UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE RENEWELEC PROJECT ON INTEGRATION OF VARIABLE ENERGY RESOURCES NOTICE OF PROPOSED RULEMAKING

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I. ABOUT THE RENEWELEC PROJECT

A significantly expanded role for variable energy resources (VERs) is technically possible. But, large scale integration of VERs can be achieved only if the U.S. adopts a systems approach that considers and anticipates the many changes in power system design and operation that will be required to make this possible, while doing so at an affordable price, and with acceptable levels of security and reliability. The RenewElec Project was created as an interdisciplinary project led by Carnegie Mellon University to facilitate dramatic increases in the use of electric generation from variable and intermittent sources of renewable power in a way that:

- Is cost-effective;
- Provides reliable electricity supply with a socially acceptable level of local or large-scale outages;
- Allows a smooth transition in the architecture and operation of the present power system;
- Allows and supports competitive markets with equitable rate structures;
- Is environmentally benign; and
- Is socially equitable.

The RenewElec Project, through an applied research approach that examines the building block system engineering and economics issues raised by VER integration, will provide policymakers with actionable, relevant data to inform decision-making. This interdisciplinary collaboration will build on the expertise of Carnegie Mellon's Electricity Industry Center and other research in the Department of Engineering and Public Policy, the Tepper School of Business and the Department of Electrical and Computer Engineering, as well as colleagues at other institutions. Prior to publishing a comprehensive monograph in 2013, the Project is commissioning and producing white papers and policy briefs on a variety of topics. Topics already explored in RenewElec's research include:

- The economically efficient capacity of a transmission line fed by variable or intermittent generation;
- The use of the fundamental frequency-domain character of wind power generation and high time-resolution power output data from wind farms to determine the amount of actual wind plant-by-wind plant smoothing of wind variability;
- The actual full-system reduction in CO_2 and NO_x emissions from combined wind and natural gas generation;
- The cost-effective amount of fast-ramping battery storage that can be paired with wind to decrease variability mitigation costs;
- The cost of mitigating wind power variability for 20 wind farms in Texas, using measured wind output data and ancillary service prices over several years.

These and other work products the RenewElec Project will produce over the next three years are intended to inform and assist federal, state, non-governmental and corporate decision-making groups, as well as to provide clear and understandable explanations to members of the general public. The Project will be informed through feedback obtained in formal and informal briefings and via the projects web site.

II. COMMUNICATIONS

All materials and communications relating to these proceedings should be served on the following:

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III. OVERVIEW OF COMMENTS

RenewElec commends the Federal Energy Regulatory Commission (Commission) for undertaking a measured approach in proposing "those basic reforms that can and should be implemented in the near term" to address the most obvious barriers to successfully integrating variable energy resources into the interstate transmission system in a coherent, cost-effective and non-discriminatory manner.[1] The Notice of Proposed Rulemaking (NOPR) properly recognizes that successful integration will depend in large part on the development of robust forecasting tools and methodologies, and that such technologies and methodologies are still in various stages of development.

The basic conundrum at this point in the integration of those renewable resource electric generation facilities producing energy on a variable/weather related basis (VERs)[2] is how to refine the type of data to be provided by generators for forecasting methodologies still undergoing substantial development, and then relate the forecasting results to the risks faced by transmission providers and balancing authorities in the minute-to-minute operations of their systems. RenewElec's comments express support for the Commission's proposal to require public utility transmission providers to implement intra-hour scheduling, but urge the

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[1] *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, 75 Fed. Reg. 75,336 (December 2, 2010), FERC Stats. & Regs. ¶ 32,664 at P 18 (2010) (VER NOPR).

[2] The term "VER" is not synonymous with generation based on renewable resources. Generation using biomass, geothermal and hydroelectricity using water as renewable fuels are dispatchable and are not VERs.

Commission to require five minute scheduling in areas with significant VER integration needs, instead of stopping at 15 minutes.

The bulk of RenewElec's comments address the Commission's proposed amendments to: (1) the *pro forma* Large Generator Interconnection Agreement (LGIA) to require the provision of meteorological and operational data by interconnecting VERs to transmission providers, and (2) the *pro forma* Open Access Transmission Tariff (OATT) to permit transmission providers to propose differentiated generator regulation and frequency response charges in Schedule 10 based on only one year of data.

RenewElec's comments support a broadening of the VER data provision proposal to require retroactive amendments to existing LGIAs, and to amend the *pro forma* Small Generator Interconnection Agreement (SGIA) to include similar data provision requirements applicable to all interconnection customers whose generating facilities are VERs with a capacity of 3 MW or larger and to interconnection customers whose generating facilities are solar VERs with a capacity of 1 MW or larger.

With respect to the proposed differentiated Schedule 10 option, the comments discuss findings in RenewElec's research that suggest the Commission should reconsider its proposal and, at a minimum, set forth specific factors that public utility transmission providers must demonstrate having considered in developing VER-specific Schedule 10 charges.

