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Variable Generation and Electricity Markets

A living summary of markets and market rules for variable generation in North America

Information compiled through March 2015

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UVIG plans to update this information as regional electricity markets evolve

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Variable Generation and Electricity Markets

The following table addresses market rules for wind and solar power (variable generation, or VG) in key regions of North America. Table entries are responses to the following questions:

- **Scheduling in Energy Markets:** How is wind energy scheduled and procured?
- **Ability of VG to Set Day-Ahead Price:** Can wind bid into a day-ahead market and set the overall market price?
- **Imbalance Settlement:** How are energy imbalances settled—either through a balancing market or another settlement procedure?
- **Ancillary Services Market Structure:** How and what type of ancillary services are procured, at what timeframe, and how are costs allocated?
- **Eligibility of VG to Provide Frequency Response and Inertial Response:** Can VG provide frequency response or inertial response?
- **Eligibility of VG to Provide Up or Down Regulation:** Can VG provide up or down regulation? If so, what are the requirements?
- **Type of VG Forecasting System:** Does VG forecasting play a role, and if so, what type of VG forecasting system is in place?
- **Description of VG Forecasts:** What type of VG forecasts are prepared and at what timeframe?
- **VG Forecast Utilization:** How are the VG forecasts used?
- **VG Forecast Tools/Techniques:** How are VG forecasts prepared, and what tools and techniques are used?
- **Availability of Ramp Forecast:** Is a separate forecast prepared on the potential for VG ramps?
- **VG Forecast Cost Allocation:** Who pays for the VG forecasts?
- **Capacity Market Structure:** How is capacity procured that is needed to ensure reliability?
- **Determination of Capacity Value for VG:** How is capacity value or capacity credit for VG plants calculated?

- **VG Power Management:** Are ramp limits or other restrictions imposed on VG under certain circumstances?
- **Curtailment:** Is VG curtailed, and if so, under what circumstances? How is curtailment implemented? Is compensation provided to VG?
- **Incorporation of VG into System Dispatch/AGC:** Is VG incorporated into system dispatch, and if so, under what conditions?

As a baseline for the table, the discussion of these questions in Federal Energy Regulatory Commission (FERC) Order Nos. 764, 888, and 890 is summarized here:

Scheduling in Energy Markets: No requirement for centralized energy markets.

Imbalance Settlement: Energy imbalance charges may apply if energy deliveries differ by more than +/- 1.5% from advance schedules. Under Order 888, actual penalties or payments for under-deliveries/over-deliveries are left to the discretion of the transmission provider, but they may be substantial. Under Order 890, FERC requires that imbalances of less than or equal to 1.5% of scheduled energy, or up to 2 MW, be netted monthly and settled at the transmission provider's incremental or decremental cost. Imbalances of between 1.5% and 7.5% of scheduled energy, or between 2 and 10 MW (whichever is larger), are settled at 90% of decremental costs and 110% of incremental costs. Imbalances greater than 7.5% (or 10 MW, whichever is larger) would be settled at 75% of the system decremental cost for overscheduling imbalances or 125% of the incremental cost for underscheduling imbalances. Intermittent resources, however, would be settled at 90% of decremental costs and 110% of incremental costs for imbalances greater than 7.5% or 10 MW.

Ancillary Services: Transmission providers are required to offer scheduling and billing services and to act as the purchasing agent for transmission customers that need ancillary services.

Intra-hour Scheduling: Transmission providers are required to offer intra-hour generation and transmission scheduling as an option for their customers.

Wind Forecasting: For new interconnection requests for utility-scale VG plants, Order 764 requires VG to provide meteorological and forced outage data to their transmission utility if the utility has VG forecasting or undertakes it.

Wind Power Management and Capacity Calculation and Recognition for wind are not discussed in Orders 764, 888, and 890.

Variable Generation and Market Rules

I. Scheduling and Settlement

	PJM	NYISO	ISO-NE	Midcontinent ISO
Scheduling in Energy Markets	Permitted to bid into the day-ahead (DA) market. Must bid into the DA market to receive revenues from the capacity market.	Required to bid a price curve (can include negative prices) in real-time (RT), optional for DA. Not required to participate in the DA market to receive capacity revenues.	Can submit bid curve or self-schedule into the DA market (can include negative price bids). Must offer or self-schedule into the RT market if a capacity resource. Proposal under consideration to require wind to submit bid curves and to require wind to bid into the DA market.	VG can be classified as an Intermittent Resource or a Dispatchable Intermittent Resource (DIR). Most VG are DIRs. DIRs are required to participate in the RT market. If an Intermittent Resource or a DIR is designated as a capacity resource, then it must offer into the DA market.
Ability of VG to Set Day-Ahead Price	VG resources that offer into the DA market as economically dispatchable resources are eligible to set price.	VG can set the market price.	VG resources that offer into the DA market as economically dispatchable resources are eligible to set price.	If an Intermittent Resource is designated as a “capacity resource,” it can set the market price if its bid includes an offer price.
Imbalance Settlement	Deviations from DA schedules are settled at the RT price. In addition, balancing operating reserve charges are allocated to VG and other resources for deviations in RT from DA schedules. Differentials less than 5% or 5 MW incur no deviation charges. Generators can self-schedule at a fixed output or within an operating range and will not be assessed balancing operating reserve charges if they follow PJM dispatch directions, and will be eligible for uplift credits, known as operating reserve credits in PJM.	Deviations from DA schedules are settled at the RT price. In real-time, VG is exempt from under-generation penalties.	Deviations from DA schedules are settled at the RT price. VG is exempt from a share of certain uplift charges that are allocated based on deviations.	Requirements differ for Intermittent Resources and DIRs: <ul style="list-style-type: none"> • DIRs subject to uplift charges (termed Revenue Sufficiency Guarantee charges, or RSG, in MISO) for positive scheduling deviations for DA schedules. Eligible for uplift credits. Penalty charges can be imposed if a tolerance band is exceeded for four or more consecutive 5-minute intervals within an hour. • Intermittent Resources subject to uplift charges for positive and negative schedules. Not eligible for uplift credits. VG generators are exempt during events beyond their control, such as wind speed cut out during high wind events.

