61.03 ~~60.4~~ Sally T. Jones

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

January 3, 2011 | document 2011-01

Share Like

Comment on this paper

Send comments by
Monday, January 31, 2011 to:

Mark Walker
Public Affairs Division Director
Northwest Power & Conservation Council
851 SW 6th Avenue, Suite 1100
Portland, Oregon 97204-1348
or email

read full document > (310k)

The Council seeks comments on the paper *Effects of an Increasing Surplus of Energy Generating Capability in the Pacific Northwest.* This paper and the accompanying analysis were prepared in response to Action GEN-10b of the Sixth Northwest Conservation and Electric Power Plan. Action GEN-10b calls for the Council to assess the potential extent of the future unbundled REC market, the resulting benefits and costs, and actions needed to remedy significant impacts.

A consequence of the rapid development of Northwest wind projects to serve regional and California renewable portfolio standards is an increasing surplus of low variable cost energy generating capability. This surplus appears to be contributing to lower electricity market prices, reduction in the value of surplus hydropower energy, and an increasing frequency and severity of excess energy events, such as occurred during June 2010.

The purpose of this paper is to assess the significance of these effects and to stimulate discussion of possible mitigating measures. The paper includes a forecast of the effects of wind resource development on the frequency of excess energy events, on market prices and on resource value. The paper also identifies measures that could help resolve adverse effects of a surplus of low-cost energy.

Specifically, the Council is seeking comments on the following:

What additional analysis should be undertaken regarding these issues?

What additional issues, if any, should be addressed?

What additional assessment of mitigating measures should be undertaken?

Your feedback and suggestions will help to further inform this discussion. Comments are requested by close of business on Monday, January 31st.

Sincerely,

Mark Walker, Public Affairs Division Director

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

DRAFT

Council Document 2011-01

SUMMARY

The Northwest is experiencing an increasing surplus[1] of energy generating capability. Because the resources contributing to the surplus consist largely of low variable-cost resources like wind, which must operate to provide qualifying energy for state renewable portfolio standards (RPS), the surplus will tend to reduce average electricity market prices and increase the frequency and severity of excess energy events.[2] Stagnant and declining loads due to the economic recession have contributed to the surplus in the near-term. Over the longer term, resource development to meet Northwest state RPS, and the development of Northwest resources to serve the California RPS, are the principal contributors to this surplus.

While loads are expected to recover over the next several years, RPS resource development is expected to continue in advance of load growth until the ultimate Northwest RPS targets are met in 2020 through 2025. The extent of additional Northwest wind power development to serve the California RPS will depend on currently unresolved California RPS policy and the availability and cost of competing resources, especially solar. Retiring Boardman and other thermal units could offset the tendency of the surplus to reduce average market prices, but it is unlikely to significantly affect the frequency and severity of excess energy events and accompanying low or negative energy prices.

[1] Throughout this paper, the term "surplus" is used to refer to the growth of energy generating capacity in excess of reliability requirements.
[2] The term "excess energy events" refers to periods of high water, low loads, and high wind that can lead to difficulty in maintaining acceptable levels of dissolved gas.

Concerns regarding the use of unbundled renewable energy credits (RECs[3]) from Northwest wind projects to serve California RPS led to inclusion of Action GEN-10b in the Sixth Northwest Conservation and Electric Power Plan. Action GEN-10b calls for the Council to assess the potential extent of the future unbundled REC market, the resulting benefits and costs, and actions needed to remedy significant impacts. This paper describes a forecast of the effects of RPS resource development on the frequency of excess energy events, and on market prices and resource value. The paper also identifies measures that could help resolve issues stemming from the growing surplus. The focus is on longer-term strategic measures rather than shorter-term system operational measures. The latter are discussed in the Bonneville Power Administration (BPA) Columbia River high water operations paper.[4]

The analyses of this paper were carried out using an economic model of the power system with a simplified representation of hydropower system operation. The results should be viewed as relative, rather than as an absolute indication of frequency and magnitude. The Council's Resource Adequacy Forum is working with the Pacific Northwest Utilities Conference Committee (PNUCC), 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 the following:

- Development of resources to serve Northwest state RPS tends to increase the frequency of excess energy events and accompanying low electricity market prices, until final RPS targets are met. After meeting the final RPS penetration targets, in the early to mid-2020s, the frequency of excess energy events is expected to slowly decline.

- Additional wind development for export of unbundled RECs is likely to further increase the frequency of excess energy events.

- The probability of excess energy events increases during good water years and declines during poor water years. This analysis also suggests that the severity of excess energy events is less sensitive to moderate variation around average water conditions. As demonstrated in June 2010, unusual runoff patterns can create excess energy conditions even in average water years.

- Aggressive RPS targets and financial incentives tend to result in the growth rate of RPS-qualifying energy production exceeding load growth. This will drive down the average market price of non-RPS qualifying electricity.

- The average impact of depressed market prices on the energy value of Northwest generating capacity will be moderate, but the value of hydropower will be disproportionally reduced.

---

[3] Renewable energy credits (RECs) represent the environmental and renewable attributes of renewable energy 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, interest in meeting RPS requirements with partially or fully unbundled RECs has increased.

[4] Bonneville Power Administration. *Columbia River high water operations (June 1-14 2010)*. September 2010

- Measures are available to reduce the frequency of excess energy events, to alleviate the economic and operational issues associated with excess energy events, to reduce energy market impacts, and to more productively use available low-cost, low-carbon energy. Policy-related measures are generally low-cost and quickly effective, but may be politically difficult to implement. Structural measures tend to be capital-intensive, of limited effectiveness, and slow to implement.

