UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF ISO/RTO COUNCIL

The ISO/RTO Council ("IRC")[1] submits the following comments in response to the Federal Energy Regulatory Commission's ("Commission") November 18, 2010 Notice of Proposed Rulemaking regarding Integration of Variable Energy Resources.[2] The IRC supports the Commission's efforts to address challenges to the integration of variable energy resources ("VER"); however, the IRC cautions the Commission that the some of its NOPR proposals and the proposed compliance deadlines are problematic and should be reconsidered. The Commission should instead allow transmission providers to develop just and reasonable mechanisms to integrate VERs without negatively impacting

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1 The IRC is comprised of the Alberta Electric System Operator ("AESO"), the California Independent System Operator ("CAISO"), Electric Reliability Council of Texas ("ERCOT"), the Independent Electricity System Operator of Ontario, Inc., ("IESO"), ISO New England, Inc. ("ISONE"), Midwest Independent Transmission System Operator, Inc., ("Midwest ISO"), New Brunswick System Operator ("NBSO"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and Southwest Power Pool, Inc. ("SPP"). The AESO, IESO, and NBSO are not subject to the Commission's jurisdiction, and these comments do not constitute agreement or acknowledgement that they can be subject to the Commission's jurisdiction. ERCOT is not subject to the Commission's jurisdiction with respect to the issues presented in this NOPR, but is joining in support of the IRC comments. The IRC's mission is to work collaboratively to develop effective processes, tools, and standard methods for improving the competitive electricity markets across North America. In fulfilling this mission, it is the IRC's goal to provide a perspective that balances Reliability Standards with market practices so that each complements the other, thereby resulting in efficient, robust markets that provide competitive and reliable service to customers.

2 *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, IV FERC Stats. & Regs., Proposed Regs. ¶ 32,664 (2010) ("NOPR").

the reliability of the integrated transmission system, and should afford transmission providers sufficient time to do so.

I. BACKGROUND & SUMMARY OF COMMENTS

On January 21, 2010, the Commission issued a Notice of Inquiry regarding Integration of Variable Energy Resources,[3] requesting comments addressing the extent to which barriers exist to the integration of VERs into the electric grid and whether reforms are needed to eliminate such barriers. On April 13, 2010, the IRC submitted a White Paper providing extensive comments on existing efforts among Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO") to address the integration of VERs into RTO and ISO administered transmission systems and markets.[4] The Commission received comments from more than 135 entities in response to the VER NOI.[5]

The Commission issued the NOPR on November 18, 2010, proposing to:

(1) Amend the *pro forma* Open Access Transmission Tariff ("OATT") to require public utility transmission providers to provide transmission customers the option of utilizing intra-hour scheduling on a 15-minute interval basis;[6]

(2) Amend the *pro forma* Large Generator Interconnection Agreement ("LGIA") to incorporate provisions requiring interconnection customers whose generating facilities are VERs to provide meteorological and

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

[4] Correction of Comments of the ISO/RTO Council in Response to the Federal Energy Regulatory Commission's Notice of Inquiry Seeking Public Comment on the Integration of Variable Energy Resources, Docket No. RM10-11-000 (Apr. 13, 2010) ("IRC White Paper").

[5] NOPR at P 11.

[6] NOPR at P 37.

operational data to public utility transmission providers utilizing VER power production forecasting tools;[7] and

(3) Amend the *pro forma* OATT to add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service, and require public utility transmission providers to offer generator regulation service to the extent it is physically feasible to do so from its resources or resources available to it for transmission customers using transmission service to deliver energy from a generator located within a public utility transmission provider's balancing authority area.[8]

The Commission also proposed to require each public utility transmission provider to submit a compliance filing within six months of the effective date of the final rule issued in this proceeding.[9]

The IRC offers the following comments:

- The Commission should recognize that different regions currently provide varying levels of flexibility to VERs through different systems and market mechanism and should refrain from adopting a national intra-hour scheduling requirement; instead, the Commission should craft the final rule in a manner that affords regional flexibility to allow transmission providers to work with their stakeholders to develop solutions that work for their region**;**

- Power production forecasting tools are useful in managing VER variability and the IRC supports the Commission's proposal to permit transmission providers utilizing forecasting tools to require VER interconnection customers to provide certain meteorological and operating data (including VERs that are already in service); and

- The IRC concurs with the Commission's proposal to allow transmission providers to recover the costs of providing generator regulation service through a new Schedule 10 to the *pro forma* OATT.