The RenewElec Project's current body of research and analysis provide four important areas of caution that drive its recommendations. The first two reflect general infirmity in the present status of the data. The second two relate directly to the appropriateness of any proposal for VER-differentiated regulation and frequency response charged under Schedule 10. These areas of caution to the Commission are:

(1) the current limitations in the VER forecasting studies upon which the Commission relies and the need to identify the rather high levels of uncertainty inherent in today's methodologies;

(2) only collection of meteorological and operational VER data for a multi-year period can provide a level of confidence for purposes of either forecasting or academic inquiry sufficient to meet the public interest benefit test of Section 205 of the Federal Power Act;

(3) the correlation between the variability any given wind farm introduces to the transmission system, the capacity factor of that farm and the disparities among individual wind farms in a region; and

(4) the unique cost-effectiveness of managing and reducing variability of VERs through energy storage, underestimation of which could lead to overestimation of reserve requirements for an entire Balancing Area or for units that use storage to regulate variability.

IV. COMMENTS

A. Intra-hour Scheduling

RenewElec commends the Commission for its proposal to require intra-hour scheduling. More frequent scheduling reduces both the amount of uncertainty in matching the output of VERs to load and thus reduces the amount of regulation reserves that the transmission provider must procure. The Commission's proposed rule on intra-hour scheduling will reduce the scope of risk and cost exposure of transmission systems.[3] RenewElec's research supports this decision,

[3] VER NOPR at P 41.

affirming that the variability of wind and solar plants is a strong and predictable function of the time frame involved, and that scheduling on an intra-hour basis is well justified by the data.[4]

However, 15-minute dispatch intervals may not be sufficiently refined for public utility transmission providers aiming to achieve very high levels of VER integration. For designated public utility transmission providers with significant VER integration needs (*e.g.,* areas with renewable portfolio standards), RenewElec recommends that the Commission require these utilities to move as expeditiously as possible to 5-minute scheduling intervals. Five minutes intervals are already common in organized market regions, are technically feasible, and will ensure that VER dispatch is conducted at the maximum achievable accuracy and efficiency. Alternatively, the Commission could consider a phased transition to 5-minute scheduling that allow a designated public utility transmission provider to implement 15-minute schedule as an interim step on the way to implementing 5-minute scheduling according to a firm timeline.

B. Forecasting

1. Current wind and solar power production forecasting methodologies are still too immature to rely on for the long-term

The Commission properly acknowledges that even though the sophistication of power production forecasting has evolved significantly in recent years, the methodologies underlying the current state of the art in forecasting are still "imperfect" and likely to evolve further in the

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[4] *See, e.g.,* J. Apt, *The Spectrum of Power from Wind Turbines.* Journal of Power Sources, Vol. 169, No. 2, at 369-374 (2007): W. Katzenstein, E. Fertig, & J. Apt, *The Variability of Interconnected Wind Plants*, Energy Policy, Vol. 38, No. 8, at 4400-4410 (2010); and A. Curtright & J. Apt, *The Character of Power Output from Utility-Scale Photovoltaic Systems,* Progress in Photovoltaics, Vol. 16, No. 3, at 241-247 (2008).

coming years.[5] In doing so, the Commission refers to several studies,[6] most of which RenewElec reviewed and critiqued in a white paper delivered in October 2010.[7] RenewElec found that the studies examined in the VER NOPR are incomplete, in part because they either use anemometer measurements or data from meteorological models to produce wind speed data but rarely systematically compare and contrast the data from the two sources.[8] These studies also largely overlook or misunderstand the impact of higher frequency wind variability.[9]

In addition, all of the studies assume, to varying extent, that wind varies according to Gaussian (bell-curve) statistical models, an assumption that is not supported by empirical data.[10] Rather, the empirical data show that extreme events (*e.g.*, cases of many days with no wind or excessive wind, or very rapid decreases from full power production to lower power production) are much more common than bell-curve statistics would predict. All of the studies reviewed suggest that geographical diversity in wind resources would reduce wind power output

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[5] VER NOPR at P 45.

[6] VER NOPR at PP 45–46.

[7] P. Jaramillo & P. Hines, *A Review of Large-Scale Renewable Electricity Integration Studies*, RenewElec White Paper, Carnegie Mellon University and University of Vermont (October 2010), available online at: http://www.renewelec.org/workshops/Integration%20studies.pdf (studies reviewed include NERC, Integration of Variable Generation Task Force, *Task 2.1 Report: Variable Generation Power Forecasting for Operations* (2010); National Renewable Energy Laboratory, *Eastern Wind Integration Study* (2010); Charles River Assoc., *SPP WITF Wind Integration Study* (2010)).

[8] *Id.* at 3.

[9] Many studies the Commission examines and RenewElec reviewed were primarily based on data sampled at a rate of 1 to 12 samples per hour, which can result in misunderstanding the impact of higher frequency variability. *Id.* at 2.

[10] *Id.*

variability. This variability is the precise factor that power production forecasts must capture to ensure accurate and efficient scheduling, and for designing appropriate generator regulation and frequency response charges. But despite the central importance of this factor, no detailed, quantitative analyses of the impact of geographical diversity on variability were performed.

At present, forecasting for wind power production continues to have high error rates, particularly in Balancing Areas where data are limited. The state of solar power production forecasting is even more immature, given the nascent state of utility-scale solar generation, the lack of data from existing generation, and the inherent complexities of meteorological data required for solar forecasting (*e.g.*, cloud modeling at very small spatial scales).[11]

RenewElec recognizes the need for the Commission to take basic, near-term steps to promote the integration of VERs and that the formulation and incorporation of power production forecasting into scheduling and unit commitment processes is an essential step in that process, but RenewElec cautions against locking in forecasting methodologies based on insufficient data and flawed methodologies. This could have unintended negative consequences for VER integration and the cost of overall system management. Basing the Schedule 10 and intra-hour rate schedules on VER power production forecasting methodologies that are constantly being updated and still have significant room for improvement, could result in over- or under-estimation of generator regulation and frequency response reserve requirements and less efficient intra-hour scheduling. Overestimation or underestimation of reserve requirements resulting from inaccurate forecasting could also distort transmission planning processes.