	SPP	ERCOT	CAISO	Alberta ESO
Scheduling in Energy Markets	VG resources can, but are not required to, offer into the DA market. With limited exceptions, wind plants must register as Dispatchable Variable Energy Resources (DVERs), defined as a VG capable of being incrementally dispatched down by SPP. Registration as a DVER is optional for non-wind plants.	Qualified Scheduling Entities (QSEs) interact with both generating resources and ERCOT, and QSEs submit bids and offers into the DA or RT market.	All VG can bid into the DA market. VG scheduled at their forecasted output in 15-minute intervals at 37.5 minutes prior to the start of each interval. Settled in 15-minute intervals at the 15-minute locational marginal prices (LMPs). VG can also submit economic energy bids; VG resource can be dispatched down to less than forecasted output if LMP is less than the bid price. Older VG facilities can request transitional arrangements until May 2017 or until a new power purchase agreement (PPA) is signed, whichever comes first. For those plants, an hourly schedule is set using a 90-minute-ahead forecast. The hourly schedule is settled at the average of the 5-minute LMPs.	Wind can, but is not required to, submit DA bids. Generators can modify their bids (volume and price) up to two hours before delivery.
Ability of VG to Set Day-Ahead Price	VG can set the market price.	VG can set the market price.	VG can set the market price. The bid floor is -\$150, and can be lowered to -\$300.	Wind generators can set the market price.
Imbalance Settlement	Deviations from DA schedules are settled at the RT price. Can receive uplift credits if cleared in the DA market. Uninstructed resource deviations are subject to charges unless exempted because of high wind or extreme weather conditions.	Deviations from DA schedules are settled at the RT price. Generation resources may be charged a penalty for deviating from ERCOT's RT dispatch points. Wind is charged a penalty when it is given an economic dispatch below its high dispatch limit (or capability) and is generating more than 10% above its basepoint.	Deviations from 15-minute forecasts and 5-minute dispatches are considered <i>instructed</i> imbalance energy and are settled at 5-minute market LMPs. Differences between the 5-minute dispatch and the metered energy are considered <i>uninstructed</i> imbalance energy and are settled at 5-minute market LMPs. For VG under transition arrangements, deviations between the resource's actual energy output and the hourly schedule will be netted over each month. This amount will be settled at the output-weighted average of 5-minute LMPs over the month.	In RT, wind plants required to meet their offer within 5 MW for wind plants 200 MW or less, and within 10 MW for wind plants over 200 MW. Wind plants are granted an exception if actual wind conditions are less than expected. Over-generation is reported to the market monitor, and penalties or fines will likely be imposed.

	Ontario IESO	BPA	Xcel Energy (PSCo)
Scheduling in Energy Markets	<p>All grid-connected wind and solar generators must be market participants with IESO, while wind and solar projects embedded within a distribution system can elect to be market participants or stay as embedded facilities within the host local distribution companies. Market-participating wind and solar resources submit offers into a DA commitment program for their full capability, but are evaluated and scheduled only up to their forecasted quantity.</p> <p>IESO selects generators and imports to meet DA projected load, and guarantees sufficient revenues to cover their costs. That process does not apply to VG. In RT, a market-clearing price is set every five minutes based on bids and offers, and VG can set the RT price.</p>	<p>Sub-hourly scheduling is voluntary. Under BPA's Committed Scheduling Business Practice, wind generators can lower the cost of balancing services by committing to a predetermined schedule amount for a predetermined scheduling period. Specifically, wind projects can commit to 30-minute persistence forecasts on 15-minute schedules, 40-minute persistence forecasts on 15-minute schedules, or 30-minute persistence forecasts on 60-minute schedules. Those not participating can set their schedule value in whatever manner they choose. Wind generators that elect to participate in Committed Scheduling and meet the scheduling accuracy requirements are eligible for a lower wind integration charge (Variable Energy Resource Balancing Service rate, or VERBS, in BPA's terminology) and are exempt from Persistent Deviation penalty charges for Generation Imbalance. Otherwise, generating resources pay a higher monthly VERBS rate and BPA may impose a Persistent Deviation penalty charge (see Imbalance Settlement below).</p>	<p>Follows scheduling protocols under Order 890.</p>
Ability of VG to Set Day-Ahead Price	<p>IESO's DA commitment program (DACP) does not establish a market-clearing price, but selects generators to meet projected DA load.</p>	<p>Not applicable.</p>	<p>Not applicable.</p>

	Ontario IESO	BPA	Xcel Energy (PSCo)
Imbalance Settlement	Market-participating wind and solar generators are required to operate within a compliance deadband, unless wind and solar resources are insufficient and dictate a lowered output.	<p>Imbalance is settled on the shortest scheduling period submitted for the hour at rates based on (1) factors of BPA's incremental cost, which is assumed to be the PowerDex Mid-Columbia Hourly Index; (2) the size of the imbalance; and (3) the direction of the imbalance. Imbalance is charged based on the size of the deviation. Band 1 (less than or equal to 1.5% or 2 MW of scheduled energy, whichever is larger) charge is BPA's incremental cost based on the average of heavy load hours and the average of light load hours for the month. Band 2 (greater than 1.5% or 2 MW and less than or equal to 7.5% or 10 MW, whichever is larger) is 110% of BPA's incremental cost. Band 3 (greater than 7.5% or 10 MW) is 125% of BPA's incremental cost. Wind resources are not subject to Band 3.</p> <p>A penalty charge may also apply when a generator has three or more consecutive hours of either positive or negative schedule deviations. Wind generators can also self-supply imbalances and receive a credit against BPA's wind integration rate. BPA, at its discretion, may waive part or all of the persistence deviation charge for extraordinary circumstances or if customers acted to avoid or minimize the deviation.</p>	Follows Order 890 protocols.
	Arizona Public Service	PacifiCorp	Puget Sound Electric
Scheduling in Energy Markets	Follows Order 890 protocols.	Follows Order 890 protocols. Participates in the RT and DA markets.	Follows Order 890 protocols. Schedule 13 of the PSE Open Access Transmission Tariff (OATT) provides the rate structure for several scheduling options for VG. In general, Schedule 13 outlines persistence-based scheduling for several scheduling durations: hourly, 30-minute, and 15-minute intervals.
Ability of VG to Set Day-Ahead Price	Not applicable.	Wind is never the marginal unit on a DA basis but can be during RT.	Not applicable.
Imbalance Settlement	Follows Order 890 protocols.	Participates in Energy Imbalance Market (EIM) with CAISO that started on a fully binding basis in November 2014. Dispatches on a 5- and 15-minute basis. NV Energy will join in October 2015.	Follows Order 890 protocols. Generator imbalance covered in PSE OATT. Levies integration charge on wind generators. Discounts of 30% and 50% are available for submitting 30-minute-ahead schedules for 30-minute-ahead scheduling and 25-minute-ahead schedules for 15-minute-ahead scheduling, respectively. Will join CAISO/PacifiCorp EIM market in October 2016.

