B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

2009 Resource Program

Preliminary Needs Assessment

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Bonneville Power Administration:
Preliminary Needs Assessment Study

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Issue

Does the Bonneville Power Administration need additional resources (capacity, energy and/or ancillary services) to reliably meet its expected net obligations (load), non-power operations requirements, and operating reserve requirements? What is BPA's resource shortfall in terms of capacity, energy, and ancillary services?

Study Focus

This study was conducted as a preliminary step in defining tool(s) that will eventually measure resources available to the Federal system in comparison to the system's obligations. It assesses the existing resources used by BPA to supply its existing and expected power supply obligations (capacity, energy and/or ancillary services), representing load, non-power operations requirements, and operating reserve requirements from 2009 to 2013. The results of this study will provide input in determining whether BPA needs to acquire additional resources to reliably meet its expected net power supply obligations as BPA acts in concert with others to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply.

This is a preliminary draft only and may be modified in the future. This study is not intended to be, nor should it be construed as, a final BPA needs assessment study for any time period. As BPA collects more information and data on its supply obligations, this study will be updated or revised to provide a basis on which subsequent needs assessments can be made. (Subsequent *Needs Assessments* will evaluate longer term needs.) This study covers BPA's power supply and services obligations and functions as established by BPA's power marketing and transmission services.

Background

Load Uncertainty

With 2012, BPA begins a new set of contractual obligations under its Regional Dialogue Contracts. All 135 BPA publicly owned utility customers signed these contracts in 2008. The contracts give these customers the choice of purchasing federal power from the existing Federal Base System (FCRPS including CGS and non-federal purchases) in amounts up to their High Water Marks, roughly comparable to their existing BPA power purchases. Customers may buy this power at Tier 1 rates reflecting the costs of the Federal Base System.

Customers may also choose to purchase additional power from BPA, above their High Water Marks, at Tier 2 rates. Tier 2 rates will reflect the cost of power acquired to meet those requests. The amount of power customers may choose to purchase from BPA at Tier 2 rates is a significant variable in BPA's future supply obligations. The Preliminary Needs Assessment expresses both ends of the expected range of these obligations.

Capacity Questions

Historically, assuring resource adequacy for the BPA system has focused on energy because its predominately hydro power system is energy limited. The recent highest one hour peak load on the BPA system has been near 16,000 megawatts (MW). Given 22,000 MW of installed Federal Columbia River Power System (FCRPS) hydro capacity plus the 1,120 MW of the Columbia Generating Station (CGS) and access to the commercial power market, even with projected planned and forced outages, the FCRPS has been adequate to meet peak load. The primary source of uncertainty has been the volume and timing of streamflows to create energy to meet the load.

Faced with steady load growth and significant changes to the operation of the hydro system, that focus has shifted from energy to capacity. For instance, in 1994 the Pacific Northwest Utilities Conference Committee (PNUCC) made a first step toward capacity planning when it inventoried the capacity planning practices in the Northwest Region.[1] In that publication, BPA was shown as planning to the load created by normal weather conditions during winter months over a 50-hour sustained peak assuming existing resources with critical streamflow levels. This is in contrast to several other Northwest utilities that judged their capacity sufficiency against a one-hour peak load.

Over the 15 years since the PNUCC study, load has continued to increase and hydro operations are increasingly impacted by non-power water uses: In particular,

- Regional peak loads are growing relative to energy growth, and summer peak demand is increasing relative to winter.

[1] *Capacity Planning: An Inventory* Pacific Northwest Utilities Conference Committee, January 1994

- Biological Opinion (BiOp) requirements have further degraded the hydro system's annual average capability, severely limited the use of FCRPS to meet winter loads, and imposed significant seasonal reservoir operations constraints and spill requirements that impact system capability in those periods.
- Rapid growth of new non-dispatchable resources such as wind interconnecting to the BPA Balancing Authority (BA) has created significant new operating reserve obligations.

Fish operations are mandatory obligations of the system and are treated as firm obligations in this study. We plan our hydropower capabilities and operations within power available after these obligations are reliably met. The Preliminary Needs Assessment does not address potential emergency exceptions for public health and safety either of fish operations, flood control requirements, water withdrawal rates to avoid streambank sluffing, or other firm operational constraints.

Also, the recently executed Regional Dialogue contracts may create new capacity obligations in support of customer resources through Resource Support Services (RSS) including Forced Outage Reserves (FOR), and other products. Further, the hydro system is aging, creating a need for extended planned outages of generating resources.

These significant changes in FCRPS loads and resources reinforce that evaluation of BPA's Resource Adequacy is a timely and necessary exercise.

General Approach

This Preliminary Needs Assessment examines energy, capacity, and ancillary services. BPA has significant experience, expertise, and models designed to focus on energy assessments. In order to accomplish the capacity and ancillary services components, we needed to develop new methods and standardize definitions.