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[11] VER NOPR at PP 53-54 (citing Comments of the Solar Energy Industries Association in Docket No. RM10-11-000) (filed Apr. 12, 2010).

2. One year of operational and meteorological data is unlikely to offer a reliable basis for accurate VER power production forecasting

The NOPR proposes that filings by transmission providers proposing "different volumetric requirements for different subsets of transmission customers should be supported with actual data collected over a one-year period subsequent to the implementation of intra-hour scheduling and power production forecasting for VERs."[12] RenewElec strongly suggests that one year of data will be insufficient to support a VER-specific regulation charge that purports to represent average reserve requirements. To ensure VER-only Schedule 10 rates will be just and reasonable, the Commission should require transmission providers to retain data provided under the new *pro forma* LGIA Article 8.4 for at least 10 years and commit to performing annual follow-up studies over a period of not less than five years that update power production forecasts with new data received.

There are practical difficulties in balancing the methodological limitations of forecasts based on one year of data and the need to encourage the implementation of charges that are better tailored to meeting the needs of VER integration as soon as possible. But RenewElec suggests that the Commission could strike a better balance by including a biannual re-opener provision for VER-specific Schedule 10 charges, or through other review and implementation combinations.

Power production forecasting and most analyses of the effects of wind integration tend to assume that variability in wind and wind power output follows normal (bell-shaped curve)

[12] VER NOPR at P 107.

Gaussian statistics. Bell-shaped curve statistics greatly under-estimate the occurrence of “black swan” events like the January 2009 calm in the Pacific Northwest, during which 1500 MW of turbines in the Bonneville Power Administration area were idled for 11 continuous days (Figure 1).

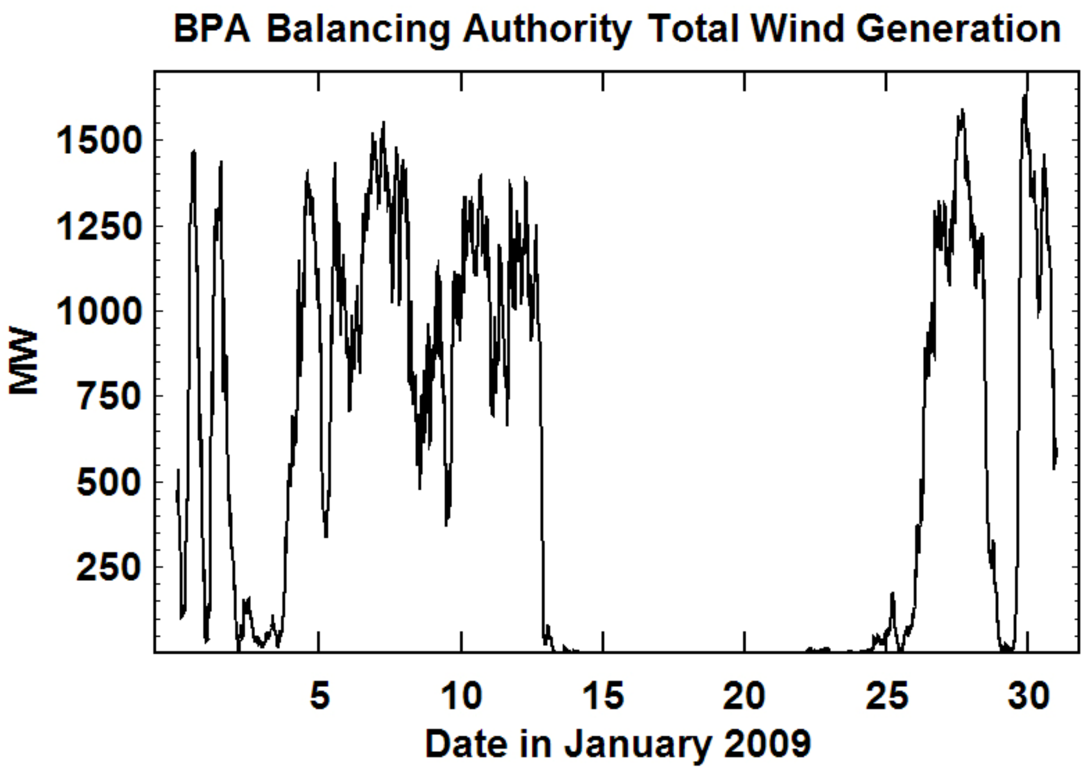

Figure 1. Total wind generation in the Bonneville Power Administration Balancing Area in January 2009.[13]

Long-term wind power generation and forecast data collection at high time resolution (collection intervals of 15 minutes or shorter) is required to characterize the appropriate statistics. An archive of many years of data accessible by research teams is required to allow proper

[13] BPA 2009 wind load data, available online at : *http://transmission.bpa.gov/business/operations/wind/TotalWindLoad_5Min_09.xls*

planning by regulators and operators (further discussion of the need for data publication for interested parties is in the next section). Such an archive exists for hydroelectric power production, which has revealed that such power production is affected by substantial and enduring droughts that occur roughly once per decade, with less severe and lengthy droughts also occurring roughly every decade. We have no direct, country-wide evidence for or against such "black swan" events for wind. However, there is some indication from 35 years of airport anemometer data that there may be "wind droughts," although their frequency and severity is not yet understood.

