The Effects of an Increasing Surplus of Energy Generating Capability in the Pacific Northwest

Council Document 2011-09

Introduction

Since its inception, the Northwest power system has been characterized by ongoing change. The early years, dominated by the construction of dams and adding reservoir storage capacity, gave way to a mix of hydro and thermal resources. In recent years, financial incentives and resource mandates, driven by environmental and other concerns, have led to a new wave of renewable resources, predominantly wind power. The new resources are changing the nature of the power system, from planning to operations. While the hydro-dominated Northwest power system has historically been characterized by constrained energy production, the system today is rapidly evolving into one characterized by relative energy abundance.

The evolution toward a system of relatively abundant but less controllable energy resources has raised integration and integration cost allocation questions. One specific concern is that "excess energy" events can be created when high wind and high, or unexpectedly high, hydro runoff coincide. Excess energy events occur when the available wind and water energy can't all be used to generate electricity because of a lack of matching load. Until the states developed dissolved gas limits consistent with the 1977 Clean Water Act, excess energy could be released as water over dam spillways. In more recent years, the dissolved gas limits have constrained the amount of energy that can be released by spilling at hydroelectric facilities. At the same time, financial and contractual terms limit the extent to which operators of wind generation can substitute wind generation with relatively low-cost hydro power. System operators have had to take unusual actions to find load to match the available energy, including at times paying customers to take power. The increase in excess energy events has raised concerns about who should bear their costs.

There are other consequences from the region's new energy abundance that also need to be understood, including the comparative cost of other resource investments and cost allocations. These effects include how an abundance of low variable-cost resources affects wholesale market power prices in general.

The Council has been asked to investigate these issues by the Wind Integration Forum[1] Steering Committee. Concerns about unbundled renewable energy credits (RECs[2]) from Northwest wind

[1] The Wind Integration Forum (WIF) is a joint project of the Council and BPA for the purpose of addressing regional issues around accommodating the unique characteristics of wind generation on the Northwest power system.
[2] Renewable energy credits (RECs) represent the environmental and renewable attributes of renewable energy

projects to serve California's renewable portfolio standard led the Council to include an action item in its Sixth Power Plan to assess the impact of a future unbundled REC market and actions to address potential problems.[3] The Council's concerns under the Northwest Power Act are to plan to add the lowest-cost energy resources to the region's power system and to ensure an adequate, reliable, economical, and efficient power system. The Council's approach in this analysis has been informed by our statutory obligations, with a focus on costs, cost allocations, system adequacy, reliability, and efficiency. This paper presents an initial long-term forecast of the effects of incremental wind generation on the frequency of excess energy events and on the costs and other implications of dealing with these events. The paper also reviews how market prices have been changing, and may change further, due to these developments recognizing the significant limitations of available tools and forecasts to accurately determine the effects of increasing renewable resources in the region. The paper examines some of the cost and equity concerns that have been raised, and presents a number of measures that might use the energy available from regional resources more efficiently. The Council takes no position on the appropriateness of any particular resource, or the measures described that may counter market effects of the growing proportion of low variable-cost resources. A fuller examination and more precise assessment of these issues are expected to be undertaken through the Wind Integration Forum. The analysis contained in this report is an initial step in quantifying the effects of wind generation on markets for the purpose of informing regional processes to further address the issues raised, and bring more detailed analyses to bear where warranted.

Summary

The Northwest is experiencing an increasing abundance of energy generating capability. This energy surplus[4] is due at least in part to the growth of low variable-cost[5] resources that can combine with low variable-cost hydro to substantially exceed demand. Low variable-cost resources like wind are being added to meet state renewable portfolio standards (RPS), contributing to the frequency and severity of excess energy events. "Excess energy events" are defined as periods when combinations of high water, high winds, and low loads result in an inability to convert all the available low variable-cost energy such as wind or hydro into electric power due to insufficient demand. Such events are usually accompanied by low, even negative,

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production. RECs can be transacted as "fully bundled" (delivered with the associated energy), "partially bundled" (the associated energy can be delivered within a specified time), or "fully unbundled" (marketed separately from the associated energy). As states, particularly California, move toward more aggressive and challenging renewable portfolio standards, the rules under which RECs qualify have received increased attention.

[3] The Wind Integration Forum Steering Committee requested that the Council examine the impacts of renewable energy incentives on system dispatch and reliability (January 2009). Sixth Power Plan action item GEN-10 directs the Council to examine the effects of renewable energy incentives with respect to environmental impact, inefficient dispatch, and negative prices.

[4] Throughout this paper, the term "surplus" is used to refer to the growth of energy generating capacity in excess of reliability requirements. Historically, planners sought to ensure sufficient energy availability to meet system adequacy standards. Wind resources brought on to displace fossil generation result in an abundance of low variable-cost energy capability beyond the minimum amounts needed to meet resource adequacy criteria.

[5] Low variable-cost resources are generating facilities with relatively low operating expenses. An important characteristic of such facilities is that they operate more frequently than higher variable cost resources because relatively little is saved by reducing generation. Variable costs are mostly associated with the cost of fuel, which is zero for many renewable energy technologies.

wholesale electric market prices. Stagnant and declining loads due to the economic recession have also significantly contributed to surplus energy conditions.

As with most change, the growing surplus represents both challenges and opportunities. For example, the growing surplus tends to reduce average wholesale electricity prices, benefitting net purchasers out of the market, but presenting economic challenges to net sellers into the market. Market prices can establish a cost signal for new resources so it's important to understand the expected price effects of the growing surplus for resource planning.

While loads are expected to recover over the next several years, RPS resource development is expected to continue in advance of load growth until then. The extent of additional Northwest wind power development to serve the California RPS will depend on California's evolving RPS policy and the availability and cost of competing resources outside the Northwest, especially solar.[6] Retiring the Boardman coal plant and other thermal units may offset the market price effects of additional wind resources. However, retiring thermal plants is not likely to affect the frequency and severity of excess energy events and accompanying low or negative energy prices[7] since thermal units are normally displaced during these events.

The forecasts of excess energy events and their effect on power prices and costs were carried out using an economic model of the power system with a simplified representation of hydropower system operation. The results are relative, not absolute, indications of frequency and magnitude. The Council's Resource Adequacy Forum is working with the Pacific Northwest Utilities Conference Committee (PNUCC), Bonneville Power Administration (BPA), and Northwest utilities on a more refined analysis of the operational effects of increased wind power penetration.

The principal findings of this assessment are:

- Developing resources to serve Northwest state RPS tends to increase the frequency of excess energy events until their final targets are met. After meeting the final targets, in the early to mid-2020s, the frequency of excess energy events is expected to slowly decline.

- Additional wind development beyond Northwest RPS requirements would increase the frequency of excess energy events. Changes to California's RPS signed into law in April 2011 appear to reduce the likelihood of significant renewable resource development in the Northwest to supply California beyond contracts already in place.

- The probability of excess energy events increases during good water years and declines during poor water years. As demonstrated in June 2010, unusual runoff patterns can create excess energy conditions even in average water years.

[6] Solar is of particular significance because development of the relatively abundant California solar resource is expected to reduce pressure to develop wind resources in the Northwest to meet California renewable energy targets.
[7] A negative energy price means that the seller of the energy must pay the purchaser to take delivery. As described in this paper, these conditions can occur when producers experience higher costs as production declines.

- Current RPS targets and financial incentives tend to encourage RPS-qualifying energy production that exceeds load growth. Market prices will also be lower, including the market value of non RPS-qualifying electricity.

- The average impact of lower market prices on the energy value of Northwest generation as a whole will be moderate. The value of hydropower will be particularly affected. Growth in variable generation increases market price volatility.

- Measures are available to reduce the frequency of excess energy events, to alleviate the economic and operational issues associated with excess energy events, to counter equity issues, and to use available low-cost, low-carbon energy more productively. Policy-related measures are generally low-cost and quickly effective, but may be politically difficult to implement. Structural measures tend to be capital-intensive, and may take a long time to implement.

Background

Historically, the combination of high springtime runoff and low electrical loads has periodically led to episodes of excess energy and low market prices in the Pacific Northwest. These episodes occur primarily during the spring runoff period when hydro generation is high and loads are low. Total dissolved gas water quality standards constrain spill, lowering prices by limiting the ability to reduce hydropower generation levels. Periodic episodes of uncontrolled spring floodwaters led to building large reservoirs in the US, entering into the Columbia River Treaty to develop Canadian storage, and building the interties to carry surplus energy to serve California markets.

Dissolved gas levels in rivers are naturally increased by entrainment of air as water passes through rapids and over waterfalls. Gas entrainment also occurs at spillways at the Columbia and Snake River dams and at some tributary dams as water plunges over spillways into stilling basins. At high levels, dissolved gas can be harmful to fish and other aquatic life by causing gas bubble trauma. Spill levels mandated to facilitate downstream fish migration are limited by gas supersaturation “gas caps” required under the federal Clean Water Act.