When discussing our task with other parties, we found that examining hydro system capacity is more complex than assessing thermal system capacity. Unlike hydro systems, thermal systems typically do not have a single stochastic fuel supply that may randomly limit the system capability to produce power across heavy load hour periods seasonally or hourly. The Federal hydro system has that kind of variability.

In April 2007, BPA established a capacity metric for measuring the capability of FCRPS hydro to meet peak loads. The capacity metric is defined as the average of the inventory on the six highest load hours during weekdays limited by any hour in the period when maximum generation is approached assuming the maximal amount of generation is shaped into these hours. For long-term studies, we have been using this metric with the 6 highest hours over 3 consecutive days of a heat or cold event (18 hours total). Over time, BPA will continue to test and refine the capacity metric so that FCRPS capability can be appropriately measured.

In addition to the focus on energy and capacity to meet load under various monthly and hourly conditions, there is a fundamental question of whether or not the combined

generators of the FCRPS have enough flexibility, given their various physical or mandated operational limitations, to meet all of the operating reserve and load demands. As a result, this study is formulated in two parts to assess the energy, capacity, and ancillary service questions independently and jointly.

In designing this assessment, the following essential questions were addressed:

1. **Should BPA count on energy supply from the open commercial market*?*** On one hand, expecting *no opportunity* to acquire energy on the open market seems too constrained because that is generally not our experience. On the other hand, counting on the ability to buy energy on any particular hour to meet load, particularly during extreme temperature events, is really like assuming there is free capacity for BPA to access during times of duress. We decided in this Preliminary Needs Assessment to assess the total need to acquire energy and capacity, leaving to later steps in the Resource Program the decision of how much of that need should be filled by long-term acquisitions and how much could be left for within-year marketing. In the end, the agency should determine its risk appetite explicitly and direct any subsequent resource acquisition program accordingly.

2. **What type of water conditions should we assume in the Needs Assessment**? Agency analyses have ranged from average to critical, as well as presenting the full spectrum of 70 year water conditions.[2] For energy studies, we have used a set of 70 water years to show the range of possible outcomes, and then focused on monthly P5,[3] P10, and critical water conditions.

   In our definition of FCRPS hydro system for 18-hour capacity, we have assumed average hydro generation and 10th percentile loads to roughly create a 5 percent combined event for purposes of capacity adequacy evaluation. As we developed this analysis, we considered this issue in light of the fact that all of the firm power contracts that establish our loads are predicated on critical water supply. (Critical water is approximately 10th percentile probability water supply as an annual average.)

3. **Should the capacity of the FCRPS be able to meet all loads, reserves, and non-power obligations under critical water to be adequate?** This was another area in which we had significant debate. We have approached this differently in different aspects of our analyses, and we will state our assumptions clearly and may run sensitivity tests at critical water in the future.

4. **What type of load conditions should we assume in the Needs Assessment?** This answer was similar to the hydro supply discussion. We have used a variety of loads for various analyses. Some analyses used average expected

[2] Water years 1929-1998, i.e. August 1928 – July 1998.
[3] The terms P5, P10, etc., used in this document refer to the 5th and 10th lowest percentile of probable conditions. Unless specified otherwise, the probability is a combination of water supply for a given water year, planned and unexpected generation outages, and stochastic load fluctuations.

loads while the capacity assessment used 10 percent loads for an extreme weather event. Where we have varied from this we note this explicitly. One of the questions we asked ourselves in this context is: Since we risk experiencing a critical water condition once every 10 years, can we afford to assume that we will not have a 1-in-10 year "cold snap" or a "hot spell" during this condition for capacity planning purposes?

There has also been a difference in our long term load forecasting methods versus our short term methods (two different models that both run in our Agency Load Forecasting tool (ALF) as well as different approaches to some of the other components of our net obligations). For the Preliminary Needs Assessment, we have spent months working to understand and resolve the differences in the different forecasting methodologies.

5. **Should we assume only load up to the customers' High Water Mark or also their load growth above the High Water Mark?** For the first pass of the Preliminary Needs Assessment, we modeled the entire load that BPA might be expected to meet. Thus, unless stated otherwise, the results mentioned here for 2013 energy and capacity assessments specify potential load associated with Tier 1, only, plus all of the potential load associated with the Tier-2 rate pool. In some cases, we have separated out the load associated with the Tier-2 rate pool. The results also include projected future load amounts that would be subject to the Tier 2 rate pricing.

