products which can provide economic generation control are required as a condition of capacity sale to do so, the clearing price cannot adequately value the more rigorous product, as the product price is moderated by the presumably lower costs of providing less service.

2. Energy Market

As detailed above, in most organized markets (the New York ISO settles every five minutes) the energy market pays integrated hourly generation the same integrated hourly LMP whether the resource provides no ramping in the hour (i.e., static schedule), ramping in the wrong direction (e.g., VER ramp down during morning load ramp up), or economic generation control ramping. As a result, the energy market compensation also fails to provide specific compensation for ramping capability.

3. Real Time Operating Reserve Market[26]

Some RTOs provide compensation for operating reserve provided in real time. Generally, the payments are only made where either (1) there is a shortage of operating reserve, or (2) the redispatch to meet operating reserve requirements requires certain generators to be dispatched below their economic generation level where they incur lost opportunity costs.

Even where ISO/RTO tariffs include Ancillary Service products such as operating reserves and supplemental operating reserves which provide some compensation for availability and some compensation for actual deployment, these contingency protection reserves only reflect a subset of the ramp required to efficiently operate the system and such Ancillary Service products are not a substitute for adequate system ramping capability. Individual generator ramping ability, also known as load following capability, is needed both to meet normal

[26] Of note, ISO-NE has a Forward Operating Reserve Market that procures ten minute non-spinning reserve and thirty minute reserve to cover a portion of the first and second contingencies for the region, and most of the second contingencies in import constrained zones.

system ramping needs and to replace operating reserve upon activation of operating reserve procured on a forward basis.

4. Regulation Market

Regulation Service ramping is the residual fine tuning of the system frequency accomplished after the heavy lifting ramp service is accomplished through economic generation control. The purpose of Regulation Service is specifically to maintain system frequency as close to 60 Hertz as possible. ISOs/RTOs rely on load following via five minute generation dispatches to keep Regulation Service requirements low, thus keeping the number of megawatts of ramping capability compensated as Regulation Service minimal. While the total effective ramping capability translates into additional system flexibility, or additional system "headroom," and additional headroom makes integration of a higher level of VERs possible, there is currently no explicit compensation or incentive to retain or attract optimum ramping capability outside of the Regulation Market.

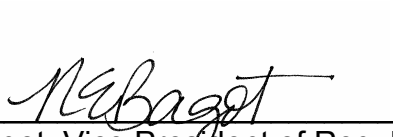
In summary, EPSA reiterates its concern that the NOPR focuses too narrowly on the Regulation market and accordingly, does not properly focus on the full range of products and services that will be needed to ensure sufficient ramping capability is available to reliably support VERs. EPSA notes that nowhere in the VERs NOPR is there a discussion of the general ramping capability that may be necessary. Given the importance of this issue, EPSA urges the Commission to schedule a Technical Conference(s) to explore possible market mechanisms and services to address ramping needs more broadly with

the ISOs/RTOs, transmission providers, market participants and other interested stakeholders prior to issuing a Final Rule in this proceeding.

III. CONCLUSION

Wherefore, EPSA respectfully requests that the Commission consider the recommendations herein, including scheduling a Technical Conference(s) to allow for further discussion, record development and technical analysis of the NOPR issues prior to issuance of a Final Rule. EPSA submits additional consideration is required regarding the products, services and technologies needed to reliably integrate VERs in both the ISO/RTO and non-ISO/RTO regions while fully optimizing use of the existing generation and transmission infrastructure necessary to support such integration.

Respectfully Submitted,



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March 2, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the comments via email upon Each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. March 2, 2011.

Nancy Bagot, VP of Regulatory Affairs