II. Ancillary Services

	PJM	NYISO	ISO-NE	Midcontinent ISO
Ancillary Services Market Structure	DA and RT markets for regulation, synchronized, and supplemental reserves. Ancillary service costs borne by loads.	DA and RT markets simultaneously co-optimized for the procurement of energy, regulation, synchronized, 10-minute non-synchronous, and supplemental reserves. Ancillary service costs borne by loads.	Forward (seasonal) and RT markets for 10-minute synchronized, 10-minute non-synchronized, and supplemental reserves. RT market for regulation. Ancillary service costs borne by loads.	Includes DA and RT markets for regulation, spinning reserves, and supplemental reserves. Providers are paid their opportunity costs. Ancillary service costs borne by load and export schedules.
Eligibility of VG to Provide Frequency Response and Inertial Response	Wind is not precluded from providing these services but must meet eligibility requirements. PJM stakeholders are considering requiring FERC-jurisdictional, inverter-based generators to be capable of active power control, to provide reactive power, to limit ramps, and to ride through voltage or frequency disruptions as required in NERC PRC-024. Proposal would apply only to new interconnection queue requests and would not be retroactive.	Wind is not precluded from providing these services but must meet eligibility requirements.	Wind is not precluded from providing these services but must meet eligibility requirements.	Not allowed presently.
Eligibility of VG to Provide Up or Down Regulation	Wind is not precluded from providing regulation but must meet eligibility requirements. PJM does not have separate up and down regulation markets.	Wind is not precluded from providing regulation but must meet eligibility requirements.	Not allowed presently.	Not allowed presently.
	SPP	ERCOT	CAISO	Alberta ESO
Ancillary Services Market Structure	Provided as a result of the co-optimization of energy and operating reserves markets. Consists of regulation up, regulation down, spinning, and supplemental reserves.	Market for regulation (up and down), spinning, and supplemental reserves (a 30-minute non-spinning reserve service and a 10-minute responsive reserve service). All ancillary service costs are borne by loads.	The DA market accepts bids for ancillary services. CAISO currently procures 100% of its ancillary service requirements in the DA market, with incremental ancillary services procured as needed in the RT market. The services procured include: regulation up, regulation down reserve, spinning reserve, and non-spinning reserve.	DA markets for regulation, spinning, and supplemental reserves.
Eligibility of VG to Provide Frequency Response and Inertial Response	No defined frequency or inertial response requirements. VG can provide such services but are not required to do so.	Wind resources with Standard Generation Interconnection Agreements (SGIAs) signed after January 1, 2010 are required to provide primary frequency response. Maximum contribution from wind limited to 20%. Resources are not paid to provide frequency or inertial response in the ERCOT market.	No requirements for VG to provide frequency or inertial response.	Non-exempt wind assets required to comply with frequency response requirements.

	SPP	ERCOT	CAISO	Alberta ESO
Eligibility of VG to Provide Up or Down Regulation	DVERs are eligible to provide regulation down if they meet eligibility requirements. DVERs are not eligible to provide regulation up, or for that matter, spinning reserves and supplemental reserves.	Wind is not precluded from providing regulation but must meet eligibility requirements.	Wind is permitted to provide up and down regulation, but it must be telemetered and tested in order to do so. CAISO has had no wind plant tested to date.	Current requirements effectively preclude wind from providing regulation, i.e., regulation is procured DA, and suppliers must provide it for 60 minutes.
	Ontario IESO	BPA	Xcel Energy (PSCo)	
Ancillary Services Market Structure	RT markets for regulation, synchronized (spinning) reserve available within ten minutes, non-synchronized reserve available within ten minutes, 30-minute reserve (synchronized and non-synchronized) available within 30 minutes, and supplemental reserves. Additional ancillary services for regulation, reactive, and reliability-must-run are procured via contract. Ancillary service costs are borne by loads.	No centralized ancillary services market. Provides ancillary services under Order 890. Reserves set by percent of wind capacity based on elected scheduling paradigm, ranging from 9% for 15-minute schedules and 30-minute persistence forecasts to 17% for an uncommitted schedule and an assumed hour-ahead schedule and 45-minute persistence forecast. Also running a pilot where BPA can purchase, or transmission customers can self-supply, non-federal balancing reserves to limit curtailments of E-tags for under-generation events.	No regional market in operation. PSCo provides FERC-required ancillary services under Order 890. PSCo participates in Rocky Mountain Reserve Sharing Group that shares contingency reserves with multiple balancing authorities. Proposal to FERC for flex reserve service that applies only to VG has been accepted (December 2014) but not finalized, pending the outcome of settlement proceedings at FERC.	
Eligibility of VG to Provide Frequency Response And Inertial Response	VG is required to provide a minimum frequency response and inertial response (if commercially available) as part of requirements and standards required of generators.	Proposed requirement with no defined implementation date. All new wind projects must have frequency response capability. Wind projects >20 MW would be required to provide over- and under-frequency control in the control systems, and may be required to feather for over-frequency, or if able to feather wind generation in advance, to increase generation for an under-frequency event.	Not explicitly eligible or excluded from providing this capability. Any terms for self-provision of services would be negotiated with the transmission provider.	
Eligibility of VG to Provide Up or Down Regulation	Not allowed presently.	Wind and solar are not precluded from providing regulation but must meet eligibility requirements.	PSCo's wind can provide down regulation. Two-thirds of PSCo wind plants are equipped with automatic generation control (AGC). Xcel's Energy Management System will call upon AGC-equipped wind projects if the operating range of other generating resources is exhausted. Terms for self-provision of ancillary services would be negotiated with the transmission provider.	