BACKGROUND

Historically, the combination of high springtime runoff and low electrical loads has led to episodes of excess energy in the Pacific Northwest. Typically, these episodes occur during the spring runoff when loads are low and total dissolved gas water quality standards constrain spill, thereby limiting the ability to reduce hydropower generation levels.

The dissolved gas content of stream flow is 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 rivers and some tributary dams as water plunges over the spillway into the stilling basins. At high levels, dissolved gas can be harmful for fish and other aquatic life by causing gas bubble trauma; so voluntary spill is limited by gas super saturation "gas caps" required under the federal Clean Water Act.

Hydro-rich utilities have aggressively marketed 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 thermal resources is $10 - $20 per megawatt hour, single-digit hydropower offers have been sufficient to displace thermal generation both in the Northwest and in California. Load would shift to hydropower, thus minimizing involuntary spill.

Large-scale wind development adds a new variable to this equation. Wind operators receive value in the form of renewable energy credits (REC) for producing qualifying energy. Variable (production-related) financial incentives and RECs lower the cost of wind plant operation to negative values. Published data is sketchy, but the market value of renewable energy credits appears to be $20 to $35 per megawatt-hour (MWh). In addition, many wind projects receive the federal renewable production tax credit, currently about $22 per MWh.[5] Though wind projects typically have a small positive variable operating cost, the RPS value and the production tax credit, if present, can create a negative variable cost, -$15/MWh, or less. Owners of PURPA Qualifying Facilities may see even greater losses from curtailment, up to the avoided cost of new generating facilities. These are economic disincentives for wind project operators to curtail operation in favor of hydropower during excess energy events, resulting in a potential conflict with total dissolved gas standards.

[5] 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, most 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.

EFFECTS OF AN ENERGY SURPLUS

Large-scale wind development in the Northwest has been driven by state renewable portfolio standards (RPS) and various federal and state financial incentives. Twenty-seven states, including Montana, Oregon, Washington, and California, have adopted renewable portfolio standards, which mandate that a specified percentage of retail sales be met using electricity from certain qualifying sources. These sources may include various renewable energy resources, new technologies and in several states, energy efficiency. Because the objective is to encourage development of new capacity, energy from existing renewable resources, including hydropower, is largely excluded. Penetration targets vary by the type and size of utility, and increase by prescribed schedule until ultimate penetration levels are achieved.[6] Penetration levels remain constant thereafter as a percentage of loads. 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.

Several characteristics of RPS resource development tend to lower energy market prices. First, RPS resources have, and at expected rates of load growth, are likely to continue to be developed in advance of load growth until the final RPS targets are achieved. Second, RPS resources must operate to produce the qualifying energy. Finally, the variable costs of resource operation are typically low. Developing renewable energy to export unbundled RECs will further depress energy prices since the associated energy enters the Northwest market. This can lead to the loss of revenue on the part of utilities holding an abundance of non-RPS resources. Resource-short utilities, on the other hand, may benefit from lower market prices.

Adding low variable-cost resources in advance of load growth can lead to an increasing frequency of excess energy events. Excess energy events are manifested by low market prices, as asking prices are lowered in an effort to market the excess. Periods of low market prices, indicating the availability of large amounts of energy relative to load, occur during nearly every spring runoff period. As shown in Figure 1, episodes of zero or negative market prices have occurred in six of the past 11 runoff periods, and appear to be increasing in frequency in recent years. Though the increased frequency of zero or negative price episodes corresponds with the rapid growth in Northwest wind capacity, other factors are at play, including water conditions, runoff patterns and, since 2008, declining loads due to the economic recession.

[6] 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 - 20% by 2020. RPS provisions are complex and vary by state. Detailed information concerning the RPS of individual states is provided in the Database of State Incentives for Renewables and Efficiency (DSIRE), www.dsireusa.org.

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

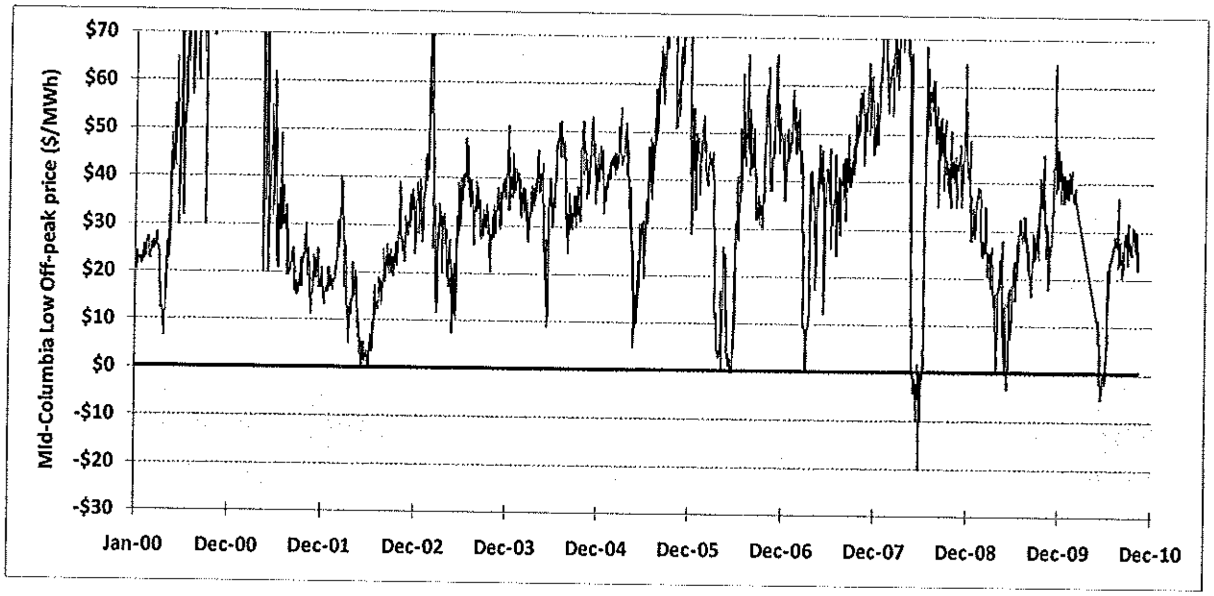


Figure 2 provides a closer look at the June 2010 episode. Bonneville balancing authority loads and resources are plotted on the left axis for the first half of June 2010. Bonneville load, consisting of native load plus exports net of imports is shown as the shaded area. Load varied between 8,300 and 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.[7] 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 resulting from any unexpected warm spell.