Approaches A-D

Since any single approach to the overriding question of resource adequacy for the next few years may have its shortcomings, we approached this analysis through several avenues, labeled Approach A through Approach D. Each approach is documented more fully in its own section at the back of this document. Approach A is a study of 2009, used to give us a benchmark to compare to Approach B, our study of 2013. The main purpose of Approach A is to gain confidence in the results of Approach B. Approach B is the heart of the Needs Assessment for defining BPA's energy and capacity needs. Approach C is a study of the impact of carrying increasingly higher reserves to support wind resources. This study gives us a more detailed analysis of the system's flexibility and the effects of variable resources. Finally, we did a quick study of energy adequacy using the Council's Resource Adequacy Standard to ensure that our results are in line with the region's minimum expectation. Each of these studies provides insight into the resource adequacy of the current system and should be considered in the development of the Resource Program.

Approach A) Inventory Study 2009: This is a traditional examination of existing (2009) conditions and limitations, as measured by our inventory studies for energy, high load hour (HLH) energy, and 120-hour super-peak as well as within-year capacity studies. This study uses existing loads with short-term forecasting techniques and focuses on the

variability of the hydro energy supply to meet load. This analysis provides a basis for comparison with the 2013 studies presented in Approach B. Its key metrics include:

Study A1) Annual energy, HLH energy, and super-peak (120-sustained peaking) for multiple water years, with a focus on P5, P10, and critical water.

The term 'super-peak' analysis is used in the inventory study for the same metric as the '120-hour sustained peaking capacity' term in the White Book. It is a measure of the system's ability to meet the peaks day-after-day throughout the month.

Study A2) 18-hour capacity assessment for roughly 1-in-10 year extreme temperature events with median hydro. (This is a roughly 5 percent probability event.)

This 18-hour metric is a measure of the system's ability to meet extreme load events, not encountered every year. Meeting these events is a critical measure of system reliability. However, if the hydro system is flexed to meet such an extreme temperature event, it would involve borrowing a significant amount of water from other days and weeks. Thus, it is a good measure of reliability under duress, but it does not measure the ability of the system to meet peak events beyond 3 days. Therefore, we have decided to include the 120-hour super-peak assessment (discussed above) in addition to the 18-hour capacity measurement.

Approach B) Preliminary Needs Assessment 2013. This analysis is envisioned as input for the Resource Program. It is an examination of conditions projected for 2013 for energy and capacity and their ability to meet the load forecasted for that period. We picked 2013 as the first year to study because it is a few years out and it has a CGS refueling outage. For this study, agency subject-matter experts created our first *hourly* forecast of loads, resources, and obligations for multiple future years. This study uses long-term load forecasting techniques. The study also combines projected reserve requirements for the system with growing wind penetration. The net obligation and the reserve forecasts were used in Hourly Operating and Scheduling Simulator (HOSS) analyses to assess:

1. Annual energy, HLH energy, and super-peak (120- hour sustained peaking) for 70 water years. These studies are analogous to the typical within-year inventory studies, and thus provide the opportunity to observe the trend from 2009 to 2013.
2. 18-hour capacity, again analogous to the 2009 heat spell, cold snap studies.

Approach C) Wind Reserve Impact Study. This is an hourly analysis of the FCRPS' ability to meet reserve obligations without violating mandatory operating limits/requirements as new intermittent resources are added to the hydro system. This

study is based on wind fleet operation in the BPA Balancing Authority from no wind through the addition of all of the wind currently seeking interconnection status. The matching reserve requirement assumes BPA power and transmission operation protocols in effect as of the end of FY2008; i.e. wind generators continue to schedule with the equivalent of a two-hour persistence forecast. The study uses Auto Vista to review the hydro system operations that result under multiple levels of reserve requirements (seven levels) at multiple streamflow levels (high, median, and low). Auto Vista provides a high degree of granularity, allowing detailed review of the changes in the modeled hydro operations. The analysis identifies and measures the incremental change in hydro generation, secondary market activity, reserves violations, and spill and gas cap violations as reserve requirements increase.

This study uses actual loads from 2007 and does not incorporate load growth in the analysis. Load growth was deliberately omitted to isolate the effect of the increasing reserves required for wind integration. Incorporating increased load growth in these studies can be expected to exacerbate the complications created by the rising reserve requirements.

Approach D) Council Resource Adequacy Assessment: This approach assesses the FCRPS capability against the Council's Resource Adequacy test. The Council recently adopted a Resource Adequacy standard for the region. The standard is meant to be a minimum threshold for reliability. It is less stringent than the standard the Council expects utilities to use for resource planning and acquisition [such as in Integrated Resource Plans (IRPs)].[4] In the Council's adequacy standard procedure, each utility is allotted a share of Independent Power Producer (IPP) generation, seasonal imports from out-of-the-region, and non-firm hydro. In Approach D, we translate our *energy* position to the Council's assumptions. The Council has not yet finalized procedures for the Resource Adequacy *capacity* standard.