	Arizona Public Service	PacifiCorp	Puget Sound Electric
Ancillary Services Market Structure	Follows Order 890 protocols.	Follows Order 890 protocols. Reduces payments to wind qualifying facilities (QFs) in Idaho, Oregon, and Utah to reflect integration costs.	Follows Order 890 protocols.
Eligibility of VG to Provide Frequency Response And Inertial Response	Not currently configured to be able to provide these services.	Not allowed presently.	See below.
Eligibility of VG to Provide Up or Down Regulation	Not currently configured to be able to provide these services.	Not allowed presently.	Drafting a Business Practice for the self-supply of operating reserves. A VG that meets the criteria established in the Business Practice would be eligible to provide operating reserves as self-supply or from third parties.

III. VG Forecasting

	PJM	NYISO	ISO-NE	Midcontinent ISO
Type of VG Forecasting System	Centralized wind forecasting since April 2009. PJM does not currently have a solar power forecasting system.	Centralized wind forecasting system in place since June 2008; used for individual wind plant economic dispatch decisions since May 2009.	Centralized wind forecasting since January 2014. No solar forecast but under consideration.	Centralized wind forecasting since June 2008.
Description of VG Forecasts	<p>Long-term: Provided hourly, from 48 hours ahead to 168 hours ahead.</p> <p>Medium-term: Updated from six hours ahead to 48 hours ahead.</p> <p>Short-term: Updated with frequency of every ten minutes, forecast interval of five minutes for next six hours.</p> <p>Forecast on the following aggregation levels: wind projects; electrically close wind farms; Transmission Owners; Regional – West, Mid-Atlantic; Council – RFC or SERC (currently none in SERC); and PJM RTO.</p>	<p>Medium-term: DA forecasts updated twice daily (4:00 a.m. / 4:00 p.m.), covering the next two operating days.</p> <p>Short-term: Updated every 15 minutes on a 15-minute interval basis, covering an 8-hour time horizon.</p>	<p>Long-term: 7-day aggregate wind forecast for each hour, updated hourly.</p> <p>Medium-term: 48-hour-ahead wind forecast that updates every three hours.</p> <p>Short-term: 4-hour-ahead wind forecast that updates every five minutes.</p> <p>ISO-NE does not forecast solar or intermittent hydro at present.</p>	<p>Long-term: MISO receives hourly updated forecasts for each hour for the next seven days, for the same Commercial Pricing (CP) nodes.</p> <p>Short-term: 5-minute granular forecasts for each CP node (DIRs and non-DIRs, 180+) are provided for the next six hours and are updated every five minutes.</p> <p>Forecast on the following four aggregation levels: CP nodes, zones, regions, and all of MISO.</p>

	PJM	NYISO	ISO-NE	Midcontinent ISO
VG Forecast Utilization	<p>PJM’s medium-term (DA) wind power forecast is made available to the wind plant operators for informational purposes so they can consider it when submitting a DA offer. The medium-term wind power forecast is also used in the DA reliability assessment to predict DA congestion and mitigation strategies, and to determine whether there is sufficient generation scheduled within PJM to meet expected load, transaction schedules, and reserve requirements.</p> <p>A short-term wind power forecast is used in RT to evaluate current-day congestion and to ensure that sufficient generation resources are available to respond to fluctuations in wind power output. A variation of the short-term wind power forecast (based on actual meteorological data) is used to calculate Lost Opportunity Cost for wind resources in PJM’s Operating Reserve Settlement.</p>	<p>Used in determining if enough generation is committed DA to serve forecasted load. RT wind forecast is blended with persistence forecast to develop wind plant schedules in RT commitment (which looks ahead in 15-minute intervals for 2.5 hours), and RT dispatch (which looks ahead in 5- to 15-minute intervals for 60 minutes). 100% persistence used in very short term.</p>	<p>Wind power forecast incorporated into the DA scheduling and commitment process and also the scheduling and commitment update process that occurs periodically within the operating day. ISO-NE does not forecast for solar at present.</p> <p>ISO-NE planning to incorporate 5-minute telemetry of VG plants and short-term wind forecasts into RT operation and will allow for economic dispatch of wind plants. This will be extended to include intermittent hydro. Implementation is anticipated in 2016.</p>	<p>MISO uses an hourly wind forecast to inform their reliability unit commitment, for transmission outage coordination, transmission security, peak load analysis, and potential impact of wind ramps on flowgates.</p> <p>A short-term forecast (5-minute intervals for the next 60 minutes) is used to facilitate participation of the DIR in the economic dispatch process.</p>
VG Forecast Tools/ Techniques	<p>Physical model that uses the numerical weather prediction (NWP) forecasts as input; a combination of three NWP models weighted according to the weather situation and historical performance; site-specific power curves based on historical data; and a shorter-term model (0-10 hours) based on wind power measurements and NWPs.</p>	<p>Uses ensemble forecasts and statistical analysis to prepare wind power forecast. Uses the following inputs: grid point output from regional-scale and global-scale NWP models; measurement data from several meteorological sensors; high-resolution geographical data; and meteorological and generation data from wind projects.</p>	<p>The vendor combines plant-specific information (5-minute meteorological data) with several macro weather forecast models, plus detailed information on the turbine characteristics, performance, and current status (for example, in-service, planned maintenance, unplanned outage) to produce an output forecast for each wind plant.</p>	<p>Physical model consisting of a combination of three NWP models weighted according to the weather situation and historical performance; site-specific power curves based on historical data; and a shorter-term model (0-10 hours) is also run based on wind power measurements and NWP input.</p>
Availability of Ramp Forecast	<p>Updated every ten minutes at 5-minute intervals for next six hours. Currently under evaluation for potential use in operations.</p>	<p>No separate ramp forecast; under consideration.</p>	<p>No separate ramp forecast.</p>	<p>No separate ramp forecast; under consideration.</p>