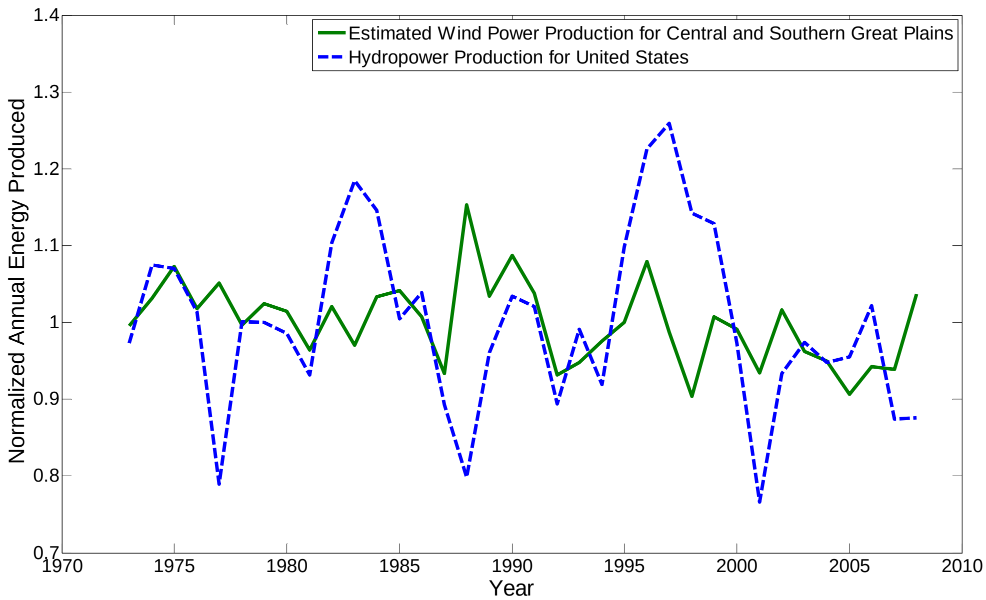

Figure 2. Normalized predicted annual wind energy production from wind farms, based on data from 16 airports located throughout the central and southern Great Plains from 1973-2008. The normalized annual hydropower production for the United States is also plotted for comparison.[14]

[14] W. Katzenstein, E. Fertig, & J. Apt, *The Variability of Interconnected Wind Plants*, Energy Policy, Vol. 38, No. 8, at 4400-4410 (2010).

Given the occurrence—in a single month not later repeated—of the "wind drought" in the Bonneville area as well as the sudden drop of wind in Texas in 2008, it should be apparent that the year of data proposed by the Commission as the minimum for developing VER-specific Schedule 10 charges will reflect conditions only during that time. The data may be quite unrepresentative of the large contingency events that might enter into the reserve calculation. Conversely, if a high impact event occurs during the single year during which data collection is required, it may improperly inflate the cost and amount of reserve capacity deemed appropriate for the tailored Schedule 10 charge.

Finally, one year of data is insufficient to capture the changes in capacity factors of wind farms and other VER behavior that occur from year-to-year. In work now under review for publication, RenewElec research has found that in Texas, three of the four least-cost wind plants in 2008 were three of the ten wind plants with the highest variability cost in 2009.[15] Eight of the 20 wind plants change their rank by two spots or less. This indicates some wind plants are persistent in their variability costs while others vary significantly year to year.

For the aforementioned reasons, RenewElec recommends that the Commission set forth a data retention requirement in the new *pro forma* LGIA Article 8.4 requiring transmission providers to maintain data collected from interconnection customers whose generating facilities are VERs for at least 10 years and commit to performing annual follow-up studies over a period of not less than five years that update power production forecasts with new data received.

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[15] Katzenstein, W. & J. Apt, *The Cost of Wind Power Variability*, Carnegie Mellon Electricity Industry Center Working Paper CEIC -10-05, available online at: *http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-10-05.asp*.

B. VER Data Requirements and Publication

1. Existing LGIAs should be amended to require the provision of meteorological and operating data

The Commission seeks comment on whether its proposal not to require retroactive changes to large generator interconnection agreements already in effect will prevent public utility transmission providers from effectively implementing power production forecasting.[16] RenewElec suggests that the answer is yes—the failure to include existing projects will severely limit the efficacy of power production forecasting.

Over the last ten years, wind capacity grew from 2.4 GW to 34.3 GW.[17] Many, if not all, wind generating facility operators have been collecting meteorological data and producing forecasts to support their operational decisions. It would be useful if the data that these operators have collected became available. This would allow public utility transmission providers (and other interested parties) to gain a better understanding of the variability of wind. These data would also be useful in understanding VER power production forecast errors, which in turn, would improve the accuracy and transparency of VER-differentiated, volumetric Schedule 10 charges.

It is not clear whether the Commission, by not making these requirements retroactive, would exempt interconnection customers whose generating facilities are current wind-based VERs from providing telemetry data in the future. Existing wind plants are farther along on the

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[16] VER NOPR at P 64.