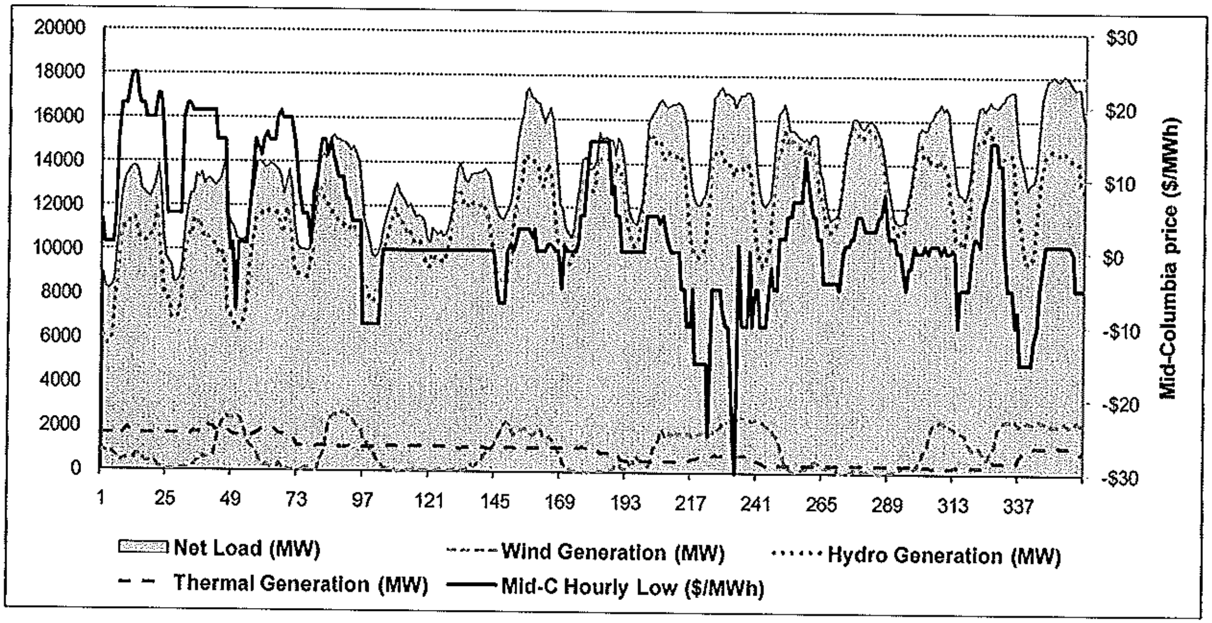
Mid-Columbia market prices are plotted on the right axis. Note that the zero point of the right axis lies halfway up the axis. Most of the negative price excursions coincide with low load, low hydro, and high wind hours. Exceptions appear, including the extreme low of -$30 during hour 233.[8] This low, 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.

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

[7] 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.

[8] 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.

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



FORECAST EFFECTS OF A GROWING SURPLUS OF LOW VARIABLE COST RESOURCES

The frequency of excess energy events, and resulting effects on wholesale energy prices and resource values were forecast for three cases of future resource development:

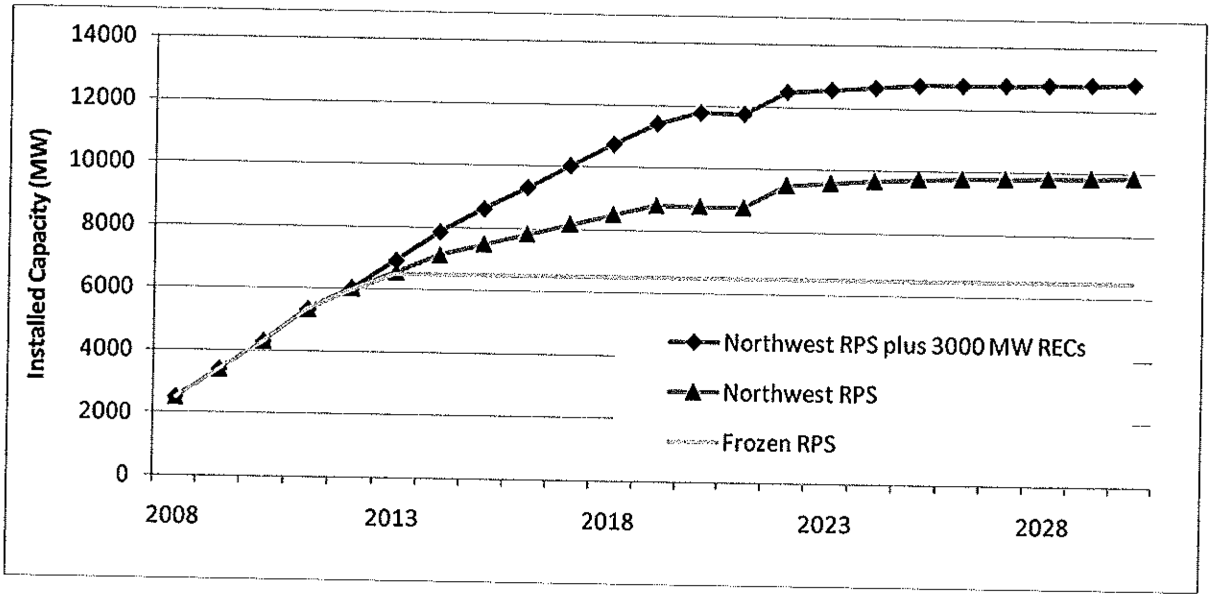
Frozen RPS: This case assumes no further development of qualifying resources to meet the RPS obligations of Northwest utilities, or for the purpose of supplying RECs to meet California RPS, beyond currently committed resources. Some committed resource development continues through 2012.