	PJM	NYISO	ISO-NE	Midcontinent ISO
VG Forecast Cost Allocation	PJM pays for the central wind power forecasting service; costs are assigned to load.	Fee assessed to each wind project. Charge includes the sum of a monthly fee of \$500 and a separate monthly fee of \$7.50 per MW of nameplate capacity. Fees are subject to change as more wind projects are added.	ISO-NE pays for the central wind power forecasting service; costs are assigned to load.	MISO pays for the central wind power forecasting service; costs are assigned to load.
	SPP	ERCOT	CAISO	Alberta ESO
Type of VG Forecasting System	Centralized wind forecasting since January 2011.	Centralized wind forecasting since July 2008. Began solar forecasting in January 2015.	Centralized wind forecasting since 2004.	Centralized wind forecasting since January 2010.
Description of VG Forecasts	<p>Long-term: Hourly forecast for each hour from 25 hours to 48 hours, updated every 4-6 hours.</p> <p>Medium-term: Hourly forecast for the upcoming 24-hour period, updated hourly.</p> <p>Short-term: 5-minute forecast for two hours ahead, updated every five minutes.</p>	<p>Short-Term Wind Power Forecast (STWPF): Hourly 50% probability of exceedance forecast for an upcoming 48-hour period, updated hourly and delivered 15 minutes past the hour. Similarly, an 80% probability of exceedance forecast is also provided.</p>	<p>Medium-term: Hourly forecast for each hour of next nine days, delivered daily by 5:30 a.m. Not updated during the day. 20% and 80% probability of exceedance values applied.</p> <p>Short-term: 5-minute forecast for the next six hours, delivered every five minutes.</p>	<p>Medium-term: DA, updated every six hours and covers up to seven days ahead.</p> <p>Short-term: Hourly, updated every ten minutes.</p>
VG Forecast Utilization	Wind forecast is currently used for reliability, capacity, and next-day planning. Also used to determine validity of DA offers and for unit commitment.	<p>QSEs representing wind resources must use the most recently provided STWPF in their Current Operating Plans (COPs). The COPs are then used in both the DA and Hour-Ahead Reliability Unit Commitment Studies which ensure that an adequate amount of capacity is available to reliably operate the system. QSEs shall adjust the provided forecasts for any unreported unavailability.</p> <p>Wind forecast errors are also used as an input in determining monthly requirements of non-spinning reserves.</p>	The DA wind generation forecast is advisory; the short-term forecast is used as the energy schedule for RT operations.	AESO uses medium-term (DA) wind forecasts to project their need for operating reserves and ensure resource adequacy. Short-term forecasts are used for RT dispatch. More specifically, AESO incorporates the short-term forecast (up to 12 hours ahead) into a dispatch decision support tool that is connected to their energy management system.

	SPP	ERCOT	CAISO	Alberta ESO
VG Forecast Tools/ Techniques	Three different NWP models are used, with one that is run every six hours and two that are run every 12 hours. Forecasts are combined after accounting for forecast performance and current weather regimes. Very short-term forecast (0-6 hours) is performed, taking current generation into account.	Days ahead: Uses an ensemble composite of statistically adjusted NWP forecasts. Hours ahead: Uses time series methods, feature detection algorithms, and a rapid update NWP model in addition to the ensemble composite above.	Uses ensemble forecasts and statistical analysis to prepare wind power forecast. Uses the following inputs: grid point output from regional-scale and global-scale NWP models; measurement data from several meteorological sensors; high-resolution geographical data; and meteorological and generation data from wind projects. Forecasts solar distributed generation by mapping solar capacity to weather regions and modeling each weather region by the position and angle of the sun throughout. The capacity of installed panels, efficiency of the solar panel, the cloud cover forecast, and the spatial diversity of the solar projects are also incorporated.	Forecasting vendor uses a short-range ensemble prediction system based on a multi-scheme approach, which is an integrated weather forecasting system that uses 75 individual forecasts to replicate weather uncertainty for the next six days. Each ensemble member is based on a single NWP kernel, where the ensemble members are generated by varying dynamic and physical processes within the NWP model. Thirteen forecasts are provided to AESO, and these are grouped for short-term forecasting. AESO evaluates the forecasts with a persistence forecast and applies confidence intervals ranging from 10% to 90%.
Availability of Ramp Forecast	No separate ramp forecast. Very short-term forecast (0-6 hours) predicts probabilistic ramping events with predefined confidence ranges per site, including event duration and magnitude.	Separate ramp forecast, known as the ERCOT Large Ramp Alert System (ELRAS), forecasts probabilistic ramping events of a predefined magnitude and duration. ELRAS generates 15-minute regional and system-wide forecasts for the upcoming six hours, updating every 15 minutes. At present, the ELRAS ramp forecasts are only used by ERCOT's system operators for situational awareness.	Continuing to develop a ramp forecasting tool in conjunction with the Pacific Northwest National Laboratory.	Discontinued its ramp forecast.
VG Forecast Cost Allocation	SPP pays for the central wind power forecasting system; costs are assigned to load.	ERCOT pays for the central wind power forecasting system; costs are assigned to load.	Fee assessed on all eligible intermittent generators of \$0.10/MWh. The CAISO also charges an export fee for energy from facilities exported outside the CAISO balancing area.	A \$/MWh charge to wind generators as per Rider J of the AESO Tariff. Trued-up annually and was \$0.16/MWh in 2014.