[17] Energy Information Administration, 2008-2009 Wind Data (released Jan. 2011), available online at: http://www.eia.doe.gov/cneaf/solar.renewables/page/wind/wind.html.

operating learning curve and there may be lessons to be learned by collecting their data in the future.

2. Apply data requirements to SGIA, for small solar VERs especially (P 65)

The Commission requests comment on whether the proposed revisions to data provision requirements of the *pro forma* LGIA should also be applied to generators with capacities of less than 20 MW, and therefore require an amendment to the *pro forma* SGIA.[18] Wind farms are generally larger than 20 MW, so this limit may be appropriate for wind resources. The vast majority of utility-scale solar projects, however, are smaller than 20 MW. If the rules proposed here apply only to generators larger than 20 MW, most of the nation's solar generating facilities will be exempted from the data provision requirements, despite the crucial importance of improving the quality and granularity of operational and meteorological data relevant to forecasting solar power production.

To avoid such a result, RenewElec recommends that the Commission amend the *pro forma* SGIA in a tailored manner to ensure that crucially important data is provided to transmission providers without unduly burdening interconnection customers with very small VER facilities (*e.g.*, residential rooftop solar photovoltaic installations). To strike this balance, RenewElec encourages the Commission to include the data provision requirements under the proposed amendment to the *pro forma* LGIA to the *pro forma* SGIA for all interconnection customers whose generating facilities are VERs with a capacity of 3 MW or greater, and to those

[18] VER NOPR at P 65.

interconnection customers whose generating facilities are solar VERs with a capacity of 1 MW or greater.

This proposal accords with the Commission's rationale for requiring large generation VER interconnection customers to report any outages of 1 MW or more. Data at the 1 MW "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."[19] Without data from solar VER facilities 1 MW or more in capacity, or other VERs 3 MW or greater, transmission providers will not be able to develop VER power production forecasts that account for a small but growing portion of generation in their Balancing Areas.

There has been extremely limited research done on the variability of solar photovoltaic (PV) power production, in particular. There is little, if any, data available to perform geographically large-scale analysis of such variability. Collecting telemetry data and developing solar forecasts will be critical to successfully integrate solar PV. Making these data available to interested parties will also further research efforts to mitigate the variability of solar PV.

3. Need for clarity on publication of VER data (P 63)

The Commission requests comment on "whether public utility transmission providers should be allowed or required to share VER related data received from interconnection

[19] VER NOPR at P 62 (footnote omitted).

customers with other entities, like the source or sink balancing authority area for a transaction, or a government agency, such as NOAA, assuming confidentiality is protected."[20]

There is a significant lack of operational data, and researchers need higher granularity and greater access to a wider range of VER data in order to address the greatest challenges facing VER integration. We thus support the Commission's suggestion that the telemetry data and forecast data be made available to interested parties. The Commission should impose two requirements:

(1) VER data submitted under the LGIA (and the SGIA, consistent with the above proposal) should be made public within 6 months of the date on which such data is submitted by the interconnection customer, consistent with existing confidentiality provisions in the Article 22 of the *pro forma* LGIA, including the time(s) the forecast was made; and

(2) Any operational data, including VER data, used by transmission providers to develop VER power production forecasting should be made available to interested parties. A workable data publication system that adequately protects the legitimate business interests of transmission providers and interconnection customers can be achieved if interested parties are limited to individuals or entities conducting research for non-commercial purposes, and if data are released only to interested parties in a sufficiently anonymized format so that the data provided could not be used for commercial purposes.

RenewElec believes this level of data publication approach is feasible. The Electric Reliability Council of Texas (ERCOT) makes data available for each wind farm at moderate time

[20] *Id.* at P 63.

resolution, and Bonneville Power Administration makes 5-minute wind farm data available. If competitive reasons require it, data release could be delayed several months. However, it is only interested parties, who are *dis*interested in such data for its commercial value, that are likely to be able to elucidate long-term trends that may have substantial effects and could contribute to the development of state-of-the-art forecasting methodologies, which are needed to facilitate large-scale VER integration.

While research is still underway to develop the best available forecasting methodologies, RenewElec encourages the Commission to express its preference for common forecasting methodologies. By requiring public utilities to make their forecast data public, the Commission would enable cutting-edge mathematical techniques developed in universities and other research tools created by third-party research organizations, to contribute to the development of VER integration.

4. Need for a clear definition of "Variable Energy Resource" **(P 64)**

The Commission requests comments on its proposal to define "Variable Energy Resource" in the *pro forma* LGIA as "a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator."[21]

The Commission should clarify that this definition does not intend to exclude from data provision requirements an Interconnection Customer whose renewable generating facility

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[21] VER NOPR at P 64.

provides a variable output, but either self-supplies energy storage on-site or procures offsite energy storage services. Since the "energy source" directly powering a VER generating facility is likely to be solar or wind energy, which cannot be stored or controlled by the owner or operator, the definition of VER and the corresponding data requirements, reasonably should be read to apply to all VERs regardless of the use of energy storage. The Commission should clarify in the Final Rule that such was its intent.

The Commission should further clarify that the use of energy storage or other methods to mitigate variability by VER owners and operators do not undercut the quality and quantity of data provided by VERs. Recent research has shown that a small investment in storage can dramatically smooth the output of wind farms.[22] Wind farm operators that choose to reduce the variability of wind by strategies such as changing blade pitch angle or through the use of storage should not be treated the same as generators that contribute more to system reserves requirements for purposes of Schedule 10 rates as discussed in the following section. However, all VERs, regardless of their use of storage or other efforts to mitigate variability, should be required to provide production and forecast data.