Hydro-rich utilities aggressively market surplus hydropower during high runoff periods by offering power at low prices, making it attractive for thermal plant operators to curtail operation to save fuel costs and substitute hydropower to serve their loads. Because the dispatch cost of even the lowest cost fossil-fueled resources is $10 - $20 per megawatt hour (MWh), single-digit hydropower offers have been sufficient to displace most thermal generation, both in the Northwest and in California. This has generally been sufficient because, despite constraints on hydro operation (storage and flood control limits, high natural flows, and dissolved gas limits on spill) that can effectively give hydro the equivalent of a negative dispatch cost, the dispatch cost of the remaining generation is above zero.[8] Reducing output at competing generators shifts load to hydropower, minimizing spill.

[8] Start-up and shutdown costs for thermal generation can also result in negative displacement costs for thermal resources if the displacement is for a small or uncertain number of hours.

Large-scale wind development over the past few years has added a new element to this picture. Wind operators receive value in the form of renewable energy credits (RECs) for producing qualifying energy. Production-related financial incentives and RECs mean that wind plant operators lose money when they intentionally limit generation. While thermal generators save fuel costs when they reduce generation, wind generators actually lose money. This is thought to lead to negative market prices because wind plants have to be paid to voluntarily reduce output. Published data is very limited, but market values of RECs have ranged from a few dollars per megawatt hour to as high as $20 to $35 per MWh at times in some parts of the country. In addition, many wind projects receive the federal renewable production tax credit (PTC), currently about $22 per MWh.[9] Although wind projects typically have a small positive variable operating cost, the RPS value and the PTC, if present, can create a negative variable cost. Owners of some facilities may see even greater losses from curtailment, up to prices specified under power purchase agreements, depending on contractual requirements. These economic disincentives for wind project operators to curtail production can help propel market prices to negative levels[10] (producers paying to deliver their energy) and raise equity issues with respect to the costs of spilled hydro or wind energy.

Effects of an energy surplus

Large-scale wind development in the Northwest has been driven by state RPS and various federal and state financial incentives. The purpose of RPS and the various financial incentives include reducing carbon dioxide production and other environmental impacts of electricity production, commercializing new technologies, job creation, and energy security. Twenty-eight states, including Montana, Oregon, Washington, and California, have adopted renewable portfolio standards[11], which mandate that a specified percentage of retail sales be matched with electricity from certain qualifying sources. In various RPS laws across the country, qualifying sources may include various renewable energy resources, new technologies, and in several states, energy efficiency. Because one of the objectives is to encourage development of new renewable resources, energy from existing renewable resources, including hydropower, is largely excluded.[12] RPS targets vary by the type and size of utility, and incrementally increase over time until ultimate penetration levels are achieved.[13] Target levels remain constant thereafter as a percentage of loads.

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[9] Not all renewable energy projects receive the production tax credit. The amount of credit varies by type of resource and has a limited life. Moreover, owners of projects completed in 2009 and 2010 are reported to have taken the option of converting to the federal business energy investment tax credit or U.S. Treasury grant as provided in the American Recovery and Reinvestment Act of 2009.

[10] Note that negative prices during the spring of 2011 for the most part did not reach levels reflecting the value of RECs or production tax credits.

[11] See http://apps1.eere.energy.gov/states/maps/renewable_portfolio_states.cfm. An additional five states have voluntary standards.

[12] Existing hydro facilities were also excluded because of the practical difficulty of setting a single standard that could apply for both utilities that already had a high penetration of hydro and those that did not.

[13] The ultimate penetration targets for Montana and the West Coast states are as follows: California - 33% by 2020; Montana - 15% by 2015; Oregon - 25% by 2025; and Washington - 15% by 2020. RPS provisions are complex and vary by both state and utility type (investor-owned versus consumer-owned). Detailed information concerning the RPS of individual states is provided in the Database of State Incentives for Renewables and Efficiency, www.dsireusa.org.

Several characteristics of RPS resource development contribute to lowering wholesale electric market prices. First, RPS resource development has been outpacing load growth and might be expected to continue doing so until the demand recovers from the depressed economic conditions. Second, RPS resources must operate to produce the qualifying energy. Finally, the variable costs of resource operation are lower than thermal resources.

Developing renewable energy in the Northwest for export in the absence of new transmission transfer capability also depresses wholesale electric market prices. This happens since either the associated energy enters the Northwest market or it displaces other generation that would otherwise have been exported, causing that energy to enter the Northwest market. Market prices are depressed irrespective of bundling requirements. Alternatively, if additional transmission capability is built, prices are bolstered by making additional load accessible by Northwest generation. Although it has been argued that strict bundling, such as within-hour delivery requirements, might reduce the effect on market prices by encouraging new transmission transfer capability, California's April 2011 revised RPS sets a less-strict bundling requirement that is expected to significantly reduce pressure to build resources in the Northwest for California by removing the proximity advantage that Northwest resources previously held.

Depressed market prices can lead to revenue losses to utilities selling into the Northwest market. Resource-short utilities, on the other hand, may benefit from lower market prices. Both high prices and low prices have longer-term incentive effects: high prices encourage entry of supply into the market while low prices encourage increases in demand or the entry of technologies that can benefit from low market prices such as energy storage technologies. In the Northwest, resource additions are primarily dictated by utility planning reserve margins, reducing somewhat the effect of lower prices on regional adequacy. Market prices may have little effect on utility decisions to add dispatchable generation needed to meet peak loads.

Adding low variable-cost resources in advance of load growth can lead to an increasing frequency of excess energy events. Excess energy events are accompanied by low market prices, as asking prices are lowered in an effort to market the abundant supply of low variable-cost resources. Low market prices, indicating the availability of large amounts of low variable-cost energy relative to load, occur during nearly every spring runoff period. As shown in Figure 1, episodes of low market prices occurred in six of the past 11 runoff periods, and appear to be increasing in frequency in recent years. Though the increased frequency of low price episodes corresponds with the rapid growth in Northwest wind generation,[14] other factors are also at play, including: water conditions; runoff patterns; lost industrial loads from the 2001-02 energy crisis; and since 2008, declining loads due to the economic recession.

[14] Installed wind generation in the Northwest reached 1,000 MW in 2005; 2,000 MW in 2007; and roughly 5,000 MW by the end of 2010.

Figure 1: Mid-Columbia daily low off-peak prices - 2000-2010

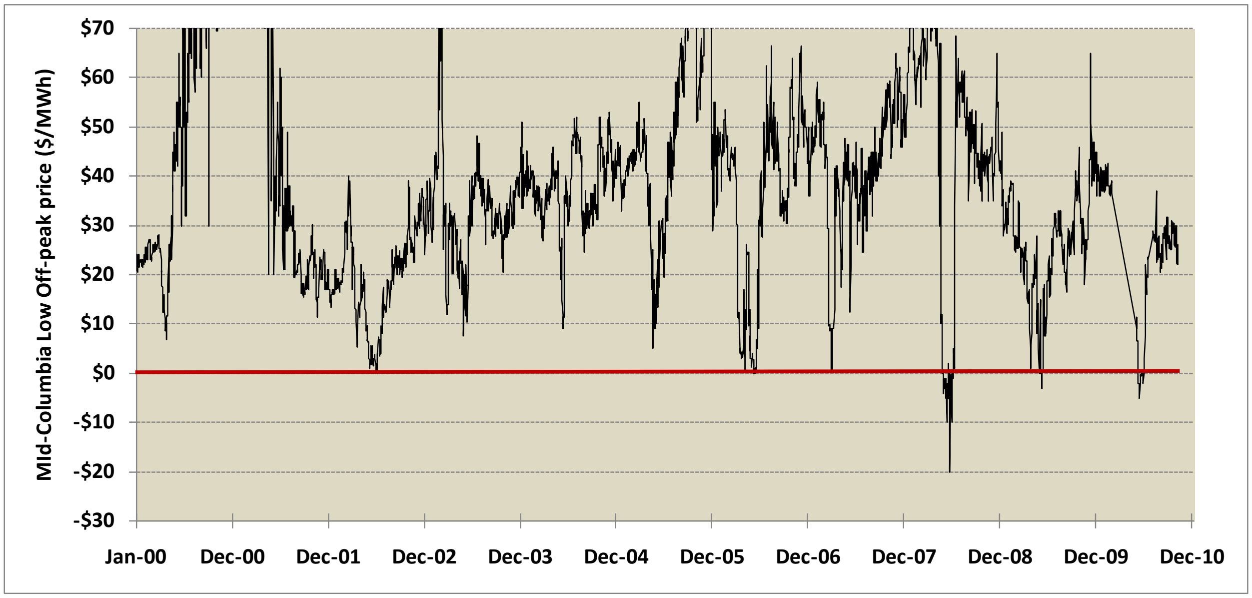


Figure 2 provides a closer look at the June 2010 episode. BPA balancing authority loads and resources are plotted on the left axis for the first half of June 2010. Bonneville load, consisting of native load plus exports net of imports is shown as the shaded area. Load varied between 8,300 and 18,100 megawatts in the typical daily pattern and increased slowly through the period as the warm season advanced. Wind output (green) varied from zero to 2,650 MW in response to the periodic storm fronts typical of spring. Hydropower (blue) followed load net of wind. Hydropower generation increased, on average, through the first two-thirds of the period as runoff increased. Thermal generation (red) was operating at low levels at the beginning of the period, and was reduced to minimum operating levels as runoff increased and dissolved gas levels restricted spill.[15] Some slow-response thermal units, such as the Columbia Generating Station, remained in service at minimum power because of the need to be able to serve loads from any unexpected warm spell.