	Ontario IESO	BPA	Xcel Energy (PSCo)
Type of VG Forecasting System	Centralized forecast since September 2013. Applies to wind and solar generators with an installed capacity of 5 MW or greater, regardless of whether the project is interconnected to the distribution or transmission system.	Began wind forecasting in December 2009. No solar forecast.	Centralized wind forecasting since October 2009. Developing a solar forecast.
Description of VG Forecasts	Two forecasts: One is divided into 5-minute intervals and is updated every five minutes. A second forecast consists of hourly forecasts and is updated hourly.	The forecast consist of hourly averages and extends out seven days (168 hours). Forecasts update every hour. BPA does not put restriction or guidelines on how external vendors produce the forecasts.	Long-term: week-ahead forecast with hourly granularity, updated every 15 minutes. Short-term: 3-hour-ahead forecast with 15-minute granularity, updated every 15 minutes. PSCo applies a 75% confidence interval around the expected forecast.
VG Forecast Utilization	Hourly forecasts are for the DA commitment process as well as the planning period between the DACP and RT (pre-dispatch). 5-minute forecasts are used for RT dispatch of wind in 5-minute intervals.	Wind power forecasts are used for RT situational awareness, balancing of loads and resources in near and short term, and assistance in scheduling of wind power.	Wind forecasts used for DA planning; used as input into PSCo's DA natural gas purchases. Also used in RT by PSCo system operators for short-term commitment and dispatch, but forecast is not integrated into PSCo's energy management system.
VG Forecast Tools/ Techniques	Provided by an external commercial service.	BPA uses a blend of multiple wind power forecasts that includes forecasts from multiple external vendors and from customer-supplied forecasts. BPA uses an automated algorithm to evaluate forecast quality over the past seven days. The forecast that produces the smallest forecast error most frequently is selected for the next hour. This methodology is run every hour for all wind plants (33) and for each time horizon of the forecast (168 hours). BPA also maintains a network of 20 anemometers, and data is used to support wind forecasting.	Uses a mix of public and private weather forecasts to produce wind forecasts. Forecast is weighed by past performance. Incorporates forecasts without adjustments for curtailment into a unit commitment model for DA planning. Uses persistence forecasting for time horizons less than 15 minutes and blends in persistence forecasts into its 3-hour-ahead forecasts. Has a staff meteorologist to aid in interpreting forecasts. PSCo has begun an R&D project focused on probabilistic forecasts.
Availability of Ramp Forecast	Ramp forecast is provided using data from centralized forecast.	None.	Ramp forecast under research and development by PSCo, but not in use. Experimenting with Doppler radar to better predict ramps.
VG Forecast Cost Allocation	A monthly charge is assessed to all withdrawals (mostly load) from the IESO grid to pay for the centralized forecasting service.	Wind forecasting costs are incorporated into the VG integration charge (BPA calls it the Variable Energy Resource Balancing Service charge).	Xcel pays for the wind forecasting service; costs are assigned to load.
	Arizona Public Service	PacifiCorp	Puget Sound Electric
Type of VG Forecasting System	Centralized wind and solar forecasts.	Centralized wind forecasting system used to provide forecasts to individual wind plants.	Multiple forecasts consisting of subscriptions to external forecasts and forecasts available from BPA. VG can also provide their own forecast to PSE.

	Arizona Public Service	PacifiCorp	Puget Sound Electric
Description of VG Forecasts	<p>Long-term: Week-ahead forecast, updated daily. Also monthly, quarterly, and annual updates for load and all generation.</p> <p>Medium-term: DA forecast that covers the next three days which is updated every hour; solar DA is adjusted as needed.</p> <p>Short-term: RT and hourly short-term forecasts, updated every 15 minutes.</p>	<p>Long-term: Hourly forecasts for the next week.</p> <p>Short-/medium-term: 5-minute forecasts updated every five minutes for the next 48 hours.</p>	<p>Multiple forecast horizons and forecast period granularities. Site-specific and aggregated forecasts available.</p>
VG Forecast Utilization	<p>Uses longer-term forecasts (weekly, monthly, quarterly, and annually) to understand how renewable resources will affect transmission and distribution system operations.</p> <p>Forecasts also used for intra-day and advance unit commitment and for determining amount of reserves needed.</p> <p>Has integrated wind forecast into energy management system, but not solar.</p>	<p>DA forecasts used for scheduling, trading, and estimating operating reserve requirements.</p> <p>RT forecasts are used for estimating reserve requirements and balancing in PacifiCorp's control area.</p>	<p>Used for short-term planning and situational awareness.</p>
VG Forecast Tools/ Techniques	<p>A combination of persistence, NWP, statistical, and weather situational models are used. Currently uses a third-party forecast but working on developing in-house forecasting capabilities. Installing advanced metering infrastructure to increase its ability to look at distributed solar production data.</p>	<p>Vendor-provided wind forecast.</p>	<p>Relies on forecasting services, also has access to on-site meteorological data and RT wind production data.</p>
Availability of Ramp Forecast	<p>Yes.</p>	<p>Yes.</p>	<p>No separate ramp forecast.</p>
VG Forecast Cost Allocation	<p>Costs assigned to variable generators.</p>	<p>PacifiCorp pays for the wind forecast; costs are assigned to load.</p>	<p>PSE pays for the wind forecast; costs are assigned to load.</p>

IV. Capacity Value & Market Structure

	PJM	NYISO	ISO-NE	Midcontinent ISO
Capacity Market Structure	3-year forward market for capacity through the Reliability Pricing Model (RPM), with up to three supplemental annual auctions as needed. LSEs can also self-supply or procure capacity through bilateral contracts.	Monthly and biennial 6-month capacity auctions. LSEs can meet capacity obligation through self-supply, bilateral purchases, or from capacity auctions.	3-year Forward Capacity Market (FCM). LSEs can also self-supply or procure capacity through bilateral contracts.	Prompt-year forward capacity market that is mandatory unless LSEs opt out. LSEs can meet capacity obligation through self-supply, bilateral purchases, or from capacity auctions.
Determination of Capacity Value for VG	3-year rolling average of capacity factor of VG plant between 2:00 and 6:00 p.m. (local time), June through August. Default value used until operating data becomes available (based on class average): 13% of nameplate capacity for wind and 38% for solar.	Capacity factor of VG plant from 2:00 – 6:00 p.m., June through August; and 4:00 – 8:00 p.m., December through February. Default summer capacity value used until operating data becomes available: 10% of nameplate capacity for onshore wind; 38% for offshore wind. Default winter capacity value: 30% of nameplate capacity; 38% for offshore wind. Capacity value for solar PV ranges from 36-46% (summer) to 0-2% (winter).	Unit-specific. Summer capacity credit is the 5-year rolling average from 1:00 – 6:00 p.m., June through September. Winter capacity credit is the 5-year rolling average from 5:00 – 7:00 p.m., October through May. New facilities determine capacity credit based on one year of on-site data.	Uses Effective Load Carrying Capacity (ELCC). Capacity credit currently averages 14.7% for the 2015-2016 planning year (unit-specific). Unit-specific for solar.
	SPP	ERCOT	CAISO	Alberta ESO
Capacity Market Structure	Self-supply or via bilateral transactions.	Self-supply or via bilateral transactions.	Self-supply or via bilateral transactions. In collaboration with the CAISO, the California PUC annually sets capacity requirements for ten areas within California, plus a planning reserve margin (now 15%). CPUC has interim flexible capacity requirements from 2015 through 2017. CAISO implementing flexible capacity requirements based on the largest monthly 3-hour net load ramps. Costs allocated by LSE's average contribution to the five highest 3-hour net load ramps.	No capacity market.