Overview of Results

Inventory Studies

Approaches A and B are standard BPA inventory studies that seek to match the Federal system resources with system load, measuring the resulting surpluses and deficits, if any. The model takes a deterministic approach. The studies take advantage of the hydro system flexibility that is routinely available. They do not include extra releases of water from headwater projects [except for permissible additional draft at Grand Coulee Dam (GCL) during heat/cold events], and include planned and forced outages. These studies provide results by month as well as by time of day (HLH v. LLH).

Approaches A and B identify shortfalls in both energy and capacity under certain hydro conditions in 2009 and 2013. Additionally, under certain water conditions, the inventory model was unable to hold the required level of downward regulating/load following reserve margin (DEC reserve) required to manage the wind resources projected for 2013.

[4] Per conversation with NWPCC staff.

The energy metric indicates a need to acquire energy to keep the system in balance. Furthermore, the HLH, superpeak, and 18-hour capacity metrics specify that the energy BPA acquires must have a reliable HLH capacity.

The energy and capacity metrics do not specify whether the acquisition needs to be dispatchable. However, the Hydrologic Simulator Model (HYDSIM) and HOSS models fail to meet the downward regulation (DEC) reserve requirement in 2013 under certain water conditions. This indicates that we would need a dispatchable resource to assist with DEC reserves unless the reserve requirement changes.

Ancillary Services – Wind Reserve Impact Study

Approach C used the Auto Vista model to establish a baseline study of hourly operations for the 2007 year under three separate water conditions (low, median, and high) Again, this study assumed power and transmission protocols in effect in FY 2008, and does not reflect recent work by the Wind Integration Team.

The baseline model studies showed a small level of operational violations, primarily spill violations during spring runoff. In actual operation, spill priority tables would be used to manage such high flow and avoid violations. These events can be managed without serious consequences to the region's electric supply.

With the baseline established, the models were rerun incorporating increased levels of regulating reserves. The added regulating reserves have the effect of reducing the flexibility of the hydro system.

- The required downward regulation (down reg) effectively increases the minimum generation level of the hydro system, because the Balancing Authority must be prepared to back off system generation to compensate for wind generation above its schedule without forcing operations that would violate other constraints.

- The upward regulation (up reg) has the effect of reducing the maximum generation level that the FCRPS can produce, so as to provide headroom in case the Balancing Authority must call on generating reserves to compensate for wind generation occurring below scheduled levels. The impact varies by both season and by water condition as well as by the reserve levels.

The impact of this loss of flexibility was measured in a number of ways. As the reserve requirements rise:

- The ability to peak the system declines.
- The wholesale market opportunity goes down; i.e. generation moves from on-peak to off-peak, filling the trough.
- Spill increases and unit efficiency decreases, causing generation volumes to decline.

- The number of operational violations increases, becoming unacceptable by the level of wind reserves currently projected for 2011[5].
- The additional reserve requirements are held mainly at GCL creating a reliability concern.

The details of the measurements are provided in the complete study description.

Each of these impacts listed above raises concern over the ability to continue to operate the Federal hydro system in a responsible manner. If the operational protocols in effect in 2008 remain unchanged, by the time wind resources in the Balancing Authority reaches the 2011 level it is likely that the system will have become very difficult, if not impossible, to manage without violating fish protection and reliability standards

There are ways to reduce or mitigate the loss of flexibility.

1. Reduce the regulating reserve requirement. A large component of the reserve requirement is due to scheduling error for the wind generation. At least a portion of this error can be removed through better scheduling techniques and experience. Additionally, if the wind resources are found to have more diversity than originally expected, the requirement may not rise as fast as this first forecast predicts.

2. BPA could allow wind generators to provide a portion of the downward regulation through agreements to back off generation if necessary.

3. Acquire some new flexibility for the federal system. The Approaches A and B studies, above, demonstrate a need for additional generation by 2013 in order to maintain load resource balance. The new resource(s) should be selected to provide system flexibility; that is, it should be dispatchable with a capacity factor that allows the system to take advantage of some shaping. This study is not complete enough to draw to a correlation between the amount of the lost flexibility and the size of the resource needed to mitigate the loss.

Thus, the Wind Reserve Impact Study addresses the effects of wind reserves on our system and how impacts should influence resource acquisition decisions. The reserve requirement identified in this study can be reduced by improving wind forecasting, strengthening agreements with wind power producers, installing less wind generation than projected, or by developing new approaches to assuring necessary reserves such as third-party supply, dynamic scheduling, mechanisms to allow within-hour sales of ancillary services, and other approaches currently under development. BPA is working with the wind community in its Wind Integration Team, the Northwest Wind Integration Forum, and as a member of ColumbiaGrid to identify and develop these and other alternatives that may have the effect of reducing BPA's reserve requirement.

[5] Because this analysis does not include load growth 2011 refers only to the wind resource penetration not the actual operating year. Additionally, improved forecasting of wind energy is expected to reduce the need for reserves, allowing the assimilation of more Wind generation before operations become acceptable.

