UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE ORGANIZATION OF MISO STATES

I. Introduction

The Organization of MISO States (OMS) submits these comments in response to the Federal Energy Regulatory Commission (Commission) Notice of Proposed Rulemaking (NOPR) issued in the above-captioned docket on November 18, 2010, and the Notice issued December 16, 2010[1] extending the comment period to March 2, 2011.

In the NOPR, the Commission proposes to amend the pro forma OATT to remove unduly discriminatory practices and to ensure just and reasonable rates for Commission-jurisdictional services to remove barriers to the integration of Variable Energy Resources (VERs).

The Proposed Rule would:

(1) require public utility transmission providers to offer intra-hourly transmission scheduling;

(2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of power production forecasting; and

(3) add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service, through which public utility transmission providers will

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[1] *Integration of Variable Energy Resources,* 133 FERC ¶ 61,149 (2010).

offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area.[2]

The OMS supports the utilization of intra-hourly transmission scheduling and meteorological and operating data to improve integration of VERs into the system and reduce overall ancillary service (generator imbalance) costs. The Commission should use these means provided for in this NOPR to minimize the need for and therefore the costs associated with variable energy integration. The OMS also supports the addition of Schedule 10 – Generator Regulation and Frequency Response Service to the pro forma OATT and the allocation of associated costs based on the Commission's cost causation principle.[3] The OMS also supports a clear showing of costs associated with regulation reserves and VER integration in a Section 205 filing prior to granting cost recovery and allocation to transmission providers.

II. Background

In Order 888, the Commission believed it was reasonable to provide standardized regulation and energy imbalance schedules for transmission service used to serve load because load (rather than generation) exhibited the greatest amount of variability. The Commission also noted that generators should be able to deliver scheduled hourly energy with precision and that the requirements for generators to meet their schedules should be contained in interconnection agreements.[4] The Commission therefore created Schedule 3 – Regulation Service and Schedule 4 – Energy Imbalance charges for load in the *pro forma* OATT.

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[2] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 3.
[3] Montana suggests that FERC incorporate provisions in its final order to include Small Generator Interconnection Agreements down to 1MW for Schedule 10 and intra-hour scheduling.
[4] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 66 – 69.

In Order No. 890, the Commission made several reforms to the *pro forma* OATT, recognizing that the mix of generation resources on the system was changing and that not all generation resources were similarly situated. The Commission recognized that intermittent resources, such as wind power,[5] have a limited ability to control their output, and that this limitation supports tailoring certain requirements to the special circumstances presented by this type of resource.[6] These concerns led the Commission to revise the *pro forma* OATT's existing Energy Imbalance Service provisions to include a requirement for transmission providers to offer Generator Imbalance Service. This service would allow transmission providers to account for hourly energy deviations between scheduled energy delivery from a generator and the actual amount of energy injected by that generator.[7]

The addition of Generator Imbalance Service resulted in a formalized mechanism for the recovery of costs associated with providing energy needed to manage imbalances between a generator's scheduled and delivered energy. However, the addition of the Generator Imbalance Service did not provide a formal mechanism for transmission providers to recover the costs of holding increasing quantities of regulation to address a growing quantity of energy imbalances caused by increased variability from generators. At that time, the Commission acknowledged the need for additional regulation reserves associated with energy imbalances from generators, but did not go as far as to revise the *pro forma* OATT to formalize the service. Instead the

[5] While the NOPR definition of VERS "includes wind, solar, thermal and photovoltaic, and hydrokinetic generating facilities," wind generation is becoming the significant VER in the Midwest. NOPR at footnote 2.
[6] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 2.
[7] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 70.

Commission required any transmission provider who desired to recover those additional regulation costs caused by generators to do so through a separate section 205 filing.[8]

In the VER Notice of Inquiry (NOI), the Commission asked for comment on whether the variability associated with the increased number of VERs caused a need to procure additional reserves, i.e. regulation.[9] Comments from certain VER supporters[10] did not deny that VERs caused increased variability or increased need for regulation reserve, but instead focused on the fact that current industry operational practices were not designed to accommodate VERs. Therefore, such supporters of VERs asserted that the costs of holding extra regulation reserves to accommodate VERs should not be assessed to VERs, and instead the transmission provider should adapt its operational practices to incorporate VERs in a manner that eliminates or significantly minimizes the need to hold additional regulation reserves to integrate VERs.[11] Others, including transmission providers,[12] express that it is necessary to recover the increased cost of regulation reserves and recognize the cause of such added reserves to be VER integration.