SPP		ERCOT		CAISO		Alberta ESO	
Determination of Capacity Value for VG	Monthly output level that wind plant equals or exceeds 60% of output during the top 3% of load hours. Can use wind or solar data if MW data is unavailable, and if the facility has operated for three years or less. Production data required for facilities in operation for four years or longer.	For wind, the capacity value is the average capacity factor during the top 20 peak load hours for summer and winter for at least the preceding year and up to the prior ten years. The calculation is differentiated for coastal and non-coastal wind plants. For solar, 100% of nameplate capacity up to 200 MW; then the capacity factor during the highest 20 peak load hours for the preceding three years.	For the most recent three years, wind plant output that equals or exceeds 70% of production between 4:00 p.m. and 9:00 p.m., January through March and November through December; and between 1:00 p.m. and 6:00 p.m., April through October. Averaged to get 12 monthly values. Wind projects are assigned to one of six wind areas (Tehachapi, San Geronio, Altamont, Solano, Pacheco Pass, and San Diego). Diversity benefit added if wind area capacity credit higher than individual wind project. Various adjustments if wind project operating less than three years.	Energy-only market; does not determine or estimate the capacity value of wind.			
Ontario IESO				BPA		Xcel Energy (PSCo)	
Capacity Market Structure	No capacity market.	No capacity market.	No capacity market.	Vertically integrated utility that owns capacity or obtains it through bilateral transactions.			
Determination of Capacity Value for VG	Uses GE-MARS model to determine wind and solar capacity contribution to the forecast daily peak demand. Model uses top five contiguous daily peak demand hours for each winter/summer season and shoulder period month. Simulated and actual wind and solar data are used, selecting the lesser value of the two data for each of the hours. Simulated data will be phased out when ten years of actual wind and solar production data are available.	Zero value set for wind for both winter and summer.		PSCo uses a 12.5% capacity credit for wind and between 41% and 47% for solar in its integrated resource planning process.			
Arizona Public Service		PacifiCorp		Puget Sound Electric			
Capacity Market Structure	Vertically integrated utility that owns capacity or obtains it through bilateral transactions.	Vertically integrated utility that owns capacity or obtains it through bilateral transactions.	Vertically integrated utility that owns capacity or obtains it through bilateral transactions.	Vertically integrated utility that owns capacity or obtains it through bilateral transactions.			
Determination of Capacity Value for VG	Average net capacity during the top 90 load hours, divided by the resource's maximum hourly capacity. Capacity value for solar ranges from 45% for residential PV to 100% for concentrating solar plants with storage or combined with natural gas. Wind is assigned a 20% capacity value.	Measured as the capacity factor of wind or solar during hours with the highest loss of load probability.		In PSE's 2013 Integrated Resource Plan, a loss of load probability (LOLP) analysis was conducted to find the incremental capacity equivalent (ICE) of numerous resources, including wind. That analysis found the ICE for PSE's existing wind resources is 10%; an additional 100 MW of wind would be valued at 4%.			

V. VG Grid Management and Dispatch

	PJM	NYISO	ISO-NE	Midcontinent ISO
VG Power Management	PJM does not currently impose any limitations on wind ramp rates.	If a wind plant is the marginal resource, and if necessary, NYISO requires wind plants to reduce their output at a rate of at least 6.7% of nameplate capacity per minute.	Wind plants under 200 MW must keep ramp rates below 20 MW/minute, averaged over five minutes, unless otherwise directed by ISO-NE. For wind plants over 200 MW, maintain ramp rates no more than 10% of nameplate capacity per minute, averaged over five minutes, unless otherwise directed by ISO-NE.	MISO does not currently impose any limitations on ramp rates. In 2016 or 2017, MISO will introduce up and down ramp capability services, whereby a constraint is added to DA and RT markets. If necessary, resources are held back in the current 5-minute dispatch to meet ramp levels in future dispatch intervals. Providers are paid the opportunity cost.
Curtailement	During constrained operations, resources will be redispatched based upon their market offer (the most expensive resource is dispatched down first).	Curtailements are handled as part of the 5-minute economic dispatch, based upon a generator's market offer (the most expensive resource is dispatched down first), including wind.	ISO-NE first curtails generation without a DA commitment to operate. Weak voltage control and over-generation due to low loads and strong wind and hydro tend to be the main causes of curtailment. The current curtailment procedures will be largely displaced by electronic "Do Not Exceed" dispatch in 2016.	DIRs are part of market dispatch. Curtailements resulting from the dispatch of DIRs are based upon market offers (the most expensive resource is dispatched down first).
Incorporation of VG into System Dispatch/AGC	Wind plants must be able to accept dispatch instructions. During constrained operations, PJM will send wind plants a desired MW basepoint and any curtailements should be achieved within 15 minutes or PJM needs to be notified if that is not achievable.	RT economic dispatch, with centralized forecast used as the upper limit. If the dispatch is constrained such that a wind resource is the most expensive resource impacting the constraint, the wind resource's market offer will determine the reduced basepoint for economic dispatch. Wind plants must follow the re-dispatch signal and reduce their output at or below the reduced basepoint output limit within five minutes. Penalties for non-compliance are equal to MW above basepoint multiplied by the regulation clearing price. A 3% error is allowed. Wind is exempt from under-generation charges.	By 2016, ISO-NE plans to revise its dispatch algorithm to send "Do Not Exceed" output limits every five minutes to each wind generator. Proposal to require wind and intermittent hydro to follow dispatch procedures and to submit bid curves is under active discussion for implementation in 2016.	During dispatch in the RT market, a 5-minute forecast value is used as the economical maximum limit for DIRs. DIRs must submit 5-minute wind forecast, which can be updated up to ten minutes before each scheduling interval, or accept MISO's default wind forecast. If there is transmission congestion, DIRs with higher offer prices will be dispatched down first. Intermittent Resources are curtailed out of market for transmission congestion and minimum generation events. Order of curtailment based on the impact on the transmission constraint and priority of transmission service.