Conclusion and Recommendation

Preliminary Needs Assessment 2013 Approach B demonstrates a need to acquire 750 aMW energy to meet load in 2013, including 2,000 MW in the heavy load hours in late summer and winter and smaller amounts for the rest of the year, if preference customers place all their load growth on BPA. Some of this need can be met by within-year purchasing.

The Preliminary Needs Assessment Approach B identified the following deficits in energy and capacity:

Annual Energy

Up to 750 aMW deficit with critical water. This includes an estimated 280 aMW for load in the Tier-1 rate pool [6] and up to about 500 aMW for load in the Tier-2 rate pool.

HLH Energy

Up to 2,000 MW HLH deficit at the P10 level if serving all load in the Tier-1 pool and all potential load in the Tier-2 rate pool. The largest deficits are in late August and winter. These HLH deficits are accompanied by comparable deficits in LLH. At P5, the deficit is up to 2,250 MW for HLH.
Notes: We need to acquire energy with a dependable HLH capacity.
Some of these deficits may be met by within-year purchasing.

Superpeak or 120-hour Sustained Peaking

We are deficit by up to 1,600 MW at P10. However, if we purchase the above-mentioned energy for HLH, that will also cover the deficit for the superpeak.
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18-hour Capacity

We are currently in load/resource balance for 18-hour capacity, but could easily be deficit if our loads are higher within the load uncertainty. If we make the above recommended purchases for HLH, we should have a comfortable 18-hour capacity surplus, enough to cover potential load uncertainty. However, if we buy a considerable amount of energy that has no capacity component, then we may need to add capacity.

Additionally, the Preliminary Needs Assessment found that we are not able to meet the full reserve requirements for wind integration under certain water conditions. The more detailed Wind Reserve Impact Study (Approach C) corroborated and defined the need to acquire flexibility to meet required reserves for wind integration. This would indicate that acquired resources to meet the load should be through a contracted, dispatchable generator with dependable capacity and the ability to load factor to help address the reserve issue.

[6] The estimate for Tier-1 augmentation for 2013 (280 aMW) is higher than the average estimate for Tier-1 augmentation in the 2012/2013 rate period because the CGS refueling outage in 2013 reduces the expected generation from the FCRPS compared to the two-year average.

The Wind Reserves Impact Study identified a need for flexibility:
Some portion of the resources acquired to satisfy BPA's power supply needs as identified in this needs assessment should also be able to add flexibility to the system; i.e., be dispatchable with more capacity than average energy. It is possible that more capacity than is identified in the needs assessment would be required to add the flexibility needed to manage the projected 6,670 MW of wind resource expected in the BPA BA by 2013.

Without fully quantifying the need for ancillary services, it is premature to specify how much the needs identified in Approaches B and C overlap. It is likely that the overlap is not 100 percent. Furthermore, ongoing work by BPA and the region may reduce the reserve requirement and decrease the need for ancillary services.

BPA is actively pursuing opportunities to reduce the regulating reserve requirement,, such as:

- Improving wind generation scheduling techniques.
- Creating a new Dispatch Standing Order, referenced in Large Generator Interconnection Agreements (LGIAs), that will allow BPA to limit the amount of reserves the FCRPS provides for the wind fleet while maintaining reliability.
- Pursuing opportunities to reduce generation imbalance such as promoting wind diversity and coordinating with other utilities for sharing area control errors (ACE diversity sharing).

The next Needs Assessment will include updated load assumptions and will address additional years in the Resource Program horizon. If the activities listed above are showing substantial progress toward the reduction the reserve requirement for wind integration, we will update the reserve requirement as well.

Uncertainties/Risks:

A number of assumptions made in these studies embody risks and uncertainties that we need to keep in mind.

- The Preliminary Needs Assessment identifies the full range of potential needs, from service to the Tier-1 rate pool only through service of all preference customer load growth in the Tier-2 rate pool. The actual outcome could lie in between..

- If the recession proves to be deeper and/or longer than a slow-down in 2009, net requirements might be less. We have estimated that this effect could be about 75 aMW. One specific impact of a recession could be a reduction in large industry and a decrease in the DSI loads.

- Our deficits could be bigger if we lose generating capacity. In this study, we assumed full CGS generation during the extreme temperature events for the capacity assessment. In the energy assessment, we "gamed" CGS outages. A prolonged CGS outage is very rare, so it is in the low-probability tail—low probability but high risk.

- If the reserve requirements are reduced significantly, then we might be able to move more water and generation into HLH and reduce the deficit in HLH.

- In the capacity analysis, there is some uncertainty in the effect of extreme temperature on the loads. Because we do not have many years of data with loads like today (less DSI, more residential/commercial), we do not have a high confidence in the temperature effect on loads. The combination of forecast error and the possibility of larger temperature-effects on load cause a 1,000 MW load uncertainty. There is an intrinsically large volatility of the effect of temperature on load. We use about a 900 MW temperature effect for February peak and 800 MW for August, but it could be 1,000 MW higher. Therefore, the loads could be higher by 1,000 MW. If the extreme-temperature loads are indeed larger by about 1,000 MW, then we will be capacity deficit in the winter and summer.