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

Northwest RPS plus 3000 REC: This case assumes continued development of a mix of qualifying resources as needed to fully meet the RPS obligations of Northwest utilities, plus development of an additional 3,000 MW of wind capacity for export to California in the form of unbundled RECs. The capacity to serve California is developed at the rate of 375 MW per year from 2013 through 2020.

Figure 3 illustrates the build-out of Northwest wind capacity for the three cases. The peak penetration of wind 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 3000 REC*: 38 percent.

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

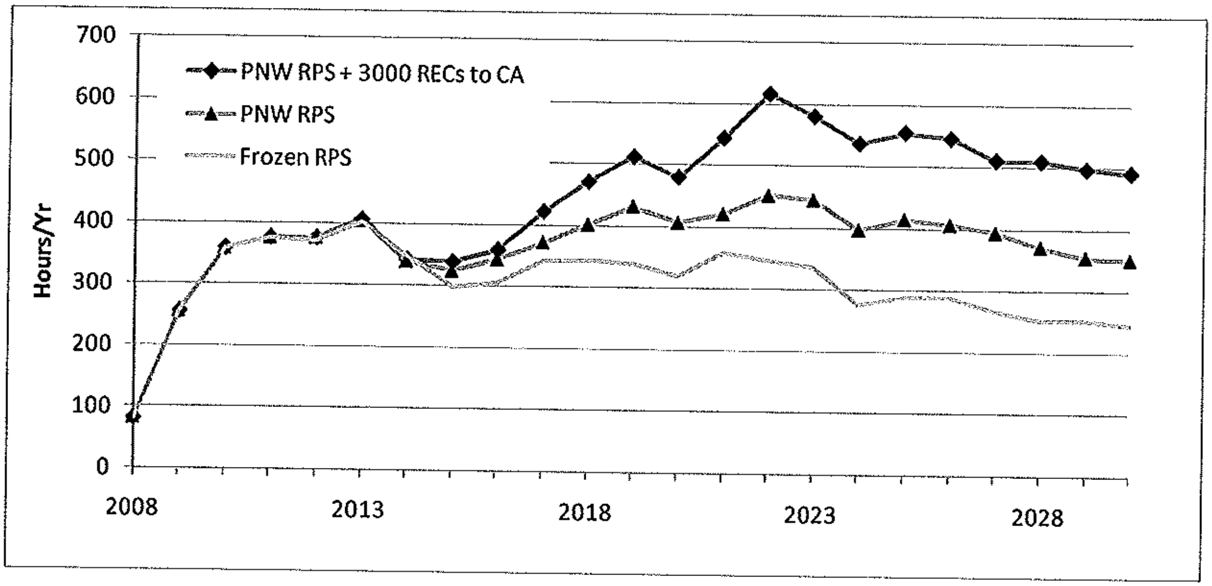


The analysis was performed using the AURORA^{xmpTM} Electric Market Model, using the input data, capacity expansion schedules and principal assumptions of the final wholesale power price forecast of the Sixth Power Plan. Key assumptions included average water conditions, the Council's medium case forecast 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 capacity forecast (absent RPS resources in the *Frozen RPS* case) used for the final wholesale power price forecast of the Sixth Power Plan. This capacity forecast includes retiring Boardman and several other coal and older natural gas combined-cycle units between 2016 and 2022.

Frequency of Excess Energy Events

Annual hours during which regulated Pacific Northwest hydropower output is at or below minimum levels was used as an index of the expected frequency of excess energy events. The forecast annual frequency of excess energy events is shown in Figure 4 for the three cases.

Figure 4: Forecast annual hours of excess energy



Regional load growth and resource additions through 2012 are the same for all cases, hence the frequency of excess energy events is identical through 2012. In all cases, the frequency of potential excess energy events grows rapidly from 2008 through 2010, and then continues at a slower rate through 2013. The rapid expansion of wind capacity and stagnant load growth extends from 2008 through 2010. Committed wind development declines in 2011 and 2012 and loads are forecast to recover from the recession. These factors probably lead to the declining rate of increase 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.