In the VER NOPR, among other things, the Commission seeks to bring consistency to the manner by which transmission providers recover the cost of providing the additional regulation reserve caused by generators unable to provide in operation the precise amount of energy scheduled. The Commission takes the first step in reducing the uncertainty associated with the allocation of increased regulation costs associated with VERs by proposing Schedule 10 – Generator Regulation and Frequency Response Service as a revision to the *pro forma* OATT.

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[8] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 71.
[9] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 75.
[10] VER supporters include national wind advocate, AWEA, and wind developers NextERA and Iberdrola.
[11] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 76.
[12] Others include Xcel, Bonneville, and Westar.

III. Comments

A. Requirement of Intra-Hourly Transmission Scheduling

The OMS supports the Commission's proposal to require public utility transmission providers to offer intra-hourly transmission scheduling.[13] Specifically, the Commission proposes:

> To require public utility transmission providers to offer all transmission customers the option to submit changes to schedules in an interval of 15 minutes and allow all transmission customers the option of submitting intra-hour schedules up to 15 minutes before the scheduling interval. While the Commission proposes to establish a 15-minute scheduling interval, this proposed reform is not intended to deter public utility transmission providers from providing transmission scheduling intervals that are less than the proposed 15-minute period. To the extent public utility transmission providers incur costs as a result of implementing this proposed scheduling reform; the Commission proposes to allow such costs to be recovered pursuant to Schedule 1 of the transmission providers' OATTs.[14]

The Commission notes that it expects this proposed reform to benefit many types of entities. Shorter schedule intervals should provide public utility transmission providers greater assurance that the schedules submitted by transmission customers using VERs are accurate. Therefore, public utility transmission providers will be in a better position to anticipate and respond to fluctuations in VER energy production. In this way, the public utility transmission provider will be able to rely more on planned scheduling and dispatch procedures in maintaining overall system balance and rely less on reserves. The Commission notes that transmission customers delivering energy from VERs will be in a reasonable position to match their scheduled output with actual output, thereby better managing their exposure to generator imbalance charges. Likewise, transmission customers delivering energy from energy constrained resources,

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[13] Montana believes that the FERC should implement 30 minute scheduling in non-organized markets, to remain consistent with the efforts of the Western Interconnection Joint Initiative.
[14] FERC NOPR for VERs at 41.

such as flow-limited hydro generators, emission-limited thermal generators, demand response resources and energy storage resources will be better able to schedule transmission to reflect constraints in their operations. The Commission concludes that scheduling flexibility should help balancing authorities to closely match scheduled production with actual output, which will enhance ability to meet NERC Reliability Standards.[15]

The OMS agrees with the Commission's overall recommendations and proposal to offer intra-hourly transmission schedule. The OMS also would like to see a clear showing of costs incurred to implement this proposed schedule reform, in light of some parties in this proceeding indicating there may not be costs or the costs may be limited, prior to the Commission allowing recovery pursuant to Schedule 1 of the transmission providers' OATT.

B. Require VERs to Provide Meteorological and Operational Data

The OMS generally supports the Commission's proposal to require VERs that are 20 megawatts or larger to provide Meteorological and Operational Data in Large Generator Interconnection Agreements (LGIA).[16] Specifically, the Commission proposes the following for Meteorological Data:

> The Commission proposes revisions to the LGIA that will result in different types of meteorological information being provided by interconnection customers based on the type of VER they own and/or operate. In order to enable the most accurate power production forecasts, the proposed revision to the LGIA would require that such data be transmitted from the interconnection customer to the public utility transmission provider at or near real-time. The Commission proposes to revise the *pro forma* LGIA to require interconnection customers with wind-based VERs to provide public utility transmission providers with site specific meteorological data including, but not limited to: temperature, wind speed, wind direction, and atmospheric pressure. The Commission proposes to revise the *pro forma* LGIA to require interconnection customers with solar based VERs to provide public utility transmission providers with site specific meteorological data

[15] FERC NOPR for VERs at 40.
[16] Montana argues that the Commission should require all VER's above 1 MW to provide Meteorological and operational data. Montana does not support FERC requiring the transmission provider to provide a power production forecast for the VER.