Mid-Columbia market prices are plotted on the right axis. Note that the zero point of the right axis lies halfway up the axis. Most of the negative price excursions coincide with low load, low hydro, and high-wind hours. Exceptions appear, including the extreme low of -$30 during hour 233.[16] This low price, while coinciding with high-wind output, also coincides with the daily peak load and high-hydro output. Finally, it should be noted that zero or negative prices did occur during some hours of low-wind activity, for example, hours 265 through 272, and 292 through 297.

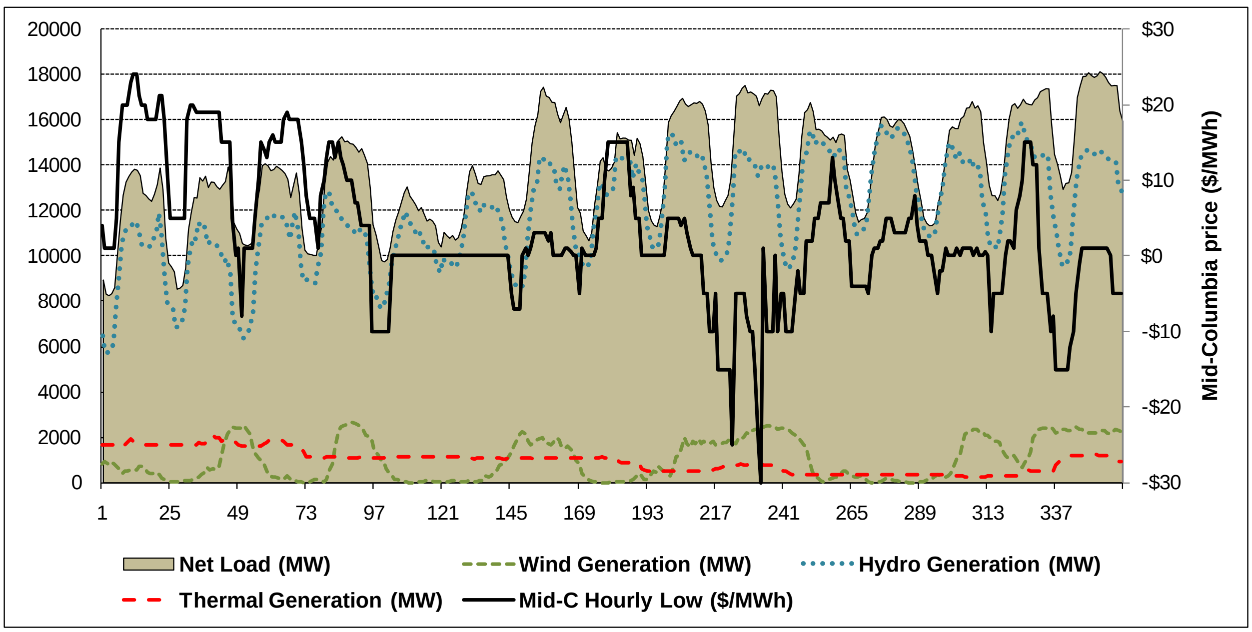
[15] During the period of minimum thermal operation, only 3% to 8% of the 7,500 MW of thermal generation interconnected to the BPA balancing area was operating.

[16] The negative Mid-Columbia spot prices shown in Figure 2 did not result from BPA trading activity. BPA states in *Columbia River high-water operations* that at no point during June 2010 did it offer to sell power at negative prices.

An extensive discussion of the June 2010 episode is provided in BPA's *Columbia River high-water operations*[17] paper.

Spring of 2011 brought even greater challenges than June 2010. An extended cold, wet spring pushed the January through July runoff at The Dalles to 142 million acre-feet[18], fourth highest in the 1970-2005 historical record. BPA adopted two policies in response to the possibility of excess energy events: it would not sell at negative prices (i.e., pay customers to take energy); and it would order wind generators to limit production when spill levels are above limits, hydro turbines are not at capacity, and it cannot market additional energy priced at zero (i.e., offer of free energy).

Figure 2: BPA balancing authority loads and resources and Mid-Columbia market prices: June 1 - 15, 2010



The first wind curtailment BPA ordered was in the early morning hours of May 18, 2011 as gas levels exceeded caps and market prices turned slightly negative. Curtailments were ordered almost daily, usually starting at midnight and lasting several hours. BPA took extraordinary actions to ensure thermal generation within its balancing area were shut down to the extent possible. A total of just less than 100,000 MWh of wind generation were curtailed from May until mid July when the agency signaled that the need for curtailments had largely passed. Wholesale market prices ranged from roughly -$0.25 to -$10 per MWh during curtailment events. Export capability out of the Northwest was not a limiting factor. BPA's action stirred controversy and resulted in complaints filed at the Federal Energy Regulatory Commission (FERC) claiming undue discrimination against wind generation.

[17] *Columbia River High-Water Operations*, September 2010, Bonneville Power Administration: http://www.bpa.gov/corporate/pubs/final-report-columbia-river-high-water-operations.pdf
[18] Northwest River Forecast Center July 7, 2011 Final Forecast.

BPA and the Council jointly hosted a Wind Integration Forum Steering Committee meeting on June 6, 2011 to discuss progress and challenges around integrating wind into the Northwest power system.

Forecast effects of a growing surplus of low variable-cost resources

The frequency of excess energy events, along with the effect of renewable resource development on wholesale energy prices and resource values, were forecast for three cases of future resource development:

Frozen RPS: This case maintains renewable resource development at the level expected to be reached by the end of 2012.

Northwest RPS: This case assumes continued development of a mix of qualifying resources to meet the RPS obligations of Northwest utilities, but no additional development of wind power for RECs to meet California RPS. Adding new wind generation to meet Northwest RPS begins in 2013 and continues through the end of the forecast period.

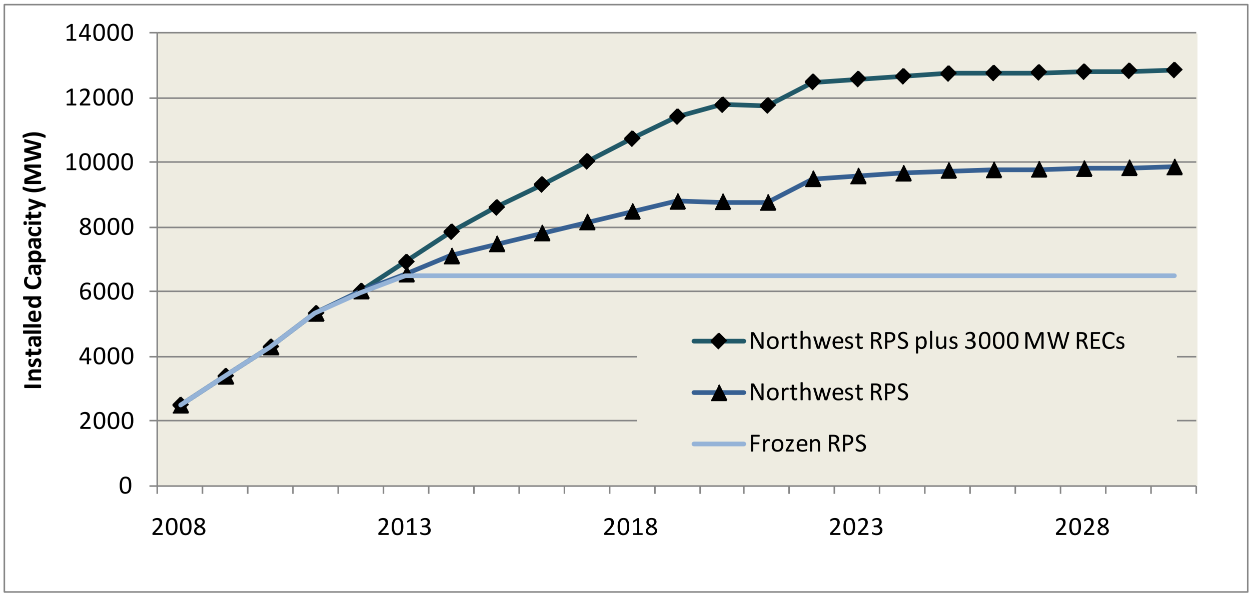
Northwest RPS plus 3,000 REC: This case assumes continued development of a mix of qualifying resources as needed to fully meet the RPS obligations of Northwest utilities, plus developing an additional 3,000 MW of wind generation for export to California with no additional transmission transfer capability. Wind generation to serve California is developed at the rate of 375 MW per year from 2013 through 2020.

In all cases, wind was represented in the model as a must-run resource.

Figure 3 illustrates the build-out of Northwest wind generation for the three cases. The peak penetration of wind nameplate capacity as a percentage of Northwest peak hourly load for the three cases is as follows: *Frozen RPS*: 20 percent; *Northwest RPS*: 29 percent; *Northwest RPS plus 3,000 REC*: 38 percent.