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7 NOPR at PP 60-61.

8 NOPR at PP 85-89.

9 NOPR at P 101.

II. COMMENTS

The IRC believes that integrating vast amounts of new variable renewable resources in a reliable manner presents significant challenges, and RTOs and ISOs have made significant strides in facilitating VER integration, as discussed extensively in the IRC White Paper.[10] The Commission should afford transmission providers flexibility to adopt just and reasonable mechanisms to accommodate VERs without mandating changes that fail to recognize regional differences in VER potential, system capabilities, and market designs. The Commission also should clarify in the final rule whether the VER integration requirements the Commission adopts apply to non-jurisdictional transmission providers operating under reciprocity OATTs.[11]

A. Intra-Hourly Scheduling

The Commission proposed to amend Sections 13.8 and 14.6 of the *pro forma* OATT to provide transmission customers the option to schedule transmission service on an intra-hour basis at intervals of 15 minutes.[12] The Commission also proposed to require transmission providers to allow transmission customers the option of submitting intra-hour schedules up to 15 minutes before the scheduling interval.[13]

While the IRC supports the Commission's desire to facilitate the integration of VERs into transmission systems and markets, the NOPR proposes a significant paradigm

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[10] IRC White Paper, *passim*.

[11] NOPR at P 104 ("The Commission proposes that transmission providers that are not public utilities will have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.") (citations omitted).

[12] NOPR at P 37.

[13] NOPR at P 41.

shift that may create major compliance challenges for some transmission providers and may potentially result in considerable unintended consequences. While RTO and ISO systems are comparatively sophisticated and many RTO systems and markets already provide significant flexibility for VERs, whether through intra-hour scheduling or other market mechanisms, the IRC is concerned about the proposed nationwide mandate that all transmission providers modify their existing systems at an accelerated rate.

As the NOPR recognized,[14] VER penetration levels vary significantly in different regions across the country. Likewise, the ability of transmission providers and markets to accommodate intra-hour scheduling varies widely, as does the need to implement intra-hour scheduling given varying levels of VER potential and the existence of other potential mechanisms to address resource variability. Accordingly, the Commission should allow each transmission provider to determine the most appropriate methods to provide flexibility to VERs based on the relative level of VER penetration, system capabilities, and market structures present in the transmission provider's region.

Moreover, because changes to accommodate VERs on one transmission system may impact neighboring transmission systems, the Commission should allow transmission providers sufficient time to address VER integration issues with neighboring transmission providers in their region. The IRC is concerned that some RTOs and ISOs engage in significant interchange with areas without organized markets and with small balancing authorities. Mandating accelerated changes to inter-hour scheduling could result in significant negative consequences for RTOs and ISOs engaged in interchange

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14 *See* NOPR at P 55 (recognizing that there are "areas of the country with very limited production from VERs").

with non-market areas and smaller balancing authorities that simply cannot keep up with intra-hour scheduling with the RTO or ISO.

Likewise, the NOPR proposal to allow transmission customers to modify schedules up to 15 minutes prior to the scheduling interval could be problematic for some transmission providers, who will need to engage in significant system changes and hire and retain additional personnel to enable the transmission provider to accept, review, and approve all scheduling changes that are submitted by transmission customers prior to the scheduling interval. As the Commission acknowledged, schedules are currently set typically between 20 and 30 minutes ahead of the scheduling interval.[15] Allowing changes up to 15 minutes before a scheduling interval may not be feasible for some transmission providers under current system and personnel constraints.

For the variety of reasons cited above, the Commission should reconsider its proposed nationwide mandate for intra-hourly scheduling and, instead, craft the final rule in a manner that affords regional flexibility to allow transmission providers to work with their stakeholders to develop solutions that work for their region.