> including, but not limited to: temperature, atmospheric pressure, and cloud cover. The Commission recognizes that different forecasts may require meteorological instruments to be located at hub height, up-wind of resources, or at ground level. However, the Commission will refrain from proposing specific requirements in this respect, and instead proposes to allow the public utility transmission provider and interconnection customer to negotiate these details taking into account the size and configuration of the VER facility, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. The resource-specific data requirements contained in individual LGIAs must be negotiated on a not unduly discriminatory basis.[17]

Specifically, the Commission proposes the following for Operational Data:

> With respect to operational data, the Commission proposes to revise the *pro forma* LGIA to require interconnection customers whose generating facilities are VERs to report to the public utility transmission provider any forced outages that reduce the generating capability of the resource by 1 MW or more for 15 minutes or more. This proposal is similar to a recent CAISO proposal accepted by the Commission on April 30, 2010. As indicated in that case, the requirement to report outages down to a 1 MW threshold will improve power production forecasting accuracy. Provision of VER outage data to this level of granularity will allow a public utility transmission provider to ascertain the extent to which VER current power production is a result of unit availability as opposed to changing weather conditions. If a VER is composed of a number of individual generating units, it is important for the public utility transmission provider to know how many individual generating units are capable of producing energy at any given time. Having such information will eliminate a significant source of forecasting error by ensuring that the public utility transmission provider has accurate information regarding the capacity actually available to produce electricity during the time frame of the operational forecasts.[18]

Since better Meteorological and Operational data will improve the integration of VERs into the transmission system and should result in overall more efficient use of the electric grid including reducing ancillary service costs overall, without getting into the specific details, the OMS generally supports the Commission's proposal to require VERs to provide Meteorological and Operational Data in Large Generator Interconnection Agreements (LGIA).

[17] FERC NOPR for VERs at 61.
[18] FERC NOPR for VERs at 62 (footnotes omitted).

C. Add Schedule 10 – Generator Regulation and Frequency Response Service

The OMS generally supports the Commission's proposal to add Schedule 10 – Generator Regulation and Frequency Response Service. Specifically, the Commission proposes the following for Schedule 10 – Generator Regulation and Frequency Response Service

> The Commission proposes to add a new rate schedule to the pro forma OATT that complements the generator imbalance service provided under Schedule 9 of the pro forma OATT. In order to meet their obligations to offer generator imbalance service under Schedule 9, public utility transmission providers must hold unloaded resources in reserve to respond to moment-to-moment variations attributable to generation. The proposed reform recognizes this de facto obligation and establishes a generic rate schedule (Schedule 10—Generator Regulation and Frequency Response Service) through which public utility transmission providers may recover the costs of providing this service. The Commission preliminarily finds that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer this service will remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.
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> The Commission notes that the proposed Schedule 10 is modeled on Schedule 3—Regulation and Frequency Response Service of the pro forma OATT. Where Schedule 3 allows public utility transmission providers to recover the costs of regulation reserves associated with variability of load within its balancing authority area, proposed Schedule 10 will provide a mechanism through which public utility transmission providers can recover the costs of providing regulation reserves associated with the variability of generation resources both when they are serving load within the transmission provider's balancing authority area and when they are exporting to load in other balancing authority areas.
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> The Commission notes that under proposed Schedule 10, a public utility transmission provider must offer generator regulation service, to the extent it is physically feasible to do so from its resources or from resources available to it, to transmission customers using transmission service to deliver energy from a generator located within the transmission provider's balancing authority area. A transmission customer subject to Schedule 10 must either take service pursuant to this proposed rate schedule or demonstrate that it has satisfied its regulation service obligation through dynamically scheduling its generation to another balancing authority area or by self-supplying regulation reserve capacity from generation or non-generation resources. Furthermore, consistent with Order No. 890, public utility transmission providers may not charge transmission customers for

regulation reserves under both Schedule 3 and proposed Schedule 10 for the same transaction.[19]

The OMS supports the Commission's proposal to add Schedule 10 – Generator Regulation and Frequency Response Service. The OMS also supports allocating the cost associated with any increased regulation reserves needs associated with generator variability to be assigned to those that caused the cost.[20, 21]

D. Schedule 10 Cost Causation

The Commission clearly states that the new Schedule 10 will be used to set a rate for the Generator Regulation and Frequency Response, but does not require any volume of regulation service to be recovered under this rate.[22] Previously, through Order 890, the Commission adopted a case-by-case approach to setting rates and volumes for transmission providers to recover the costs of regulation reserves caused by generation variability. In this NOPR, the Commission is attempting to bring some consistency to the manner in which transmission providers charge generators for regulation service.