The analysis was performed using the AURORA^{xmp}™ electric market model, using the input data, generation expansion schedules, and principal assumptions of the final wholesale power price forecast of the Sixth Power Plan. Key assumptions used for all cases included average water conditions, the Council's medium-case forecast of natural gas prices, the Council's mean value CO_2 allowance cost trajectory, the energy efficiency targets of the Sixth Power Plan, and the generation expansion forecast (absent RPS resources in the *Frozen RPS* case) used for the final wholesale power price forecast of the Sixth Power Plan. This forecast includes retiring the Boardman coal plant and several other coal and older natural gas combined-cycle units between 2016 and 2022.

Figure 3: Build-out of Northwest wind nameplate capacity for the three cases



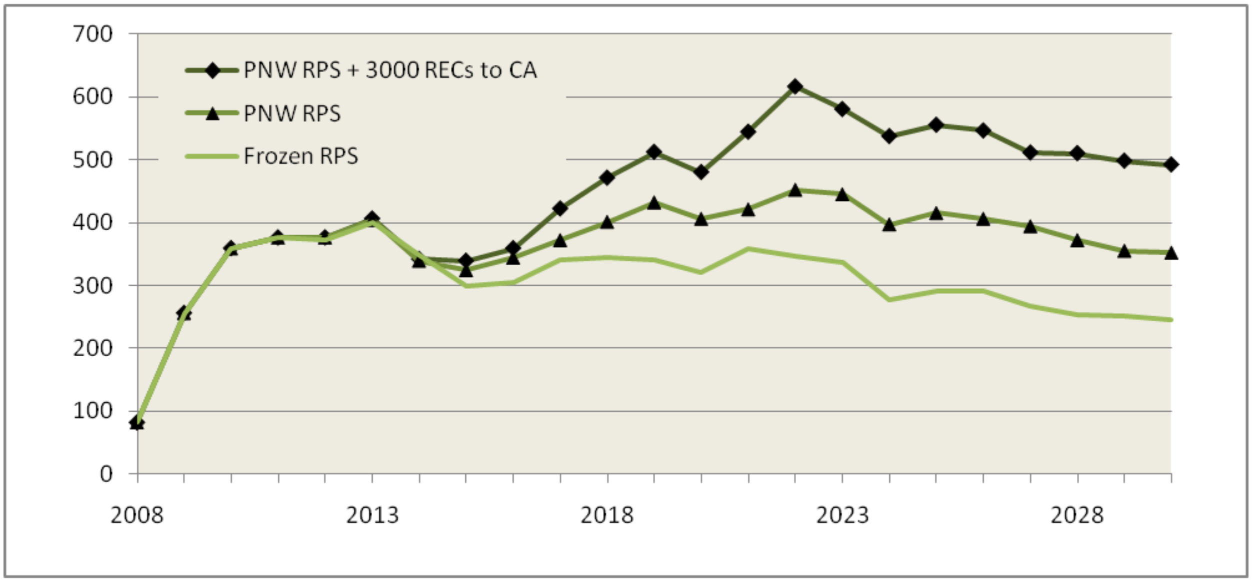
Frequency of excess energy events

Annual hours when regulated Pacific Northwest hydropower output is at or below minimum levels were used as an index of the expected frequency of excess energy events. Because the model cannot explicitly identify spill conditions, hours when regulated hydropower operated at or below[19] minimum hydro generation limits were taken as a proxy index for the relative frequency of spill conditions. The forecast of index of excess energy events is shown in Figure 4 for the three cases.

Regional load growth and resource additions through 2012 are the same for all cases, so the occurrences of excess energy events are identical through 2012. In all cases, excess energy events rapidly increase from 2008 through 2010, and increase at a slower rate through 2013. The rapid expansion of wind generation and stagnant load growth extends from 2008 through 2010. Committed wind additions decline in 2011 and 2012 and loads are forecast to recover from the recession. These factors probably lead to the declining rate of excess energy events from 2010 through 2013. Declines continue in 2014, the likely result of load growth exceeding the relatively modest resource additions for this year.

[19] AURORA^{xmpTM} will intentionally violate minimum hydro operating levels if the sum of minimum hydro generation, must-run generation plus dispatchable generation constrained by operating parameters, less economic exports, exceeds native load.

Figure 4: Forecast of relative changes in excess energy events



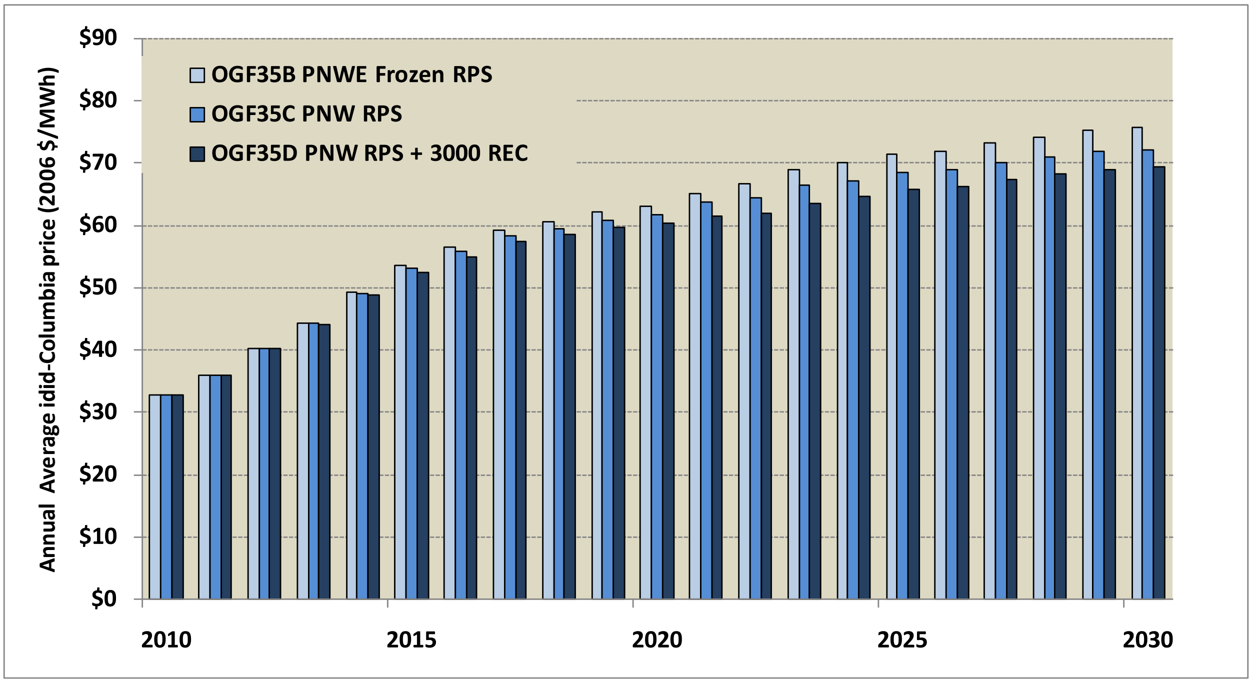
The resource mix of the cases diverges in 2015, as does the relative frequency of excess energy events. In the *Frozen RPS* case, excess energy events decline through the remainder of the forecast period. This is expected, since new firm resources are added only as needed to accommodate load growth, low variable-cost wind and hydropower represent a diminishing share of the power generated, and the production tax credits expire for individual plants following 10 years of operation.[20] Wind penetration continues to increase through 2025 in the *Northwest RPS* case. Minimum hydro events peak in 2022 at 26 percent greater frequency than 2010. Thereafter, the frequency of events declines as RPS targets are achieved, wind penetration is held constant, and hydropower penetration declines as a percentage of load. The *Northwest RPS plus 3,000 REC* case follows a similar pattern but with a more rapid increase, peaking in 2022 at a 72 percent increase over 2010 levels.

Market price effects

Forecast average annual Mid-Columbia prices, in constant 2006 dollars, are shown in Figure 5 for the three cases. The overall shape of the forecast is consistent with the electricity price forecast of the Sixth Power Plan. Prices rise fairly rapidly through 2017 as loads recover from the economic recession, natural gas prices rise, and CO_2 allowance costs phase in. Price increases flatten thereafter as the rate of increase of CO_2 allowance costs declines. Prices are further flattened following 2013 for the two cases involving the addition of new resources in excess of load growth. As expected, adding low variable-cost, must-run wind power depresses average annual prices somewhat. By 2020, the average annual price in the *Northwest RPS* case is 2 percent below the price of the *Frozen RPS* case and the annual average price for the *Northwest RPS + 3,000 REC* case is 4 percent below the *Frozen RPS* case. By 2030, the differences have grown to 5 percent and 8 percent, respectively.

[20] The availability of production tax credits for new plants is assumed to expire as currently scheduled.

Figure 5: Forecast average annual Mid-Columbia spot prices



The energy value of a resource is the difference between energy revenue and its variable cost of operation. As shown in Figure 6, there is little difference in the forecast energy value for the aggregate of Northwest resources among the three cases. Lower market prices in the *Northwest RPS* and *Northwest RPS plus 3,000 REC* cases appear to be offset by the added volume of low variable-cost electricity from the energy generated from new resources present in these cases.