B. Power Production Forecasting and Data Reporting

While preliminarily finding that "power production forecasting can play a significant role in removing barriers to the integration of VERs into the transmission system,"[16] the Commission proposed not to mandate the implementation of power production forecasting. Instead, the Commission proposed to require deployment of power production forecasting tools by transmission providers that seek to require a subset

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15 NOPR at P 26.

16 NOPR at P 55.

of transmission customers to purchase, or otherwise account for, different volumes of generator regulation reserves.[17] The Commission also proposed to revise the *pro forma* LGIA to require VER interconnection customers to provide certain meteorological and operational data to public utility transmission providers with whom they are interconnected, to facilitate the development and deployment of power production forecasting for VERs.[18]

The IRC agrees with the Commission that "increased use of power production forecasts in transmission systems where VERs are located can provide transmission providers with improved situational awareness, enable transmission providers to utilize existing system flexibility through the unit commitment and dispatch processes, and, ultimately lead to a reduction in the amount of reserve products needed to maintain system reliability."[19] In fact, as both the IRC White Paper[20] and NOPR[21] discussed, RTOs and ISOs have either already instituted or are investigating the deployment of a series of power production forecasting tools. As more VERs are interconnected, sophisticated power production forecasting tools will play an important role in enabling

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17 NOPR at P 56.

18 NOPR at P 60. Specifically, the Commission's proposal would require wind generators to provide data relating to temperature, wind speed, wind direction, and atmospheric pressure. *Id.* at P 61. Solar-based VERs would be required to report temperature, atmospheric pressure, and cloud cover data. *Id.* All VERs would be required to report forced outages that reduce generating capacity by 1 MW or more for 15 minutes or more. *Id.* at P 62.

19 NOPR at P 55.

20 IRC White Paper at 12-18.

21 NOPR at PP 47-48.

RTOs and other transmission providers to maintain reliability and balancing of the system.

The IRC supports the Commission's proposal to respect regional differences and refrain from mandating the development of power production forecasting, given the differing levels of VER presence in different parts of the country.[22] However, the IRC is concerned that non-uniform adoption of power production forecasting (as well as the resultant requirement on VERs to provide such information) could result in unintended consequences. Accordingly, the IRC recommends that the Commission consider requiring transmission providers in regions with significant VER penetration to adopt power production forecasting tools and data requirements for VERs in such regions. While transmission providers in areas with low to moderate levels of VER interconnection may be able to manage variability on their systems without using such tools, areas with larger levels of VERs should be required to adopt power production forecasting tools to ensure that conditions affecting generation output can be anticipated and managed appropriately.

Non-uniform adoption of production forecasting in areas with vast of levels VER penetration could affect reliability. Specifically, failure of a transmission provider to adopt power production forecasting tools could impact not only the transmission provider's system but interconnected neighboring systems through parallel flows, even if the neighboring transmission provider has diligently deployed power production forecasting tools for VERs interconnected to their systems. A voluntary approach could affect the ability of adjacent systems to engage in effective seams coordination where one

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[22] NOPR at P 56.

system has adopted power production forecasting and the other has not. Additionally, one transmission provider's adoption of forecasting tools and data requirements could affect the siting decisions of VER interconnection customers seeking to avoid the obligation to provide such data. Thus, while the IRC supports the Commission's proposal not to enact a nationwide mandate for power production forecasting, the IRC cautions the Commission to consider the impact of uneven adoption of power production forecasting, particularly in areas with rich VER potential.

The IRC also is concerned about the Commission's proposal not to require VERs with LGIAs that are already in effect to comply with the same disclosure requirements.[23] Transmission providers that implement forecasting tools should have the flexibility to collect data from all VERs, including VERs operating under currently effective LGIAs. As discussed above, power production forecasting can be valuable in enabling transmission providers to anticipate and react to unexpected changes in system conditions and to reduce reliance on reserves. Allowing transmission providers to collect this information only from a subset of VER interconnection customers (*i.e.*, those that have not yet executed the LGIA) will hamper transmission provider efforts to collect the full set of data necessary to implement effective power production forecasting. While still useful, power production forecasting based on data from only a portion of the VERs on the system will paint an incomplete picture of system conditions and will prevent transmission providers from realizing the full benefit of power production forecasting.