- Another uncertainty involves fish and other non-power constraints. Changes in operating requirements may reduce the amount of energy the system can produce and/or reduce the flexibility of the system.

- The models have limitations. For example, modeling the full operating characteristics of reserves has not been a big concern in the past, and up to now we have been able to model them as reductions in unit availability. As the need for spinning reserves increases, not every model will capture that completely. This is one of the reasons why we are using multiple models, but still we must remember that we are treading in uncharted territory and may be missing something.

- The Wind Reserve Impacts Study is a single-issue analysis that isolates the incremental impact of holding additional reserve requirements on the Federal system. One of the largest uncertainties is what our future reserve requirement will be. Also, this study does not capture any secondary-effect risks associated with deployment of reserves to balance a variable wind profile such as: managing forebay bounces, navigation issues, transmission redispatch and reliability if GCL is disproportionately responding to large swings, and unit operational cycling costs.

- And, last-but-by-no-means least, we have to keep in mind that water conditions could turn out to be anywhere over the wide range of possible streamflows.

Needs Assessment Next Steps for Approach B

- Update assumptions in the load forecast (update Slice percentage and new Slice participant list, adjust for economic slowdown as deemed appropriate, and adjust for other discrete changes in customer load and dedicated resource allocations).

- Update reserve requirement if new numbers are available.

- Rerun HOSS for 2013 as well as additional years in Resource Program time horizon.

- Hand off results to Resource Program for portfolio development. Later rerun HOSS with the preferred portfolios to measure their ability to satisfy the needs.

- Work with Council on Resource Adequacy test for capacity.

Approach A = Inventory Studies 2009

BPA routinely studies its power supply inventory for the current year using HOSS. In addition, the agency produces capacity assessments for cold spells and heat spells for the current year. These studies serve as a good baseline of current needs, and can be used as a gauge for 2013.

In actual operations in 2009, we are seeing challenges associated with variable wind power production, particularly due to generation imbalance, differences between scheduled and actual power production.

- With the current level of online wind generation (over 1800 MWs of installed capacity as of February 2009), duty schedulers are advised to operate with 500 to 600 MWs of additional operating flexibility to accommodate within hour movement and scheduling inaccuracies from the wind fleet. These recommendations resulted from issues with existing wind uncertainty and improvements in BPA's reserve forecast methodologies and well exceed the 203 MWs BPA originally projected for this year.

- In 2008, which ended with over 1500 MW of wind capacity installed in BPA's BA, wind generation exceeded schedules by 400-730 MW on numerous occasions and under-generated by 749 MW on October 2 and about 950 MW on December 29. On June 30, 2008, the transmission dispatchers first called the wind generators requesting that they back off generation because of the large deviations from schedules (generation imbalance) and made headlines in The Oregonian. [7] With the wind fleet projected to grow to 4,500 to 6,600 MW in the next few years, these deviations could triple or quadruple in magnitude.

- Prior to 2009, BPA carried about 650 MW total operating and regulating reserves. When we performed the analyses for 2013 (Approach B below), the regulating and operating reserves requirement was about 2,500 MW INC and 3,300 MW DEC.

As a baseline for comparison with 2013, we first present studies for 2009. The inventory study for 2009 used conditions before the start of 2009 and showed that we are roughly 250-350 aMW deficit with critical water.

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[7] 400 MW in spring, 730 MW and 680 MW for two hours in August, 625 MW on Sept. 10, and 400 MW Sept 21. Source: Balancing Act: BPA responds to huge influx of wind power, November 2008 on BPA external web site for wind
http://www.bpa.gov/corporate/pubs/fact_sheets/08fs/Wind-balancing-act-Nov2008.pdf
Oregonian article:
http://www.oregonlive.com/news/oregonian/index.ssf?/base/news/1215226547277170.xml&coll=7

2009	P5	P10	P20	Critical Water (1937)	Average of all Scenarios
Annual Average Energy	-350 MW	-250 MW	250 MW	-350	1,350 MW

However, this simple annual average metric hides significant deficits in HLH during most of the year, as measured at P10 for example. Note that critical water is about P10 on an annual basis, but each month varies dramatically, where some months in critical water are near-normal. Thus, we assess each month individually at some probability level. The hydro system is surplus during the runoff period, but then has deficits up to 1,600 MW from late August through winter, as shown in the table below left. The table on the right shows that the 120-hour superpeak deficits are smaller at P10 (except August II[8]), indicating that the hydrosystem generally has enough flexibility to shape generation into the peaks.