The energy value of hydropower, however, is reduced by the additional resource development of the *PNW RPS* and *PNW RPS plus 3,000 REC* case, as shown in Figure 7. Though some additional energy is assumed to come from upgrades to existing hydropower resources and new hydropower additions, the volume of additional hydro energy is insufficient to offset reduced energy market prices. The value of hydropower is particularly affected because the greatest extent of market price depression occurs in mid-winter and in late spring--the times of greatest hydro generation. This seasonal effect on market prices, as illustrated in Figure 8 for the years 2019 and 2020, appears to result from the seasonal shape of Northwest wind, with peaks in early winter and again in late spring. The wind seasonality used in this analysis is based on information used to develop the Sixth Power Plan and may change as more information is developed about how wind, temperature, and precipitation interact. Note that the price effect due to varying amounts of wind is significantly smaller than the price effect of the spring hydro runoff and low springtime loads in the West.

Figure 6: Energy value of all Northwest resources

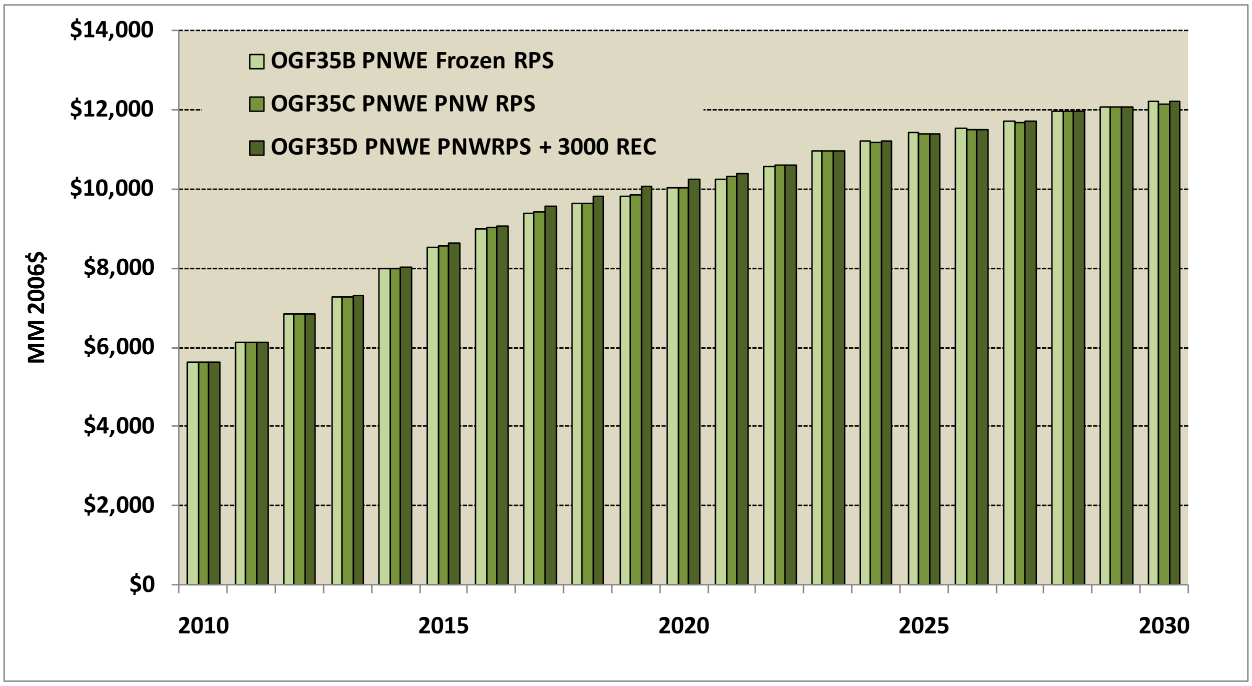
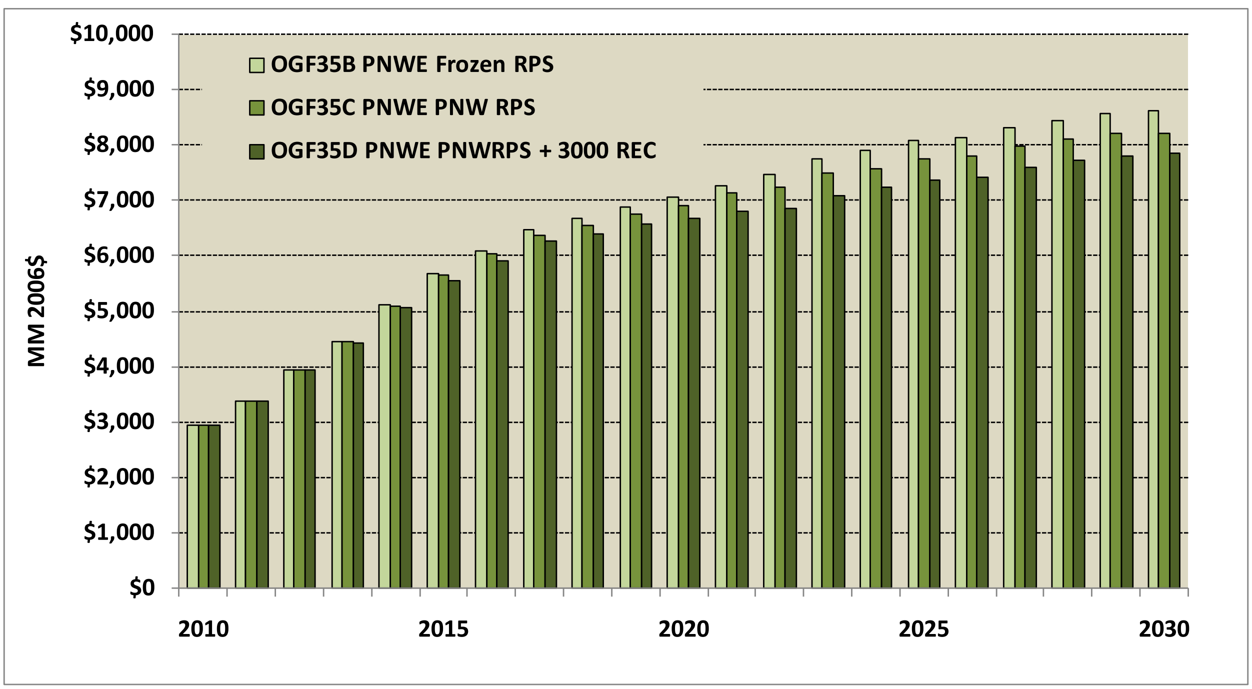
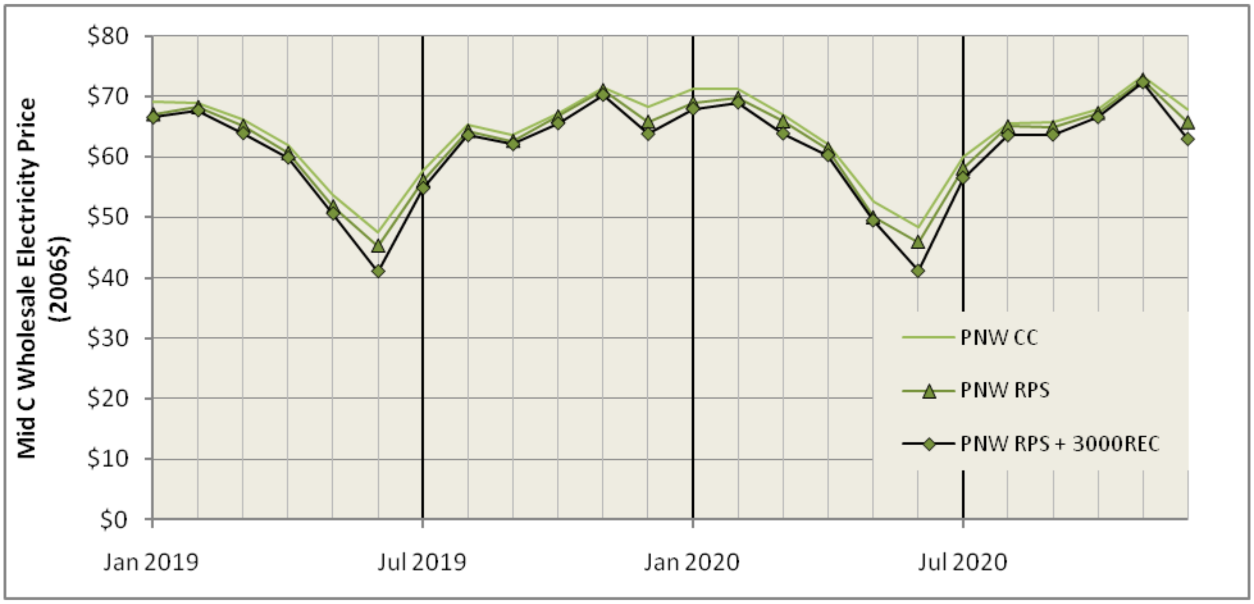


Figure 7: Energy value of Northwest hydropower resources



Not shown in Figures 6 and 7 is the value of hydropower and other firm resources associated with meeting peak demand. The bilateral transactions typical for the Northwest limit the ability to capture the value of resources to meet peak load. It is likely that the value of peaking capability from firm and flexible resources, including hydropower, will become increasingly significant as the penetration of non-firm resources and resources needing balancing reserves[21] increases. A liquid intra-hour market would better capture the value of flexible resources.