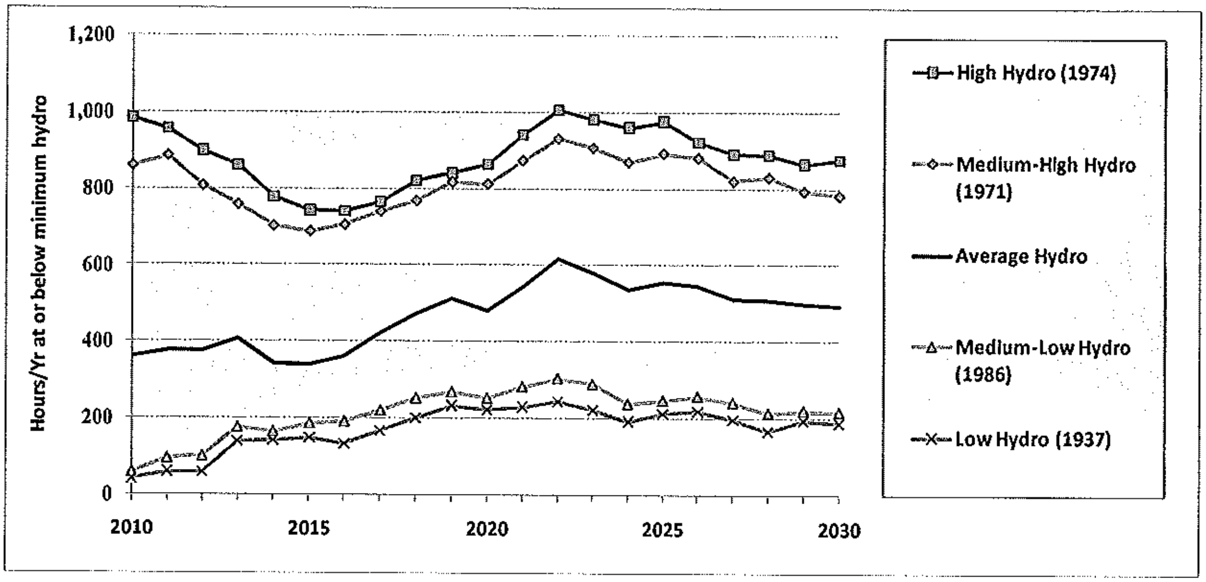
The resource mix of the cases diverges in 2015, as do the frequency of excess energy events. In the *Frozen RPS* case, excess energy events decline through the remainder of the forecast period. This is expected, since new firm resources are added only as needed to accommodate load growth, variable wind and hydropower represent a diminishing share of all capacity, and the production tax credits expire for individual plants following 10 years of operation[9]. Wind penetration continues to increase through 2025 in the *Northwest RPS* case. Excess energy events peak in 2022 at 26 percent greater frequency than 2010. Thereafter, the frequency of excess energy 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 3000 REC* case follows a similar pattern but with a more rapid increase, peaking in 2022 at a 72 percent increase over 2010 levels.

The probability of excess energy events should be lower during poor water years and higher in good water years. Sensitivity to water conditions was tested for the *Northwest RPS plus 3000 RECs* case with a range of historical water years from low to high water conditions. Years with seasonal profiles representing the average were selected. The effect on expected instances of excess energy is shown in Figure 5. As expected, the frequency of excess energy events declines

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

during poor water years and increases during years of abundant water. Modeling results not shown in Figure 5 suggest that the frequency of excess energy events is less sensitive to mid-range water conditions, though more testing is required to confirm this observation.

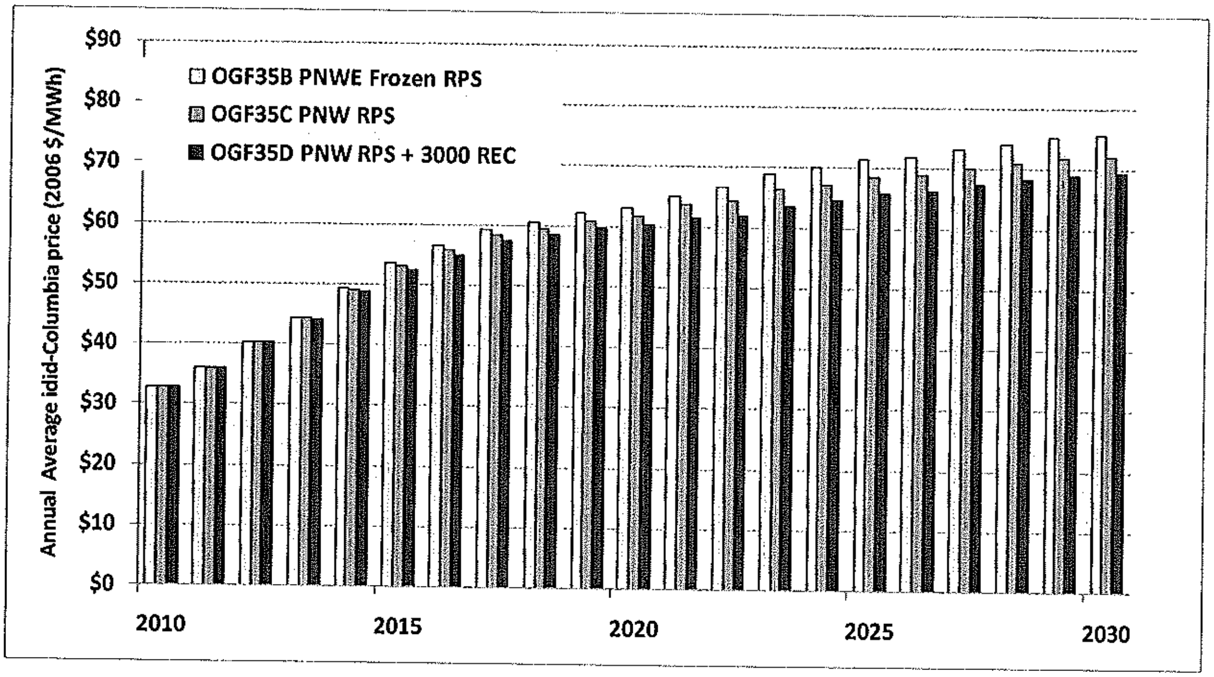
Figure 5: Frequency of excess energy hours under a range of water conditions



Market Price Effects

Forecast average annual Mid-Columbia prices, in constant 2006 dollars, are shown in Figure 6 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. By 2020, the average annual average 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 + 3000 REC* case is 4 percent below the *Frozen RPS* case. By 2030, the differences have grown to 5 percent and 8 percent, respectively.