C. Schedule 10

The Commission proposes that the Schedule 10 rate for regulation reserve capacity could be the product of two components (like Schedule 3): a per-unit rate and a volumetric component for regulation reserve capacity.[23] This approach poses a significant risk of inaccurate

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[22] Hittinger, E. J. F. Whitacre & J. Apt, "Compensating for Wind Variability Using Co-Located Natural Gas Generation and Energy Storage," *Energy Systems*, 1 417-439 (2010).

[23] VER NOPR at P 92.

estimations of VER variability and incorrect apportionments of reserve requirements to VERs for two key reasons. First, as explained previously, forecasting errors and incomplete data used to develop such forecasts are likely to be common, and may not be properly accounted for in Schedule 10 rates. Second, VER-differentiated Schedule 10 rates may not account for crucial differences between subtypes of VERs—for example, high capacity wind generation units have a disproportionally smaller impact on variability than lower capacity units. Another important distinction to transmission providers should consider is the difference between VERs that self-supply variability mitigation through energy storage and those that do not.

To address these concerns associated with the volumetric, VER-specific Schedule 10 option, as currently proposed in the NOPR, RenewElec suggests that in the Final Rule the Commission require any proposal to support a VER-specific Schedule 10 charge to address, at a minimum, the following two factors:

Factor #1: How were forecasting error and uncertainties in forecasting methodology accounted for in developing per-unit rates and related estimation of VER reserve requirements?

Factor #2: How does the per-unit impact consider differences between various types of VERs and the use of energy storage or other variability mitigation tools?

The following two subsections detail the rationale for requiring consideration of these two factors in the Schedule 10 filing process.

1. Clarity is needed on how to account for forecasting methodology uncertainty and forecasting error in the development of volumetric, VER-differentiated Schedule 10 rates.

VER power production forecasts used to measure per-unit impacts and estimate reserve requirements may have high error rates or be based on data collected over a one-year period that may feature anomalies (*e.g.*, wind droughts). These forecasts may also not fully account for use of storage or other variability mitigation efforts by transmission customers. Relying on such forecasts could result in unjust and discriminatory rates under Schedule 10 that disproportionately burden VER-related transmission customers.

The Commission has not provided sufficiently specific guidance to transmission providers about how to address the uncertainties of forecast methodology and forecast error into a VER-specific Schedule 10 proposal. The quantity of regulating reserves that will be required to meet reliability requirements will depend to a very large extent on the quality of the forecast data, and the statistical nature of the wind, for an individual VER. The only guidance provided in the NOPR for a transmission provider to develop separate regulation reserve charges for VERs that is different from the proposed and generally applicable Schedule 10 is as follows:

> "A number of commenters indicate that VERs may impose a disproportionate impact on overall system variability, thereby requiring public utility transmission providers to hold a greater per MW amount of regulation reserves for VERs than for load and/or other generation resources. As a general matter, the Commission agrees that regulation reserve costs should be allocated to transmission customers consistent with cost causation principles. Further, the Commission does not propose to mandate a particular method for apportioning the volume of regulation reserves of proposed Schedule 10. Instead, we preliminarily find that each public utility transmission provider should propose a method of apportioning such volumes of regulation reserves, based on the facts and circumstances of its individual system."[24]

> "Alternatively, where a subset of transmission customers causes a public utility transmission provider to procure a different per unit volume of regulation reserves than for other transmission customers, public utility transmission providers may require that subset of transmission customers to purchase, or otherwise account for, a different volume of generator

[24] VER NOPR at P 94 (footnote omitted).

> regulation reserves, commensurate with its relative impacts on the system."[25]

> "Where a public utility transmission provider proposes to require transmission customers who are delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources, it must demonstrate that the volumes of regulation reserves required of those subsets of transmission customers delivering energy from generators located within its balancing authority area are commensurate with their proportionate effect on net system variability and taking account of diversity benefits."[26]

There are several categories of forecast variability/uncertainty that RenewElec has identified that might have a substantial effect on a VER-specific Schedule 10 charge. First, as noted above, the methodologies for forecasting wind differ in approach and have not been systematically reconciled. More important is the need to appreciate the inherent uncertainty/range of variability of each predicted wind power/energy production output from a power production forecast. As explained in the RenewElec paper, "Prediction of Variability," one element of forecast uncertainty is typically characterized using several calculations including mean average error (MAE), root mean square error (RMSE) and standard deviation of errors.[27] The result is an indication of forecast accuracy as a percentage of maximum generation. It is only one element of determining the uncertainty inherent in a forecast because it does not

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[25] *Id.* at P 95.

[26] *Id.* at P 106.

[27] B. Mauch, *Prediction of Variability*, Carnegie Mellon University (Oct. 2010), *available at* http://www.renewelec.org/workshops/REN%20Paper%20Brandon%20Mauch%20v6.pdf.

consider the inter-temporal dependence of forecast errors between points in the time horizon.[28] It also neglects the dependence of forecast accuracy on different weather conditions and seasons. RMSE and MAE values are insufficient to provide confidence intervals for forecast values.