	SPP	ERCOT	CAISO	Alberta ESO
VG Power Management	For DVERs <200 MW, the maximum ramp rate cannot exceed 8 MW/minute. For >200 MW, the ramp rate cannot exceed 4% of the DVER's daily maximum generating capacity.	Unless exempted, wind resources must limit their ramp rate to 10% per minute when responding to or being released from an ERCOT deployment.	Flexible ramping constraint for up ramps included in RT unit commitment or the RT pre-dispatch process. Providers are paid the opportunity cost.	AESO has over-frequency control, power limiting, and up-ramp limits. Ramp rate controls must limit up ramps to between 5% and 20% of maximum authorized power. Also, if directed by AESO, wind generators must limit 1-minute power output from exceeding 2% of maximum authorized power.
Curtailement	DVERs dispatched down if LMP is less than offer price. Non-dispatchable VG curtailed manually and outside of economics.	Curtailements are based on market offers, with the most expensive resource dispatched down first.	VG dispatched down in either the 15-minute or 5-minute market if LMP is less than what the generator bid.	Occurs infrequently and is due to transmission congestion or over-supply. If there are transmission constraints, AESO reduces the most costly energy first among all generators, including wind.
Incorporation of VG into System Dispatch/AGC	SPP gives all generation resources, including wind resources, individual dispatch instructions at a 5-minute frequency. Market dispatch for non-dispatchable VEs is simply an echo of current output. Same for DVERs unless the LMP is less than the offer price, at which point the DVER is dispatched down. SPP will issue directives to limit output to specific levels if a RT reliability event occurs.	All generation resources, including wind resources, are given individual dispatch instructions by ERCOT, generally at a 5-minute frequency. However, wind resources are only required to respond to dispatch signals when needed for congestion or when the resource appears not to be economical.	Dispatch occurs every five minutes. VG dispatched at maximum forecasted output. If necessary, the price-quantity offers submitted by each VG plant will determine the reduced basepoint for each VG plant for economic dispatch.	Wind can submit offers into the DA market. The price-quantity offers submitted by each wind plant will determine the reduced basepoint for economic dispatch. Wind projects that do not want to bid can continue to be non-dispatchable price takers.
	Ontario IESO		BPA	Xcel Energy (PSCo)
VG Power Management	IESO does not currently impose any limitations on wind or solar ramp rates. Requests wind and solar generators to provide their ramp capability across their operating range.		All new wind projects >20 MW must have ramp rate limitation capability and governor response capability.	In certain PPAs, PSCo holds the ability to curtail wind during a particular number of hours per year.

	Ontario IESO	BPA	Xcel Energy (PSCo)
Curtailment	Wind and solar output reduced in times of surplus baseload generation or as grid conditions warrant (evaluated economically by scheduling engine). Wind generators compensated for foregone energy if curtailment exceeds annual and lifetime caps; details differ by wind plant.	Three curtailment protocols: Dispatch Standing Order 216 (DSO 216) for when supplies of INC (up) or DEC (down) balancing reserves that are set aside for all non-contingency errors, for both load and all generation, are exhausted (90% depleted); generation limitations by path for over-generation during times of transmission congestion; and Oversupply Management Protocol (OMP) for mitigation of extreme river conditions. For over-generation, BPA limits over-generating facilities to their bilateral scheduled amounts plus an allocation of INC reserves. For under-generation, the E-Tags of the under-performing facilities are curtailed to their actual generation plus an allocation of DEC reserves.	Majority of bilateral contracts do not compensate for curtailments for reasons other than balancing issues, but costs and risks of curtailments are factored into PPAs. Five of 14 wind farms have negotiated blocks of uncompensated curtailment hours. Beyond that, Xcel will compensate for lost energy and the lost value of the production tax credit.
Incorporation of VG into System Dispatch/AGC	When a resource is scheduled for the full forecasted quantity, the resource is given an “informational” dispatch and is allowed to produce to the full amount given adequate wind and solar resources. When a resource is scheduled for a lower value than the forecasted quantity, the resource is given a “mandatory” dispatch and is required to follow the dispatch, unless wind and solar resource conditions dictate a lowered output.	Not applicable, other than the wind power management and curtailment that is explained above.	Uses AGC to position wind farms at their minimum regulating range as needed. AGC is required on all new wind projects and is on two-thirds of all wind farms.
	Arizona Public Service	PacifiCorp	Puget Sound Electric
VG Power Management	Utility-scale solar facilities equipped with smart inverters and can supply or absorb reactive power and provide voltage or frequency ride-through response.	Under general operating conditions, wind power management occurs through economic dispatch. PacifiCorp generally does not currently impose any limitations on wind ramp rates unless PacifiCorp imposes set points to either manually curtail or release a wind project from curtailment. In those cases, a wind plant cannot ramp up or down to its nameplate capacity in less than ten minutes.	PSE controls power generation set points for a subset of the wind resources that operate within the PSE BAA.
Curtailment	Primarily uses take-or-pay contracts with VG, and VG is compensated for any curtailments.	RT or forecast system overloads or other reliability issues may, under certain conditions, require localized curtailment or constraints on output from generation resources, including wind. Curtailment performed manually by system operators based on the cost of generators and accounting for any contractual requirements.	PSE-owned wind resources are affected by BPA’s OMP policy (see curtailment section for BPA). PSE itself does not have an OMP-like curtailment policy for VG that take service from PSE under PSE’s OATT.
Incorporation of VG into System Dispatch/AGC	VG is currently “must take” as produced.	During constrained operations, PacifiCorp will re-dispatch all resources according to each resource’s bid curve.	At this time, PSE does not incorporate AGC into its VG plants.