FY2009
HOSS Estimated Inventory Summary - HLH Energy

3/10/2009	5%	10%	20%	Critical Water (1937)	Average of all Scenarios
October	-300	-100	150	500	700
November	-750	-500	-150	850	550
December	-1500	-1300	-950	-1150	450
January	-1450	-1200	-750	-900	1650
February	-1500	-1150	-400	-1350	1600
March	-650	-300	50	-1150	1850
April I	-1100	-850	-300	-1150	1650
April II	-700	300	1100	-1500	2750
May	-250	850	2700	950	3450
June	-500	0	1400	-200	3150
July	350	700	1250	400	2600
August I	-1050	-650	50	1000	1100
August II	-1850	-1600	-1250	-400	-200
September	-1050	-900	-650	-200	50
Average	**-850**	**-450**	**200**	**-250**	**1550**

FY2009
HOSS Estimated Inventory Summary - 120-hour

3/10/2009	5%	10%	20%	Critical Water (1937)	Average of all Scenarios
October	0	200	400	800	1000
November	-150	0	300	1200	950
December	-500	-300	-50	-250	1150
January	-800	-500	-150	-400	2050
February	-1000	-650	0	-700	1900
March	-200	100	500	-600	2200
April I	-950	-650	-50	-950	1800
April II	-700	350	1250	-1600	2750
May	100	1450	3250	1500	3700
June	50	550	2150	300	3500
July	750	1150	1750	800	3000
August I	-1000	-600	350	1350	1350
August II	-1750	-1500	-1150	-150	50
September	-650	-450	-250	150	400
Average	**-400**	**50**	**700**	**200**	**1900**

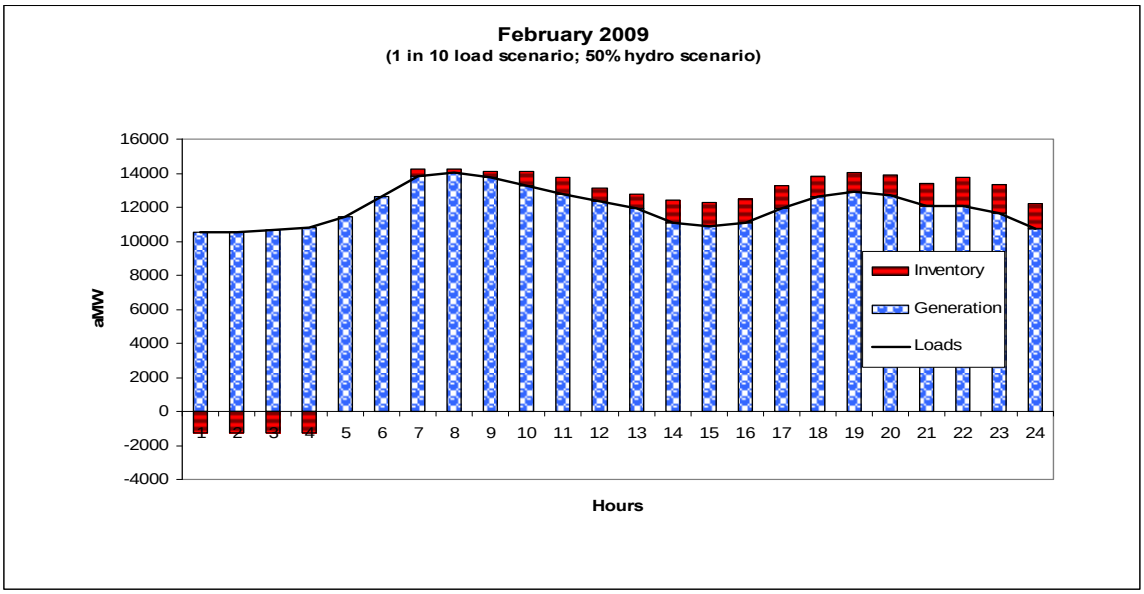
The 120-hour sustained peaking metric, or superpeak, is a measure of how well the hydro-system can meet typical peaks day-after-day (6 hours/day, 5 days/week, 4 weeks/month, 6*8*4=120). In this case, the hydro model distributes the water available for generation as evenly as possible through the month.