The Commission does not appear to actually require transmission providers to recover the costs associated with any of the volume of regulation reserves held because of any increased system variability caused by VER integration from any generators, let alone from the generators exhibiting the variability. The Commission explicitly recognizes the transmission provider's

[19] FERC NOPR for VERs at 87-89 (footnotes omitted).

[20] Minnesota and Iowa note that since the benefits of low cost energy from wind are shared across RTO's footprint, operational improvements such as intra-hour scheduling and improved meteorological and operating data should be pursued first, prior to trying to assign ancillary costs which have yet to be clearly defined in a Section 205 rate recovery filing.

[21] Montana feels that FERC should allow a transmission provider to recover the costs of providing regulation and frequency response services from new and existing VERs before the transmission provider has made the changes to provide intra-hour scheduling and meteorological and operational data.

[22] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 85.

need to hold regulating reserves to meets its obligation to provide generator imbalance service in the following statement:

> In order to meet their obligations to offer generator imbalance service under Schedule 9, public utility transmission providers must hold unloaded resources in reserve to respond to the moment-to-moment variations attributable to generation.[23]

In subsequent statements it becomes unclear as to whether or not the Commission is going to require that the generators causing costs pay the rate for any volume greater than zero. Specifically, statements like the following make it sound as if the Commission will not require transmission providers to charge any generators for regulation service.

> The proposed reform recognizes this de facto obligation and establishes a generic rate schedule (Schedule 10 – Generator Regulation and Frequency Response Service) through which public utility transmission providers **may** recover the costs of providing the service.[24] The Commission preliminarily finds that clarifying the manner by which public utility transmission providers **may** recover the costs associated with fulfilling their obligation to offer this service will remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.

These statements appear to imply that a transmission provider does not need to recognize the cost causation principle in recovering the cost of additional regulating reserves caused by VERs, but that the transmission provider may recognize the cost causation principle. These statements conflict with the Commission's assertions that it supports the adherence to cost causation principles. Subsequently, the Commission makes the statement that…

> Under proposed Schedule 10, a public utility transmission provider **must** offer generator regulation service, to the extent it is physically feasible to do so from its resources or from resources available to it, to transmission customers using

[23] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 87.
[24] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 87 (emphasis added).

> transmission service to deliver energy from a generator located within the transmission provider's balancing authority area.[25]

However, this statement is not equivalent to requiring generators to pay the Schedule 10 rate for the volume of regulation service they cause the transmission provider to procure on their behalf. The Commission's proposal is that the transmission provider must have a rate schedule which allows generators to purchase regulation service from the transmission provider (to the extent the transmission providers is physically feasible to do so), but does not require the transmission provider to require that generators purchase the service. The OMS believes the Commission should require the allocation of the regulating reserve cost to generators when the variability in generation output causes the need to hold those additional regulating reserves in order to ensure just and reasonable rates.[26]

E. Schedule 10 Rates and Volumes

The regulation reserve capacity requirement for generation is the per-unit cost and associated volume of unloaded generation or other non-generation resources held in reserve to manage the variability in a reliable manner.[27] The Schedule 10 charge used to recover the regulation reserve capacity requirement cost will be the product of two components, the per-unit rate for regulation and volume of regulation allocated to generators for the variability they cause on the system. The Commission finds it just and reasonable in the NOPR to charge the same per-unit rate under Schedule 10 as it does under Schedule 3 because the service provided under both is functionally equivalent. If the transmission provider wishes to charge a different rate

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[25] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 89 (emphasis added).

[26] Minnesota and Iowa note that the Lawrence Berkley National Laboratory released a study in December 2010 entitled "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation" which suggests that wind has only a minor impact on variability of frequency.