Figure 8: Forecast monthly Mid-Columbia spot prices for 2019 and 2020



Reducing the frequency and magnitude of excess energy events

A number of measures have been identified to help reduce the incidence of excess energy events on the power system. The measures introduced here are not analyzed in depth, nor are they exhaustive. Many of the short-term operational actions described in the Bonneville paper *Columbia River high water operations* are not included. The intent is to identify actions deserving further investigation. The Wind Integration Forum Steering Committee identified several action items to help integrate wind generation at its June 6, 2011 meeting. More extensive examination of measures to alleviate excess energy events will be undertaken in that venue.

Numerous actions are available to use available low-cost, low-carbon energy more productively. In terms of effects, these actions generally fall into the following categories: increasing demand (including access to neighboring markets); increasing diversity of renewable energy generation; increasing flexibility of incremental renewable energy projects; increasing system-storage capability; and improving renewable energy forecasting.

No one action is a panacea, and the cost, time to implement, and feasibility varies widely. In terms of feasibility, the actions can be broadly classified as policy-related and structural. Policy-related actions include amending state RPS to allow credit for hydropower substituted for curtailed wind. Policy-related actions can in theory be quickly implemented at relatively low

[21] Balancing reserve refers to the amount of generation needed to be held out of the market to respond to fluctuations in supply and demand for electric power in order to maintain power system reliability.

cost, however they may encounter political resistance or institutional inertia. Structural measures, on the other hand, such as expanding intertie transfer capability, are generally slow to implement and costly. Moreover, few of the structural measures, as individual actions, would contribute significantly to resolving the issues associated with surplus energy.

Measures reducing wind output peaks

The average annual capacity factor[22] of Columbia Basin wind projects is approximately 30 percent. The relatively low capacity factor of wind power leads to peak output events up to three times the average energy output. Developing higher capacity factor resources and resources with output that better coincides with load would reduce the probability of excess energy events for a given amount of RPS-qualifying energy. Several approaches to accomplishing this are described below. These are long-term measures that may require years to become effective. They might also reduce the impact of RPS development on the value of hydropower to the extent that the generation from RPS-qualifying resources could shift to seasons other than spring.

Encourage commercialization and development of higher capacity factor resources and resources with better load-resource coincidence: Biomass, geothermal, hydropower, and offshore wind power typically operate at a higher capacity factor than terrestrial wind power, and could help reduce peak output relative to average energy production. Solar photovoltaic facilities, on the other hand, have an even lower average capacity factor and a higher peak to average output ratio than terrestrial wind power. Solar resources, however, do not produce during low-load nighttime hours. Wave power, though having a low average capacity factor, has a strong winter peak that coincides with Northwest loads.

Expand the scope of RPS-qualifying resources to include additional high-capacity factor low-carbon resources: Washington's and Oregon's renewable portfolio standards are relatively inclusive, and opportunities to expand the set of qualifying resources with favorable operating characteristics are limited. Crediting energy efficiency on par with renewable energy would encourage developing an abundant, fixed-cost, zero-carbon resource with "output" nearly coincident with load. The Washington RPS excludes new hydropower as qualifying resources, except from irrigation pipes and canals that don't result in new diversions or impoundments. Expanding the definition of qualifying hydropower to include projects involving new water control structures outside of protected stream reaches might increase hydropower development. Though the development potential within the Northwest appears to be limited, British Columbia offers substantial undeveloped hydropower potential. Another avenue would be expanding qualifying cogeneration facilities. For example, extending eligibility to new or upgraded black liquor[23] cogeneration facilities could expand the availability of high-capacity factor qualifying resources at no increase in air emissions since the black liquor must be burned to recover the pulping chemicals whether or not power is produced.

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[22] The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

[23] Black liquor is a byproduct of the Kraft wood pulping process. It contains lignin residues, hemicellulose, and the inorganic chemicals used in the pulping process. The lignin and hemicellulose residues impart high energy content to black liquor, allowing it to be concentrated and burned in a chemical recovery boiler to recover the pulping chemicals for recycling.

Increase the geographic diversity of wind projects: Over 70 percent of committed Northwest wind generation is located in areas strongly influenced by Columbia Gorge winds. This concentration leads to peaks in wind output approaching full installed wind nameplate capacity, which contributes to the frequency and magnitude of excess energy events. Good quality wind resources are found elsewhere in the Northwest and in adjacent regions; however it would be necessary to strengthen or extend the transmission grid to tap large amounts of new resources in outlying areas. New long-distance high voltage transmission is expensive, requires many years to develop, and encounters public resistance. Moreover, because of the relatively low capacity factor of wind and the need to secure transmission transfer capability to accommodate a large proportion of the interconnected wind generation, transmission interconnection is more expensive on an energy basis for wind than for higher capacity factor resources. A recent study by the Columbia Grid and Northern Tier Transmission Group Wind Integration Study Team found that continued development near existing transmission, though incurring higher integration costs because of geographic concentration, is likely to be more cost-effective than constructing new long-distance transmission to tap remote wind resources. Exceptions to this may be remote development that could access existing transmission with the potential for relatively low-cost upgrades to increase transfer capability.

Measures reducing hydro output peaks

Several measures have been proposed that would reduce the volume of stream flow during over-generation events, and consequent spill levels. Because some of these measures would require pumping, they would also increase electrical loads during excess energy periods. These measures include on-stream pumped storage, increased irrigation withdrawals, and managed aquifer recharge. With the exception of increased irrigation withdrawals, these measures would require several years to implement and could require significant capital investment. These measures would reduce the severity of excess energy events and expand the use of low-cost, low-carbon hydro and wind energy.

Add on-stream pumped storage: The John W. Keys (Banks Lake) pumped-storage project is an on-stream project where water is pumped directly from Roosevelt Lake behind Grand Coulee Dam. At full load, this project draws about 600 MW and can pump about 18,000 cfs of water up to Banks Lake. Six of the 12 units are reversible, and can generate about 300 MW when discharging to Roosevelt Lake. The original and primary purpose of this plant is to supply water to the Columbia Basin Irrigation Project via Banks Lake. Peak flows at Grand Coulee during the June 2010 surplus energy episode were about 195,000 cfs, so the Banks Lake plant in pumping mode could have diverted about 9 percent of the peak in-stream flow during the June 2010 event while consuming about 9 percent of the full output of Grand Coulee. Moreover, this diversion would also reduce flow at all downstream projects. The combined effect is estimated to equal about 2,100 megawatts of load. Available storage at Banks Lake and its limited ability to discharge to the Columbia Basin Irrigation Project could ultimately limit the period of withdrawal. However, the active storage at Banks Lake represents about 480 hours of pumping at full load.

According to operational data received from BPA, the pumps at Grand Coulee typically came on for about nine hours during the night through the June 2010 event, but never at full load.

Operational constraints may limit the ability to operate the pumps over more hours, and maintenance may have limited the maximum capability level. The data also indicate that the pump/generators actually generated a total of almost 5,000 MWh during the first two weeks of June. It's possible that more could be done to optimize the operation of the pumps and pump/generator units during these events. BPA and the Bureau of Reclamation are considering upgrades to the Banks Lake facility to improve its reliability and flexibility.

As of October 2010, ten preliminary permits had been issued by FERC for proposed pumped storage sites in the Northwest and four more preliminary permit requests were pending. None of the 14 proposed projects would pump directly from in-stream sources, so they would not directly reduce in-stream flows, but they could present incremental load to the region. One, the proposed Banks Lake upgrade project, however, would use Banks Lake as a lower reservoir and could indirectly augment withdrawal by increasing the effective upper reservoir storage volume of the existing Keys pumped storage facility.

Increase irrigation withdrawals: The irrigation season in the Northwest runs from early April to mid-October. The season overlaps the April through June period when excess energy events most frequently occur. Increasing irrigation during this period will reduce in-stream flow. Electrical loads would increase to the extent pumping is used to lift irrigation water. The feasibility of this option would depend on crops, crop growing status, soil characteristics and moisture content, and other factors. Water withdrawal rights might complicate the feasibility of this measure, but it could be implemented quickly and without significant capital investment.

Develop recharge capability for depleted aquifers: Managed recharge of depleted aquifers could increase upstream water withdrawals and use surplus electricity. Groundwater pumping for irrigation has lowered groundwater levels in several areas of the Northwest, including the Odessa area of eastern Washington and the eastern Snake River Plain. A 1999 feasibility study of managed recharge of the eastern Snake River Plain aquifer suggests that recharge facilities would require little capital investment. They would be ponds located in natural depressions fed by controlled discharges from existing irrigation diversions. Issues include withdrawal rights, conflict with in-stream hydropower, fisheries and other in-stream environmental issues, and control of injection water quality. The eastern Snake study assumed using existing irrigation diversions and canals during the off season and considered the cost of constructing new facilities to be "prohibitive." Because recharge during the spring freshet season to mitigate surplus energy events would compete with existing irrigation system operation, expanding the existing irrigation conveyance system or constructing new conveyance facilities might be necessary.