A more appropriate approach to employing forecasts from the perspective of grid management might be to calculate RMSE or MAE values for different weather conditions, seasons, and time of day. It is also appropriate to consider the shapes of the error distributions and the maximum error values, in addition to simple measures like RMSE or MAE. The risk of blackouts is highest during rapid changes in wind generation due to extreme weather conditions. It is during these times that forecast errors tend to be the greatest. It is difficult to estimate the chance of these extreme events from scalar measure of forecast error, such as RMSE or MAE. Ideally, forecast error probability distribution functions (PDF) conditioned on different weather conditions would be used to determine reserve requirements for wind power. This not only gives an indication of the magnitude of errors but also the sign. Costs to the grid arising from positive forecast errors are not symmetrical to costs from negative forecast errors. As noted above, Gaussian (bell-curve) models of forecast error will significantly under-predict the likelihood of extreme deviations from predictions.

More analysis of forecast errors is needed to determine contributions of uncertainty. Uncertainty analysis might provide insight into costs and benefits of investments towards improving wind forecasts. It may also allow a better understanding of confidence intervals of point forecasts. This is especially important during times of highly variable winds where

[28] *Id.* at p. 2.

uncertainty is greatest. A better understanding of forecast uncertainty would provide grid managers the ability to determine the probability of wind generation shortfall.

The principal point of the foregoing discussion for the Commission, however, is to recognize the substantial uncertainty associated with quantifying reserve requirements attributable to VER generation, which could result in over- or under-charging for regulation in public utility transmission providers' proposals for VER-specific Schedule 10 charges. Current forecasting methodologies have significant error rates associated with numerous uncertainties, including variations caused by substantial shifts in wind condition, as well cloud cover and other atmospheric conditions that affect solar generation. Simply permitting transmission providers to collect one year of meteorological data under the reformed LGIA and developing a refined Schedule 10 proposal without requiring those transmission providers to explain how they dealt these kinds of uncertainties may substantially impair the Commission's ability to ensure a just and reasonable rate.

In addition, RenewElec urges the Commission, at a minimum, to require that any VER-differentiated Schedule 10 charge based on one year of data be revisited as more robust data collected over a longer period becomes available to the transmission provider. New data and updated forecasts may indicate a different volume of reserves are required for regulation of VER generator imbalance and frequency response than the volume proposed for VER apportionment under an original Schedule 10 filing. In this case, the transmission provider should be required to re-file its Schedule 10 to reflect these changes. This would ensure that rates remain just and reasonable, and would mitigate the risk of outdated data and unrefined power production forecasts being 'locked in' after just one year of data development.

2. *Differences between types of VERS and regulation and frequency response resources should be considered in developing Schedule 10 rates*

Effects on variability differ based on the type of VER unit being evaluated. Examples of the need to differentiate between VERs are numerous. For example, because the output of a wind turbine increases quickly at intermediate wind speeds, but then reaches a plateau where it is roughly constant as speed increases, a higher capacity factor wind farm has, in general, less variability than a low capacity factor wind farm at which the wind rarely reaches the plateau. This "plateau effect" results in generally less variability for a higher capacity factor wind farm than a low capacity factor wind farm at which the wind rarely reaches the plateau (*See* Figure 3).

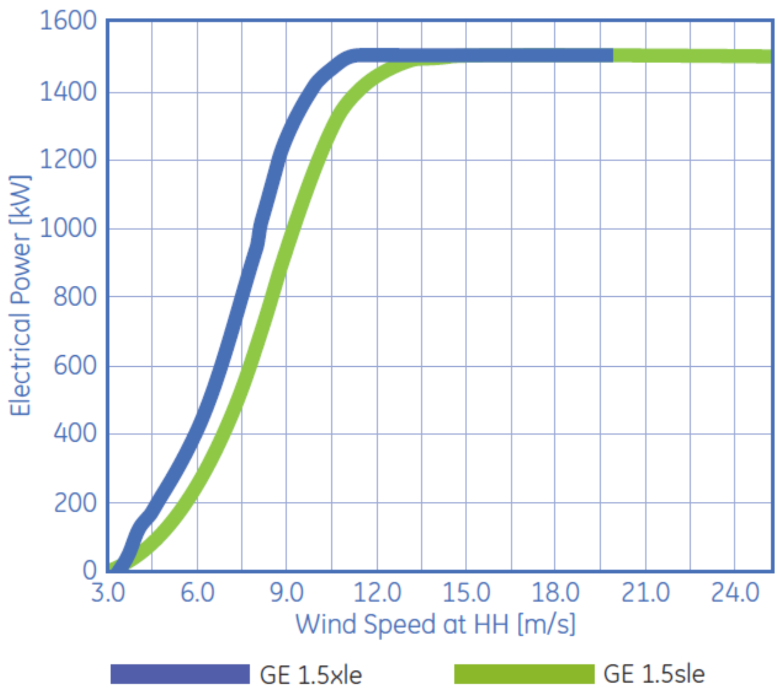

Figure 3. Electrical power output as a function of wind speed at hub height (HH) for a GE 1.5MW turbine.[29]

[29] General Electric Brochure, GEA-14954B (Apr. 2009), *available at* http://www.gepower.com/prod_serv/products/wind_turbines/en/downloads/ge_15_brochure.pdf.