Figure 6: Forecast average annual Mid-Columbia spot prices



The energy value of a resource is the difference between energy revenue and the variable cost of resource operation. As shown in Figure 7, 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 3000 REC* cases appear to be offset by the added volume of low-cost electricity from the additional capacity 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 3000 REC* case, as shown in Figure 8. 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. Because the frequency of low prices increases during the spring runoff when large quantities of surplus hydropower are typically marketed, the value of hydropower is more sensitive to surplus energy events.

Figure 7: Energy value of all Northwest resources

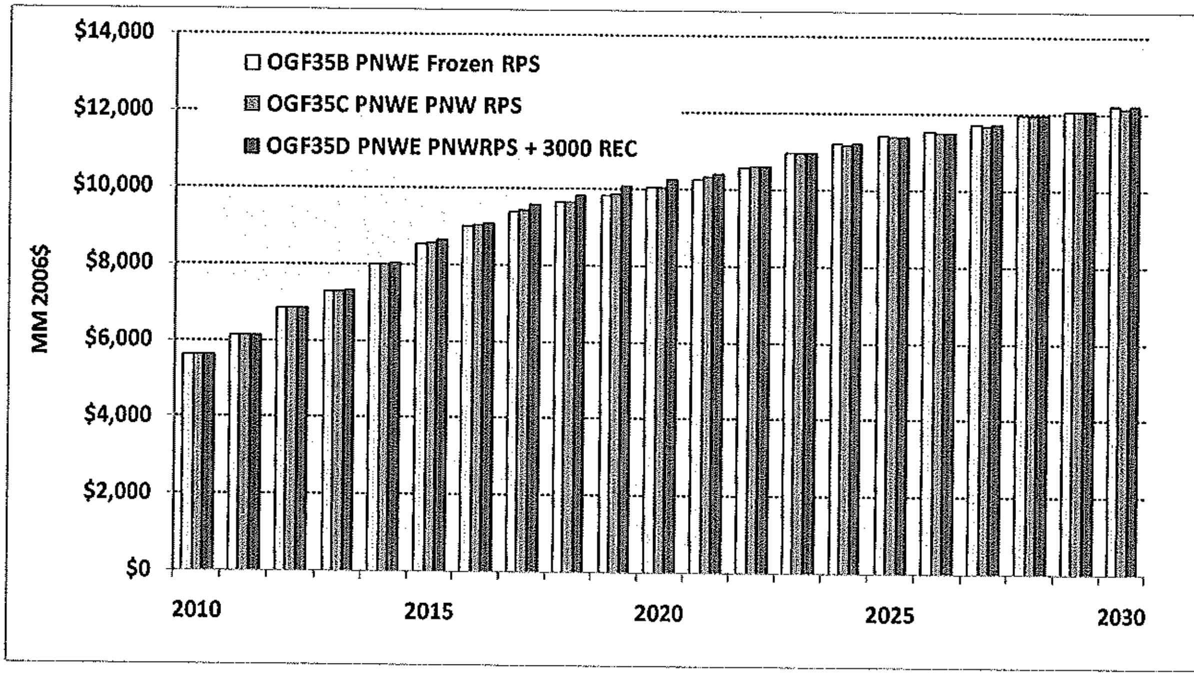
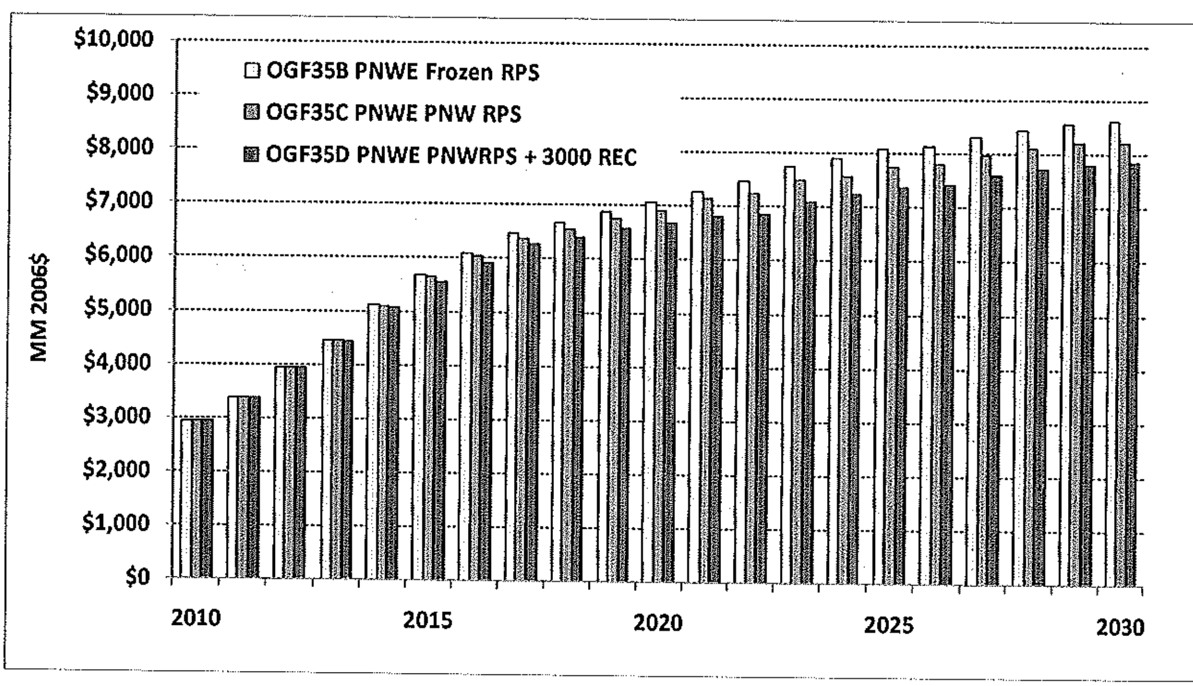


Figure 8: Energy value of Northwest hydropower resources



Not shown in Figures 7 and 8 is the capacity value of hydropower and other firm resources. The bilateral capacity transactions typical for the Northwest limit the ability to capture resource capacity value. It is likely that the capacity value of firm and flexible resources, including hydropower, will become increasingly significant as the penetration of non-firm resources and resources needing balancing reserves increases. A liquid capacity market would facilitate capture of resource capacity value.