[27] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 92.

under Schedule 10, then the transmission provider would have to show that the per-unit cost of the regulation reserve capacity is somehow different when the capacity is utilized to address variability associated with generator variability.[28]

The notion that a different rate might need to be charged for regulation associated with generation versus load or one generation resource versus another potentially distracts from a more relevant issue, allocation of volumes. Variability and the need to procure reserves to reliably protect against the sudden imbalances created do not seem to change the nature of the service. As the Commission recognized, regulation for load or generation is functionally equivalent. Each MW of regulation would reliably protect against the same magnitude of variability whether it is caused by generation or load and the same for one generation resource versus another. The more relevant concern should be volumetric. Each MW of load will display a different variability than a MW of generation, and each MW of generation from one resource will display a different amount of variability than will a MW of generation from another type of resource. This would result in the need to hold a different number of MW of regulation reserve (volume) for load and different types of generation, and not charge a different rate for each MW.

The Commission recognized that variability may be different among different generation resources, [29] and many commenters indicate that VERs may impose a disproportionate impact on system variability thereby causing the transmission provider to hold a greater per MW amount of regulation reserves for VERs than load and/or other generation sources.[30] The Commission asserts that it agrees that the cost of regulation reserves should be allocated according to the cost

[28] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 93.
[29] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 94.
[30] See footnote 26.

causation principle, but does not mandate a particular method for apportioning the volume of regulation to different generation types, nor does it require transmission providers to propose any differential volumetric appropriation.[31] The Commission allows transmission providers to allocate different volumes to transmission customers, including VERs, only if the transmission provider provides data that show certain transmission customers including VERs impose a different impact on system variability.

F. Schedule 10 Should be Targeted to Cost Causers[32]

Although the addition of Schedule 10 is premised on the notion that the integration of VERs causes volatility on the system that is not caused by traditional forms of generation, the Commission does not require the costs of increased regulation and frequency response to be allocated to VERs in a manner that is consistent with the cost causation principle. The Commission provides a rate schedule for generation resources generally, but leaves the application of that schedule to the discretion of the transmission provider. This discretion provides the transmission providers with an opportunity for undue discrimination because traditional generation resources operate with precision, but are potentially subject to increased cost associated with the variability created by VER. Furthermore, any variability that is created by VERs, but is not allocated to VERs or other generation resources, will result in undue discrimination against load that has not caused the additional need for regulation service.

Under the default mechanism provided in the NOPR, the increased regulation cost would likely be assigned to load.[33] The existence of the Schedule 10 rate does not appear to require the

[31] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 94.

[32] Minnesota and Iowa do not support section F in its entirety, since from our perspective these comments are too strong, make assumptions that we do not agree with, and are not supported with citations from the NOPR

transmission provider to allocate any costs of increased regulation to any generation. It appears that the new Schedule 10 only provides a rate which can be applied to all generators, no generators or those generators who have caused the need for increased quantities of regulation service. However, the Commission has provided several hurdles for transmission providers to allocate those costs where they are due.

First, the transmission provider must make a section 205 filing if it desires to assign a disproportionate amount of regulation to a specific generation type, *e.g.* VERs.[34] There is no requirement for the transmission provider to do so however, even though the premise of the NOPR is that these resources are the cause of the increased cost. The Commission would be prudent and provide just and reasonable rates only if it were to require transmission providers to analyze the impacts on regulation service caused by the increased number of VERs and allocate cost accordingly. Second, the Commission makes a requirement for transmission providers to make changes to operational practice and develop new forecasting processes as a result of the variability caused by increased VER integration.[35] These costs will likely be born by all market participants although they too are directly caused by the operational inefficiencies of VERs.

G. Example of VER Variability[36]

Strings of wind output data from the Midwest ISO can be used to examine the system volatility created by the most prominent VER in the Midwest ISO.[37] 8,747 MW of the total

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[33] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 85.
[34] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 95.
[35] Notice of Proposed Rulemaking on Integration of Variable Energy Resources, Docket RM10-11-000, November 18, 2010 at 97.
[36] Minnesota and Iowa do not support section G in its entirety, since from our perspective these comments are too strong, make assumptions that we do not agree with, and are not supported with citations from the NOPR.
[37] Summary reports including Historic Hourly Wind Data are publically available at the Midwest ISO Market Reports website https://www.midwestiso.org/Library/MarketReports/Pages/MarketReports.aspx.