RenewElec's research shows that the variability cost in ERCOT in 2008 was approximately $7 per MWh for wind farms with capacity factors of 38-44%, but was $10 per MWh for those farms with capacity factors below 28%.[30]

Another important distinction between VER units is that those that self-supply, or procure storage-based, regulation services from third parties will not impact variability to the same degree as stand-alone VER generators and conventional generation. A VER unit that has sufficient on-site storage to provide constant power will have a negligible impact on variability and would not increase the regulation requirements. The per-unit effect of a VER that self-supplies with on-site storage may also differ from a VER that procures a "share" of regulation reserve capacity from an off-site, energy storage node. The role of energy storage in managing variability may also not be fully accounted for in the data provided to public utility transmission providers due, in part, to the proposed definition of VER discussed previously. As a result, the cost and volume assessments for unloaded generation and other non-generation resources held in reserve to manage variability of generation reliably may be inflated.

Failure by public utility transmission providers to adequately account for the value of non-generation resources as variability mitigation tools compared to traditional generation-based in developing Schedule 10 rates would also be contrary to the public interest. As the Commission recently recognized in a separate, but related, rulemaking, certain non-generation

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[30] Katzenstein, W. & J. Apt, *The Cost of Wind Power Variability,* Carnegie Mellon Electricity Industry Center Working Paper CEIC-10-05, *available at*: http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-10-05.asp.

resources, like fast-ramping advanced battery storage, can "ramp up or down faster…and … provide frequency regulation services more accurately than traditional resources."[31]

Biases against non-generation resources in the Schedule 10 development process would also fail to capture potentially significant environmental benefits. The choice of dispatchable resources used to regulate VER variability can have a significant effect on air emissions. For example, the standby and ramping NO_x emissions of natural gas turbines used to follow VERs vary significantly with the type of NO_x control system used.[32] The use of gas turbines that have been optimized for steady-state operations to follow VERs will result in significantly increased NO_x emissions compared to the use of gas turbines whose NO_x controls are designed to operate well at lower powers and high ramp rates. The NO_x emissions from a turbine using GE Dry Low NO_x control that is optimized for power levels higher than 65% of rated power (*See* Figure 4 below). NO_x emissions greatly increase when the turbine ramps to lower power levels.

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[31] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Notice of Proposed Rulemaking, 76 Fed. Reg. 11,177 (Mar. 1, 2011), 134 FERC ¶ 61,124 at P 1 (2011) (footnotes omitted).

[32] Katzenstein, W. & J. Apt, *Air Emissions Due To Wind And Solar Power,* Environmental Science & Technology, Vol. 43, No.2, 253-258 (2009); *see also* Katzenstein, W. & J. Apt, *Response to "Comment on 'Air Emissions Due to Wind and Solar Power,' "* Environmental Science & Technology, Vol. 43, No. 15, 6108-6109 (2009).

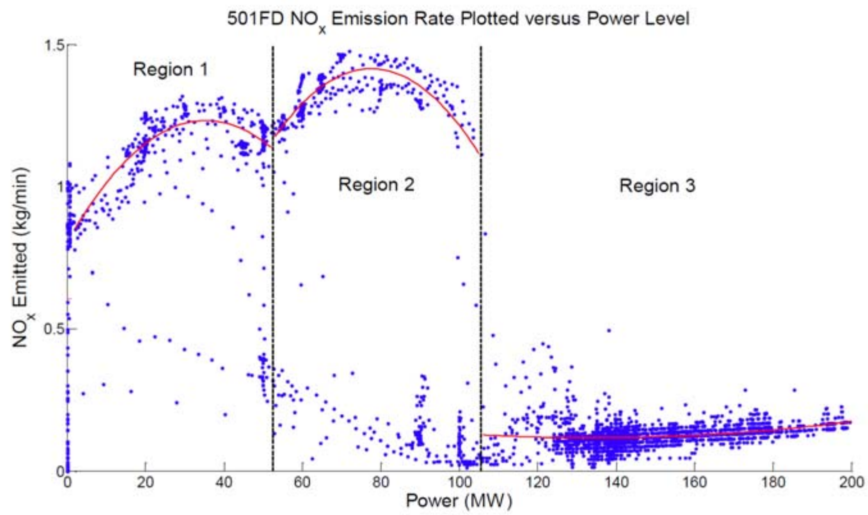

Figure 4. NO_x emission data from a 501FD gas turbine as a function of power (blue dots).[33]

V. CONCLUSION

The RenewElec Project appreciates the opportunity to comment on various aspects of the NOPR. The Commission's concession that reforms proposed in the NOPR are not intended to solve all the challenges facing VER integration is appreciated. RenewElec's primary purpose in these comments is to provide technical assistance to the Commission based on its research to ensure that these basic initial reforms do not have negative unintended consequences and make integration of VERs more efficient and cost-effective. For this reason, we encourage the Commission to strongly consider the proposed modifications herein, which are, in sum:

- 5 minute scheduling for public utility transmission providers with significant VER integration needs;

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[33] *See* Katzenstein, W. & J. Apt, *Air Emissions Due To Wind and Solar Power*, Figure S7.

- Risk mitigation policies to account for inadequacies in the current state of VER power production forecasting and incomplete VER data;
- Data requirements and publication rules that promote accuracy and transparency; and
- Schedule 10 rate filing guidance to ensure consideration of forecasting error, data inaccuracies, and the differences between various types of VERs and regulation resources.

The RenewElec Project requests that the Commission consider the comments provided herein as it develops the Final Rule in this proceeding.

Respectfully submitted,

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