MITIGATING MEASURES

This section introduces measures that could help mitigate the issues presented by a growing energy surplus. These are not analyzed in depth, nor are they exhaustive. 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.

Numerous actions are available to alleviate the economic and operational issues associated with excess energy events, to reduce energy market impacts, and to more productively use available low-cost, low-carbon energy. In terms of effects, these actions generally fall into the following categories: curtailing wind output during excess energy events, reducing wind output peaks, reducing hydro output peaks, increasing loads during excess energy events, augmenting energy dump capability, and reducing thermal output during excess energy events. 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 those such as amending state RPS to allow credit for hydropower substituted for curtailed wind. Policy-related actions can in theory be quickly implemented at relatively low cost, however they may encounter political resistance. Structural measures, on the other hand, such as expanding intertie capacity, 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 Facilitating Displacement of Wind during Excess Energy Events

Bonneville has stated[10] that it will not pay purchasers to take federal hydropower and that it will curtail the operation of other resources, if necessary, to maintain system reliability and avoid violating environmental standards during excess energy events. Because of the complexity of circumstances associated with excess energy events, the variety of operational measures available to help resolve the conflict between hydropower and wind generation, and the prospect of economic loss to wind operators, it is prudent for Bonneville, or any other balancing authority (BA) asserting this policy, to clearly identify the conditions under which it will curtail, and the actions it will take prior to curtailment. In fact, Bonneville has proposed to do this. This policy, however, does not resolve the economic concerns associated with this matter, since curtailments will not leave wind operators economically whole, unless their power sales agreements are negotiated with an expectation of occasional curtailment. Several options for reducing the financial disincentive for wind plant operators to curtail operation during over-generation events are available. These include crediting substitute hydropower as a RPS and PTC qualifying resource; substituting fixed payment for variable payment incentives and compensating wind operators for curtailment losses.

[10] Bonneville Power Administration. *Statement on Environmental Redispatch and Negative Pricing*. December 3, 2010.

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 are a function of 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 under which hydropower was substituted for wind power to maintain environmental requirements, wind power would then carry a slight positive variable cost. If the resulting variable cost of wind were higher than the variable cost of hydropower, wind operators would curtail in advance 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 that of hydro. Reducing costs associated with displacing wind would help alleviate excess energy events and reduce downward pressure on market prices while potentially reducing dissolved gas problems. The efficacy of this action may be limited by existing wind power purchase contracts prohibiting substitute energy, and by PURPA contracts.

Implementing this concept would require changes to federal production tax credit statutes and to California, Oregon, and Washington RPS statutes. Though in theory these changes could 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 American Recovery and Reinvestment Act (ARRA) of 2009 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.[11] 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 compensate wind operators for losses from curtailment; however, revenue 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 curtailment needs. Revenues to finance acquiring the options could be rolled into wind integration costs. This approach would leave

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

individual wind plant owners economically whole by spreading the cost of lost incentives among all wind plants. The cost to wind plant owners could then be passed to wind energy customers.

Measures Reducing Wind Output Peaks

The average annual capacity factor of Columbia Basin wind projects is approximately 28 to 32 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 better coinciding 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, requiring years to become effective. They might also reduce the impact of RPS development on the value of hydropower to the extent that the peak resource output would 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 Renewable Energy Standard (RES) and Oregon's Renewable Portfolio Standard are relatively inclusive, and opportunities for expanding 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 RES prohibits new hydropower, except from irrigation pipes and canals that do not 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 potential. Though such potential within the U.S. Northwest appears to be limited, British Columbia offers substantial undeveloped hydropower potential. Another avenue would be expanding qualifying cogeneration capacity. For example, Washington's RES currently prohibits energy from cogeneration facilities fueled by black liquor.[12] Expanding eligibility to new or upgraded black liquor 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 from the resulting energy.

[12] Black liquor is the spent cooling liquor of the Kraft wood pulping process. It contains lignin residues, hemicellulose, and the inorganic chemicals used in 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 geographical diversity of wind projects: Over 70 percent of committed Northwest wind capacity is located in areas strongly influenced by Columbia Gorge winds. This concentration leads to peaks in wind output approaching full installed wind 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 capacity to accommodate a large proportion of the interconnected wind capacity, transmission interconnection is more expensive for wind than for higher capacity factor resources. A recent study by the Columbia Grid and Northern Tier Transmission Group Wind Integration Study Team (WIST) 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 of transfer capacity.

Measures Reducing Hydro Output Peaks

Several measures have been proposed that would reduce the volume of stream flow during over-generation events. These measures could reduce spill. Because some of these measures would require pumping, they would also increase electrical loads during surplus 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, expand the productive use of low-cost, low-carbon hydro and wind energy and help curtail negative electricity market prices.