Expand in-river storage: Raising high water reservoir elevations could add in-river storage. This has been proposed for at least one Mid-Columbia project. An assessment of this potential was not located for this paper.

Refine flood control management: Flood control operations specify maximum reservoir elevations to ensure sufficient vacated storage volumes to store flood waters. This can restrict the use of storage during high flows not approaching flood-level. Improved forecasting, control, and communication techniques may provide opportunities for refining flood control management and creating additional upstream storage during surplus energy events. Flood control operations are under review as part of the Columbia River Treaty negotiations.

Measures to curtail thermal output during excess energy events

During the height of the June 2010 excess energy episode, several hundred megawatts of thermal generation remained in operation in the BPA balancing authority area. Because this generation may have been required to maintain system stability or provide balancing reserves, it's uncertain if further reductions of thermal output were possible. Certain slow response generation facilities, such as the Columbia Generating Station, were held at minimum operating levels to serve unanticipated loads as the warm season approached. West wide, however, there may be opportunities to further reduce thermal operation during excess energy events. Plants can be retrofitted to reduce minimum operating levels and increase their ability to provide balancing reserves. Replacing slow response steam units with faster-responding units, such as gas turbines, can reduce the need to keep generators in operation to respond to unanticipated loads. Fast response units are also better-suited to provide balancing reserves.

Further curtailing thermal output would help use more low-cost, low-carbon hydro and wind energy, ease the severity of excess energy events, and facilitate faster dispatch. The process of replacing aging coal and gas-fired boiler-steam units is likely to lead to a more agile fleet of thermal units, but it will require many years and substantial capital investment to achieve this.

Measures increasing loads during high runoff periods

Measures that would increase loads during high runoff periods could reduce the incidence of excess energy events and expand use of available low-carbon hydro and wind energy. Strategies to increase loads during high runoff periods include fuel shifting, load shifting, producing alternative fuels using electricity, and increasing export capability.

Fuel shifting: Fuel shifting measures include electric vehicles, auxiliary electric boilers and hot water heaters, and dual-fuel boilers and hot water heaters. These measures would increase loads and could also store energy. This could help dampen price volatility, increase exports by facilitating transfers during off-peak periods, and possibly reduce the severity of excess energy events. Though additional load could marginally increase the need for RPS-qualifying energy[24], the proportion of hydro generation to load would diminish, reducing the frequency of excess energy events. With some exceptions, fuel-shifting options would require many years to achieve significant penetration and would require considerable capital investment.

Synthetic fuel or chemical production: Surplus electricity could be used to produce hydrogen or ammonia. Synthetic fuel production options would require many years to achieve significant penetration and would require considerable capital investment. Because of the magnitude of the capital investment, year-round operation would be required to achieve economic viability, and a facility could not depend solely on low-cost excess energy

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[24] For example, the spring 2011 curtailment events entailed limiting approximately 100,000 MWh of wind generation. If that energy were absorbed on systems subject to an RPS requirement of (say) 25%, the additional REC requirement would be 25,000 MWh, representing less than 0.5% of Northwest wind RECs generated in 2009.

Expand export transfer capability: Expanding out-of-region export capability could increase access to loads without increasing Northwest state RPS obligations. However, intertie transfer capability to California was not fully utilized during either the June 2010 or spring of 2011 surplus energy episodes. Reasons cited for this include line deratings (i.e., temporarily reduce line ratings usually due to maintenance issues), illiquid intertie transfer capability release markets, pricing differentials from California ISO congestion pricing (raising the cost of imports from the perspective of California utilities), and low wholesale prices in California due to high hydro conditions there. Addressing some of these issues could increase export capability relatively quickly and at relatively low cost. Over the longer term, and at much greater cost, expanding intertie transfer capability could be undertaken.

Current California RPS policy can affect both how much renewable energy gets constructed in the Northwest, and incentives for expanding intertie capability. Previous policies allowing REC-associated energy to be imported within the calendar year promoted development of resources in the Northwest to meet the California standards, but provided little incentive for California utilities to support expanded intertie transfer capability. California's April 2011 RPS revision appears to have significantly reduced economic incentives to locate RPS-qualifying resources in the Northwest. In-state development of RPS-qualifying resources within California could increase excess energy events within California itself, possibly compromising the value of increasing intertie transfer limits, depending on the daily and seasonal output of in-state RPS resources.

Energy storage: Energy storage facilities could shift surplus energy to periods when useful load may be available. Available technologies include pumped-storage hydropower, batteries, flow batteries, compressed air storage and, to a limited extent, demand response measures such as hot water management. These storage technologies are typically employed to shift energy between light and heavy load hours, and can become economically infeasible if cycled less frequently. Storage could expand the use of hydro and wind energy, and could ease the severity of excess energy events through load-shifting and more efficient use of intertie transfer capability to access California loads. Because springtime high-wind and runoff periods can last several days or weeks, storage technologies may not be economic due to the relatively large amounts of energy involved, and the relative infrequency of the events. Storage economics have not been favorable in the Northwest because of modest heavy load and light load price differentials. However, as wind generation becomes an ever larger fraction of the power supply, it is likely that the volatility of prices will become greater, increasing the value of storage. This effect illustrated with results of the Aurora studies shown in Figure 9[25]. This, plus a growing need for flexible resources, may improve the economic prospects of storage and flexible generation. Storage developed for other purposes may be able to provide some useful shifting of energy during excess energy events.

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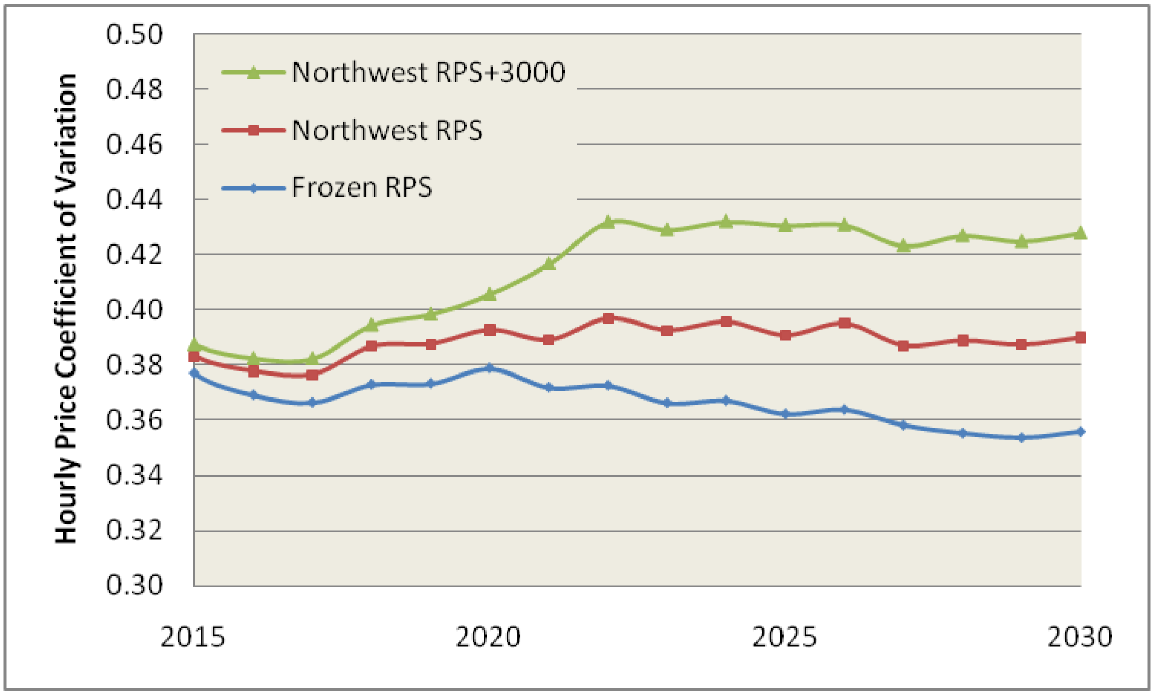
[25] The analysis captures expected fuel prices, loads, thermal outages, and wind generation. As such, it does not forecast the full range of price volatility. Figure 9 is indicative of the effect that wind adds to price volatility, but should not be taken as a forecast of expected volatility.

Figure 9: Price volatility affected by wind generation



Equity issues

Significant changes to any economic system are likely to result in participants who benefit and those who find themselves at a disadvantaged. It's common in utility rate making processes, for example, to assess how new capital expenditures affect different customer groups to ensure reasonable equity among ratepayers. Such equity issues can transcend utility boundaries, as when the addition of a baseload generator reduces the need for and value of higher variable-cost resources.

Equity issues have been raised with respect to the effects of reduced market prices, and more especially, about the relative tradeoffs between spilling wind energy or hydro energy. Below is a list of measures that may have the effect of reducing the level of cost shifts within the region. The Council and this paper take no position on the fairness or equitability of cost shifts.