[23] NOPR at P 64.

Moreover, as the NOPR recognizes, VERs continue to make up a growing percentage of new generating capacity coming online.[24] Certain regions have at this time installed significant VER capacity, and allowing such regions to collect meteorological and operating data from existing VERs would facilitate more accurate power production forecasting and maximize the benefits that forecasting tools provide. Transmission providers that have implemented power production forecasting tools should be afforded the flexibility to adopt mechanisms to collect necessary meteorological and operational data from all VERs, whether those VERs are already in service or are still in the interconnection process.[25]

In addition, the Commission should allow transmission providers flexibility to require additional information from VER interconnection customers beyond the meteorological and operational data identified in the NOPR. For example, in addition to raw data, it may be useful for VERs to provide information to the transmission provider addressing what actions the VER operator plans to take to address forced outages and other unanticipated issues. Transmission providers should be provided flexibility to determine what other data should be required from VER interconnection customers to implement effective power production forecasting.

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24 NOPR at P 13.

25 The NOPR appears to suggest that existing LGIAs must be modified to require existing interconnection customers to provide meteorological and operational data. *See, e.g.*, NOPR at P 64 ("[T]he Commission proposes not to require retroactive changes to large generator interconnection agreements that are already in effect."). The final rule in this proceeding should clarify that transmission providers may adopt such data requirements either through modification of LGIAs, through Tariff revisions, or through other business practice or protocol changes that apply to interconnection customers, as appropriate.

Finally, the IRC is concerned that the proposed compliance deadline of six months will not provide sufficient time for transmission providers to implement VER power production forecasting tools and develop any necessary modifications to their tariffs, LGIAs, or other documents through their stakeholder process. Specifically, transmission providers will require time to negotiate with VER interconnection customers details regarding the meteorological and operational data required by their LGIA,[26] and, to the extent that the Commission permits transmission providers to apply meteorological and operational data requirements to existing interconnection customers,[27] transmission providers will need even more time to negotiate such requirements with interconnection customers and other stakeholders. Therefore, the Commission should extend the compliance deadline for power production forecasting to one year from the effective date of the final rule.

C. Generator Regulation Service

The NOPR proposed requiring all public utility transmission providers to offer generator regulation service to all transmission customers, and to modify the *pro forma* OATT to incorporate a generic Schedule 10—Generator Regulation and Frequency Response Service, modeled after existing Schedule 3—Regulation and Frequency Response Service.[28] Under the proposal, transmission providers would be required to offer generator regulation service to the extent that it is physically feasible to do so from

[26] *See* NOPR at P 61 ("[T]he Commission will refrain from proposing specific requirements [for meteorological and operational data], and instead proposes to allow the public utility transmission provider and interconnection customer to negotiate these details.").

[27] *See supra* note 26 and accompanying text..

[28] NOPR at PP 85, 88.

its resources or resources available to it.[29] The Schedule 10 rate would permit transmission providers to recover the costs associated with holding capacity sufficient to provide the service, and would be a complementary service to current Schedule 9—Generator Imbalance Service.[30] The transmission customer would be required either to purchase Schedule 10 service or demonstrate that it has satisfied its regulation service obligation through dynamically scheduling its generation to another balancing authority or by self-supplying regulation reserve capacity from generation or non-generation resources.[31] The proposed Schedule 10 charge would be the product of a per-unit rate for regulation reserve capacity and a volumetric component for regulation reserve capacity.[32]

The IRC supports the Commission's recognition that VERs present challenges to the ability of transmission providers to balance their systems and respond to generation resource variability, particularly VER variability, and that transmission providers should have a mechanism through which to recover the costs associated with providing regulation and frequency response services to generation resources. The IRC also supports the Commission's proposal to allow transmission providers to propose the appropriate volumetric component of the Schedule 10 charge in their compliance filings[33]

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29 NOPR at P 89.