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 Keys plant in pumping mode could divert 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, diversion above Grand Coulee would reduce flow at all downstream projects. The combined effect is estimated to be equivalent to about 2,100 megawatts of load. Banks Lake storage capacity and ability to discharge to the Columbia Basin Irrigation Project could ultimately limit the period of withdrawal; however, the active storage capacity of Banks Lake represents about 480 hours of pumping at full capacity.

According to operational data received from BPA, the pumps at Grand Coulee typically came on for about nine hours during the night through this period, but never at full capability. 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 is possible that more could be done to optimize the operation of the pumps and pump/generator units during these events.

As of October 2010, 10 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. One, the proposed Banks Lake project, however, would use Banks Lake as a lower reservoir and could indirectly augment withdrawal by increasing the effective upper reservoir capacity 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 during which excess energy events most frequently occur. Increasing irrigation withdrawal rates 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. This measure 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 productively employ surplus electrical energy. Groundwater pumping for irrigation has resulted in declining 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 relatively little capital investment would be required for the recharge facilities themselves - they would essentially consist of 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 use of 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 irrigation use of the existing diversion and conveyance structures, a scheme intended partly to alleviate surplus energy events would require expanding the capacity of the existing irrigation conveyance system or constructing new conveyance facilities.

Expand in-river storage: Additional in-river storage could be gained by raising high water reservoir elevations. 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 require reserving storage capacity to accommodate flood flows. This can restrict storage capacity 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 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 productive 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. These measures could reduce the incidence and severity of excess energy events, expand the productive use of low-cost, low-carbon hydro and wind energy and help curtail negative electricity market prices.

Fuel shifting: Fuel shifting measures include electric vehicles, auxiliary electric boilers, hot water heaters, and dual-fuel boilers and hot water heaters. These examples of fuel shifting would increase loads and could also provide energy storage. This could help dampen price volatility, increase the export potential by facilitating transfers during off-peak periods, and possibly reduce the severity of excess energy events. Though additional load would increase the need for RPS-qualifying energy, the proportion of hydro capacity 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 surplus energy

Expand export capacity: Expanding out-of-region export capacity could increase loads without increasing Northwest state RPS obligations. Intertie capacity to California was not fully utilized during the June 2010 surplus energy episode. Reasons cited for this include line deratings, illiquid intertie capacity release markets, and pricing differentials resulting from California ISO congestion pricing (raising the cost of imports from the perspective of California utilities). Some increase in export capability could be secured relatively quickly and at low cost by resolving these issues. Over the longer term, and at much greater cost, expanding intertie transfer capacity could be undertaken. Current California RPS policy that only requires the equivalent of REC-associated energy to be imported within the calendar year provides little incentive for California utilities to support expanding intertie capacity. Policies encouraging transfer of associated energy nearer the time of production would provide incentive for expanding intertie capacity. Efficient operation of the interties could be compromised unless this policy was carefully designed. In-state development of RPS-qualifying resources within California could increase the incidence of excess energy events within California itself, possibly compromising the value of increasing intertie transfer limits, depending upon 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 productive 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 capacity to access California loads. Because springtime high wind periods are typically of several days duration, storage technologies may not be an economic means of leveling wind output. Storage economics have not been favorable in the Northwest because of modest heavy load and light load price differentials; however this analysis suggests that heavy and light load differentials may become more pronounced in the future. This, plus a growing need for capacity services, may improve the economic prospects of storage. Storage developed for other purposes may be able to provide some useful shifting of energy during excess energy events.

Measures Augmenting Energy Dump Capability

These measures would increase the ability to release surplus energy in an environmentally acceptable manner, thereby 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 establishment of total dissolved gas (TDG) limits.

Improved dissolved gas abatement: Gas entrainment occurs as spill plunges into the stilling basins below the spillway. 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,[13] thereby increasing gas-limited spill capacity.

Relaxed dissolved gas standards: Currently, exceeding TDG water quality standards is only permitted for voluntary 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 not likely prove feasible since water quality standards must be stringent enough to protect all the designated uses of the Columbia and Snake rivers and aquatic life is generally the most sensitive of those designated uses.

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 is generally agreed that there exists 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 Commission or Washington's Department of Ecology to go even further, at significant risk to salmon and other aquatic life, in order to deal with a surplus energy event seems highly improbable. 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 uncertain.

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

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.[14] While surplus energy events may not necessarily be considered "involuntary" in the traditional sense, 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 facility may have no practical application for the envisioned need as it is designed to operate for less than a second at a time.

While BPA's dynamic brake demonstrates the scale feasibility of load banks, commercially available load banks are designed for continuous service. A quick internet search found a handful of providers of megawatt-scale units.[15] 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 insulate BPA from negative pricing events by expanding 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. Perhaps the highest value of load bank technology is in providing a cost yardstick against which other solutions can be compared.

Measures Facilitating Curtailment of 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 to provide balancing reserves it is not apparent that further reduction in thermal output was possible. Slow response capacity such as the Columbia Generating Station was held at minimum operating levels to serve unanticipated loads as the warm season approached. Westwide, however, there may be opportunities to further reduce thermal operation during excess energy events. Plants can be retrofitted to reduce minimum operating levels. This can also increase the ability of these plants to provide balancing reserves. Replacing slow response thermal capacity, such as steam boiler units with faster-responding units like gas turbines, can reduce the need to keep capacity in operation to respond to unanticipated loads. Fast response units are also better-suited to provide balancing reserves.

---

[14] 7Q10 is the average peak annual flow for seven consecutive days that has a recurrence interval of 10 years.
[15] Avtron, Mosebach Manufacturing, Power House Manufacturing, Sephco, and Simplx.

Further curtailing thermal output would help use more low-cost, low-carbon hydro and wind energy, ease the severity of excess energy events, mitigate negative market price pressure, and facilitate more optimal 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.