Measures to displace wind during excess energy events

In its Interim Environmental Redispatch Policy (IERP)[26] BPA states that it will not pay purchasers to take federal hydropower and that it will curtail the operation of other resources, when dissolved gas levels exceed established limits and unloaded hydro turbines are available to reduce spill levels. Wind curtailments in the spring of 2011 were implemented under the IERP.

The IERP clearly identifies conditions under which BPA will curtail and the actions BPA will take prior to curtailment. Although the policy provides a clear allocation method, it results in

[26] BPA's Interim Environmental Redispatch and Negative Market Pricing Policies, May 2011, http://www.bpa.gov/corporate/pubs/RODS/2011/ERandNegativePricing_FinalROD_web.pdf.

some experiencing significantly greater economic harm than the benefit received by BPA. For example, in the spring 2011 event, BPA saved itself from paying negative market prices in the range of -$0.25 to -$10.00/MWh, but wind generators claimed financial losses ranging as high as the power purchase agreement prices plus production tax credits-- costs that might have been in the range of $100/MWh. This disparity in benefits to BPA and losses to generators fuels the current controversy and represents an opportunity for more efficient means of achieving the same results. For example, it has been suggested that within specified limits, BPA could enter into negative price sales but recover its costs from wind generators. Several other options for reducing the financial disincentive for wind plant operators to curtail operation during over-generation have also been proposed. These include crediting substitute hydropower as an RPS and production tax credit qualifying resource; substituting fixed payment for variable payment incentives; and hosting competitive markets (auctions) to pay wind operators to curtail.

Qualify substitute hydropower as a RPS/PTC resource: Wind operators receive value in the form of RECs for producing qualifying RPS energy. Many also receive revenues from the federal production tax credit. Because these revenues depend on energy production, the net variable cost of operation is negative. If the wind plant owner received an equivalent production tax credit and RPS credit during defined conditions where hydropower was substituted for wind power, wind power would then carry a slight positive variable cost. If this variable cost were higher than the variable cost of hydropower, wind operators would curtail in favor of hydro. Because the “true” variable cost of wind plant operation is low, it may also be necessary to levy a portion of its integration costs as variable to ensure that the dispatch cost of wind is higher than hydro. Reducing the costs to displace wind would help reduce excess energy events and their effect on market prices, as well as address dissolved gas problems. However, regulatory and existing wind power purchase contracts prohibiting substitute energy could limit this action.

Implementing this concept would require changes to federal production tax credit statutes and to California, Oregon, and Washington RPS statutes. Though these changes could conceivably be enacted quickly, the political challenges of re-opening incentive legislation may make it difficult to quickly implement these changes.

Substitute fixed for variable financial incentives: Many early renewable resource incentives were fixed, including front-end grants and investment tax credits. Because some of the resulting projects performed poorly, and to encourage plant owners to maximize energy production, fixed incentives were largely abandoned for the production tax credit, a variable payment based on energy production. State renewable portfolio standards also create variable incentives, since the premium paid for qualifying energy is based on energy production. Some fixed incentives remain, such as the sales tax credit that Washington provides for certain renewable energy equipment, the federal investment tax credits for solar and certain other renewable energy projects, the Oregon business energy tax credit, Energy Trust of Oregon grants, and federal construction loan guarantees. Moreover, Section 1603 of the 2009 American Recovery and Reinvestment Act allows wind project developers to forego tax credits for an up-front grant equal to 30 percent of the capital investment. Projects completed during 2009 and 2010, or under construction as of the end of 2010, are currently eligible for this grant.[27] The grant option has been very popular and extension would likely result in the majority of new projects opting for the grant. Extending the grant option, combined with the gradual expiration of the production tax credit for existing projects could, over time, eliminate the production tax credit as a negative price signal.

Compensate wind plant owners for losses due to curtailment: A balancing authority could purchase curtailments or curtailment rights from wind operators. Revenues to cover the cost of compensation would have to be secured. One approach is for the balancing authority to secure an inventory of curtailment options to cover anticipated needs. Revenues to finance acquiring the options could be rolled into wind integration costs. This represents a market approach, targeting the least costly wind projects for curtailment first and spreading the resulting costs among all wind plants. The cost to wind plant owners could then be passed to wind energy customers.

Measures augmenting energy dump capability

Measures that augment energy dump capability would increase the ability to release surplus energy in an environmentally acceptable manner, reducing the need to displace wind or hydro. Although these measures effectively waste potentially useful low-cost, low-carbon energy, the effect is similar to the historical spilling of water at the dams prior to establishing total dissolved gas (TDG) limits.

Improved dissolved gas abatement: A variety of structural and operational measures for reducing dissolved gas levels have been proposed, including spillway flow deflectors, raised stilling basins, raised tailrace channels, additional spillway bays, tailrace/stilling basin separation walls, submerged conduits, baffled spillways, side channel spillways, pool and weir channels, and submerged spillway gates. The most feasible structural alternatives, primarily spillway flow deflectors, have been installed at all Lower Snake and Lower Columbia Corps projects with the exception of The Dalles,[28] increasing gas-limited spill capacity.

Relaxed dissolved gas standards: Currently, exceeding TDG water quality standards is only permitted for spill for fish passage purposes through the waiver process in Oregon and the exemption built into Washington's water quality standards. An effort to obtain a similar waiver or statutory provision that pushes allowable spill even higher during periods of excess energy would probably not be feasible since water quality standards must be stringent enough to protect all the uses of the Columbia and Snake rivers, and aquatic life is generally the most sensitive.

While scientists and policymakers may not necessarily agree on the specific point where the risks of gas bubble trauma to aquatic life outweigh the benefits of spill for juvenile fish, it's generally agreed that there is some level at which the risks of gas bubble trauma outweigh the benefits of assisting migrating smolts. Given that excess energy events are likely to occur in June when the TDG 115/120 percent waiver cap is in effect, getting Oregon's Environmental Quality

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[27] The Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 extended the eligibility to December 31, 2011.

[28] Stilling basin bathymetry at The Dalles would compromise the effectiveness of spillway flow deflectors.

Commission or Washington's Department of Ecology to go even further, potentially increasing risk to salmon and other aquatic life, in order to deal with a surplus energy event may be a challenging task. Past review processes to obtain the waivers have proven both lengthy and contentious. Moreover, the EPA's review of any changes to state water quality standards that would allow TDG standards to be exceeded during times of excess energy would likely take a long time, and the outcome is uncertain.

One other possibility may be to create an exemption in the state water quality laws for excess energy events similar to what is provided for 7Q10 flood flows.[29] It may be difficult if not impossible to get the states to adopt, and EPA to approve, an exception to state water quality standards given the existing restrictions on spill required to protect aquatic life.

Resistive Load Banks: Resistive load banks are devices designed to absorb electric energy, providing a load with desirable characteristics (unity power factor). Load banks are in common use for generator testing. The Northwest's 1,400 MW Chief Joseph substation "dynamic brake" is an example of a load bank used to maintain power system stability. This device may have no practical application though, since it is designed to operate for less than a second at a time.

While BPA's dynamic brake's limitation makes it unsuitable for absorbing large amounts of energy, it demonstrates the scale feasibility of load banks. Megawatt-scale load banks designed for continuous service are commercially available. A quick internet search found a handful of providers of megawatt-scale units.30 The cost for the units, absent installation and interconnection, appears to range from about $20-40/kW. Spill rates during the June event were approximately 875 MW at Grand Coulee and 325 MW at Chief Joseph. If the total 1,200 MW were matched by load banks, the equipment cost of accommodating the generation and avoiding spill would be on the order of $25-50 million. Additional costs for land, installation, and interconnection could increase this two to three times.

Although finding more constructive uses for the energy would be desirable, load banks could expand zero price options for generation, provide an alternative to spill that would otherwise raise nitrogen levels, and provide additional system reliability to the balancing area to reduce the risk of over-frequency events. For example, total wind generation was at about 200 MW on May 18, 2011 when BPA first curtailed wind generation under its new policy. The curtailment was not sufficient to maintain gas levels below limits. Load bank technology could have allowed BPA to reduce spill to levels consistent with the gas caps.

Conclusion and next steps

The analysis conducted by Council staff suggests that the likelihood of excess energy events has increased significantly since 2008 but will not increase significantly from current levels absent significant pressures to develop renewable resources for export. The analysis also shows some downward price pressure due to increasing amounts of low variable-cost renewable resources on the Northwest power system. Measures to reduce the likelihood of excess energy events exist, although there doesn't appear to be a simple, inexpensive fix. Economic dislocations due to

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[29] 7Q10 is the average peak annual flow for seven consecutive days that has a recurrence interval of 10 years.
[30] Avtron, Mosebach Manufacturing, Power House Manufacturing, Sephco, and Simplx.

shifts in costs and spill exist, and measures were identified that may reduce the severity of the dislocations.

The analysis presented here is clearly an initial first step. The Council staff, through the Resource Adequacy Forum and the Wind Integration Forum will continue to study and refine the analysis on the effects of wind on hydro operations and spill.

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