145,966 MW of registered market capacity, or 6% of total capacity in the Midwest ISO, is wind capacity.[38] On February 8, 2011, the Midwest ISO posted to its website hourly wind output data for hour ending 0:00 January 1, 2011 to hour ending 0:00 February 8, 2011. The total number of data points in this data set is 913. The average hourly wind output for this data set is 2,935 MWh. The standard deviation or average difference from that average of 2,935 MWh is 1726 MWh. Also, the average hourly change in wind output is equal to 201 MWh.[39] This means that on average the total output from aggregate Midwest ISO wind generation changes by 201 MWh each hour. Therefore, in an average hour output is 2,935 MWh and the next hour's output will be plus or minus 201 MWh, 3,136 or 2,734 MWh. This average change after the average hour represents a 6.8% change. This represents a significant change in output in the average hour which needs to be covered by holding additional regulation reserves. The cost of holding these additional regulating reserves should be allocated to the wind generators which cause the need to hold the additional reserves in order to satisfy the Commission's cost causation principle. Adhering to this cost causation principle should not only be required for wind generators, but for other VERs which display their own level of quantifiable variation.

IV. Recommendations

A. Requirement of Intra-Hourly Transmission Scheduling

The OMS agrees with the Commission's overall recommendations and proposal to offer intra-hourly transmission schedule. The OMS would like to see a clear showing of costs incurred to implement this proposed schedule reform, in light of some parties in this proceeding

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[38] Midwest ISO Corporate Fact Sheet located at https://www.midwestiso.org/AboutUs/MediaCenter/pages/MediaCenter.aspx

[39] Hourly changes are simply the difference between the hourly output in one hour and the hourly output in the hour directly following it. The absolute value of these hours is then taken to avoid netting increases in output from decreases in output. These numbers are summed and divided by the total number of changes calculated to the average hourly change in wind output.

indicating there may not be costs or the costs may be limited, prior to the Commission allowing recovery pursuant to Schedule 1 of the transmission providers' OATT.

B. Require VERs to Provide Meteorological and Operational Data

Since better Meteorological and Operational data will improve the integration of VERs into the transmission system and should result in overall efficient use of the electric grid including reducing ancillary service costs overall, without getting it the specific requirements, the OMS generally supports the Commission's proposal to require VERs to provide Meteorological and Operational Data in Large Generator Interconnection Agreements (LGIA).

C. Add Schedule 10 – Generator Regulation and Frequency Response Service

The OMS supports the Commission's proposal to add Schedule 10 – Generator Regulation and Frequency Response Service that would require public utility transmission providers to provide generator regulation service, to the extent it is physically feasible to do so, and allow transmission providers to support needed recovery of costs.

D. Allocate the Procurement Cost of Rate Schedule 10 to Cost Causers

In order to ensure that rates are just, reasonable, and not unduly discriminatory, the Commission should require that transmission providers with significant VER capacity, such as 3% or more of total capacity, submit statistical data on the variability of generation across the different types of generation resources and load. If there is a significant difference between the different types of resources, then transmission providers should be required to allocate the costs of increased regulation or other ancillary services developed in the future needed to accommodate that variability. The measure of variability could be the average of the absolute value of the deviations from scheduled output. In the instance that some resources, i.e. VERs, are not required to comport to a given schedule, then other measures of variability could be utilized. For instance, the standard deviation of VER output could serve as a measure of variability. The same measure may not be appropriate for other forms of generation as other generation resources are often required to change their output. Regardless of the actual calculation, transmission providers with significant VER capacity (OMS suggests greater than or equal to 3% of total capacity) should be required to submit data supporting a disproportionate appropriation of regulation reserve costs to those generation resources that cause those costs in order to ensure that rates are just reasonable and not unduly discriminatory.

V. CONCLUSION

The OMS appreciates this opportunity to provide comments.

The OMS submits these comments because a majority of the members have agreed to generally support them. Individual OMS members reserve the right to file separate comments regarding the issues discussed in these comments. The following members generally support those comments:

Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Missouri Public Service Commission
Montana Public Service Commission
North Dakota Public Service Commission
South Dakota Public Utilities Commission
Wisconsin Public Service Commission

The Manitoba Public Utilities Board, the Public Utilities Commission of Ohio, and the Pennsylvania Public Utility Commission did not participate in this pleading.

The Indiana Office of Utility Consumer Counselor, the Iowa Office of as Consumer Advocate, and the Minnesota Office of Energy Security, as associate members of the OMS, participated in these comments and generally support these comments.

Respectfully Submitted,

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