30 NOPR at P 87.

31 NOPR at P 89.

32 NOPR at P 92.

33 NOPR at P 94 ("Instead, we preliminarily find that each public utility transmission provider should propose a method of apportioning such volumes of generation reserves, based on the facts and circumstances of its individual system.").

and to determine whether to implement different volumetric requirements for different types of generation resources.[34]

D. Compliance Filing

In the event that the Commission does not agree with the IRC's comments above and adopts the NOPR proposal to require a 15-minute scheduling option, the IRC submits that six months does not provide sufficient time for transmission providers to develop the necessary revisions, inter-regional agreements and procedures, and system modifications to implement the VER integration requirements of the final rule.[35] Adoption of the NOPR proposal to mandate a 15-minute scheduling option for transmission customers would result in a significant paradigm shift from the current state of affairs in the industry, which, as discussed above, would carry significant implementation costs and challenges for both small systems and larger, more developed markets to which such systems interconnect. Requiring full compliance with the final rule within six months of its effective date will put a significant strain on the resources of transmission providers and stakeholders, with no concurrent benefit. Therefore, in the event that the Commission adopts the NOPR proposal, the IRC respectfully requests that the Commission allow transmission providers at least one year for the submission of compliance filings with the ability of transmission providers to make individual filings justifying a later compliance date if they cannot meet that compliance deadline.

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[34] NOPR at P 95 ("[A] public utility transmission provider may require a transmission customer delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserve to the extent that the different regulation reserve volumes are supported by data showing that… VERs impose a different per unit impact....").

[35] NOPR at P 101.

III. CONCLUSION

For the foregoing reasons, the IRC supports the Commission's desire to facilitate VER integration but opposes any national mandate that does not account for regional differences in VER potential, system capability, and market design. The Commission should modify its NOPR proposal as discussed above, and allow transmission providers no less than one year to implement reforms and submit the necessary compliance filings.

Respectfully submitted,

/s/ Anthony Ivancovich
Anthony Ivancovich
Assistant General Counsel-Regulatory
California Independent System Operator Corporation
151 Blue Ravine Road
Folsom, California 95630

/s/ Raymond W. Hepper
Raymond W. Hepper
Vice President, General Counsel, and Secretary
Theodore J. Paradise
Senior Regulatory Counsel
ISO New England, Inc.
One Sullivan Road
Holyoke, Massachusetts 01040

/s/ Stephen G. Kozey
Stephen G. Kozey
Vice President, General Counsel, and Secretary
Midwest Independent Transmission System Operator, Inc.
P.O. Box 4202
Carmel, Indiana 46082-4202

/s/ Carl F. Patka
Carl F. Patka
Assistant General Counsel
New York Independent System Operator, Inc.
10 Krey Blvd
Rensselaer, New York 12144

/s/ Craig Glazer
Craig Glazer
Vice President – Federal Government Policy
Robert Eckenrod
Counsel
PJM Interconnection, LLC
1200 G Street, N.W. Suite 600
Washington, D.C. 20005

/s/ Heather H. Starnes
Heather H. Starnes, J.D.
Manager – Regulatory Policy
Southwest Power Pool
415 North McKinley, #140 Plaza West
Little Rock, Arkansas 72205

/s/ Brian Rivard
Brian Rivard
Manager – Regulatory Affairs & Sector Policy Analysis
Ontario's Independent Electricity System Operator
655 Bay Street, Suite 410
Toronto, Ontario M5G 2K4

/s/ Matthew Morais
Matthew Morais
Assistant General Counsel
Electric Reliability Council of Texas
7620 Metro Center Drive
Austin, Texas 78744

/s/ Kevin Roherty
Kevin Roherty
Secretary and General Counsel
New Brunswick System Operator
510-C Brookside Drive
Fredericton, NB E3A 8V2

/s/ Diana D. Pommen
Diana D. Pommen
Director Interjurisdictional Affairs and Compliance
Alberta Electric System Operator
2500, 330 – 5 Avenue SW
Calgary, Alberta T2P 0L4

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