When an unusually extreme temperature event occurs, however, we would need to use hydro flexibility to move water from one period to another to meet the short-term need. The Council and BPA have adopted an 18-hour capacity metric for these instances. The 18-hour capacity metric measures the system's ability to meet load during the 6 highest-

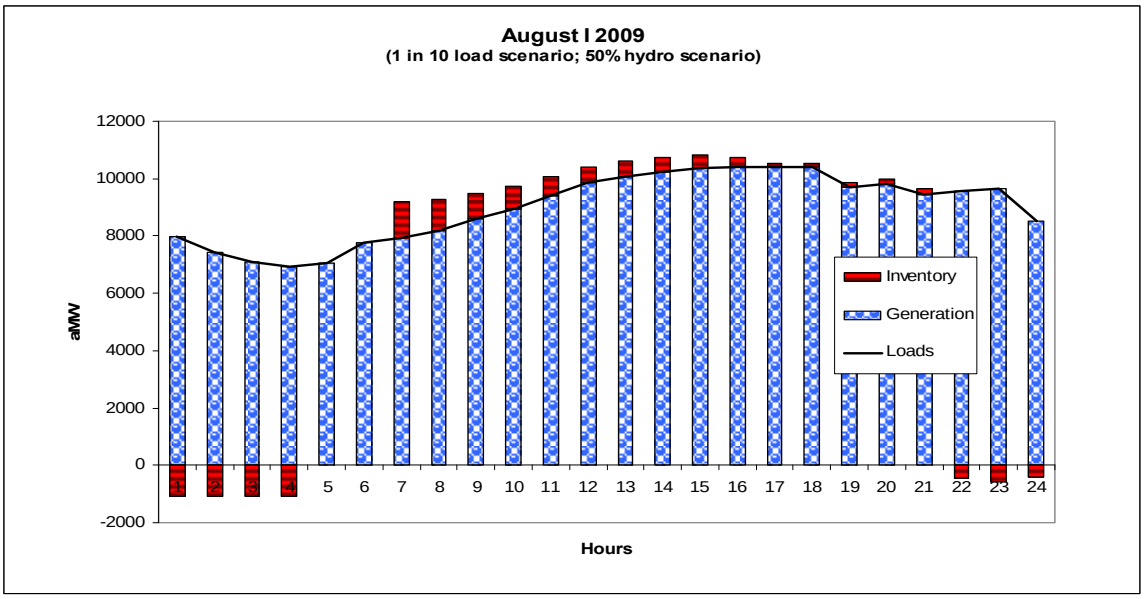
[8] April I, April II, August I, and August II refer to the first and second half of the respective months. Because conditions change significantly during these months, we model them as two time steps.

load hours of a 3-day cold snap or heat spell with temperature extremes that one might see once in 10 years. The BPA study uses median hydro conditions.

The figures below show the capacity of the system for a 3-day February cold spell and a 3-day heat spell in the first half of August. In both cases, the energy-limited capacity is smaller than the peak-limited (machine-limited) capacity, indicating that water, not turbines, is the limiting factor. The cold snap study shows about 500 MW of available 18-hour capacity (when combined with an assumed 1,000 MW of power purchases in the graveyard LLHs). The heat spell study has only 250 MW surplus 18-hour capacity, assuming purchases up to1,000 MW during part of the LLH period. Without these purchases, the capacity inventory would be lower.



Metric Summary	Energy Limited Capacity	Peak Limited Capacity Inventory	Final Capacity Inventory
6-hour	500	1950	500



Metric Summary 6-hour	Energy Limited Capacity	Peak Limited Capacity Inventory	Final Capacity Inventory
	250	1600	250

These 2009 energy and capacity studies indicate that the BPA hydrosystem is already tight under current conditions. As mentioned above, actual operations already show that we are having difficulties providing the flexibility to meet our reserve requirements for wind. Currently, we are managing these issues by the good fortune of not being at the P10 level of hydro supply, by buying energy and particularly buying HLH, by setting aside more reserves than required by reliability standards, and by occasionally curtailing wind generation. However, we will have even drier water years than the past few years, we are already buying HLH energy, and we are having to develop new operating protocols to maintain reliability with the volume of wind currently operating in our BA. If we extrapolate these experiences from 2009 to the future with close to triple the amount of wind integrated into the system, it is clear that we need to take action to cover annual deficits, HLH deficits, and ancillary service needs.

Approach B = Preliminary Needs Assessment FY2013: HOSS Analysis for Energy and Capacity using Hourly Loads

This paper presents results from the Preliminary Needs Assessment for 2013.[9] The analysis used the HYDSIM and HOSS models with forecasted loads for 2013 to assess energy and capacity. We picked 2013 as the first year to study because it is a few years out and it has a CGS refueling outage.

With critical water in 2013 the FCRPS is deficit on an annual basis by 750 aMW. This deficit includes both load in the Tier-1 rate pool as well as the full potential load of the Tier-2 rate pool.[10] In addition to the annual energy deficit, we find up to 2,000 aMW deficits in HLH energy and 1,600 aMW 120-hour superpeak deficits late summer and winter. The system is surplus by 200 MW in 18-hour capacity for an extreme cold event in February and surplus by 250 MW for an extreme heat event in August. As will be discussed in more detail below, the annual energy and HLH deficit is significantly larger than in 2009, while the summer and winter 18-hour capacity surpluses are only slightly smaller.

The term "superpeak" in inventory studies terminology is the same as the 120-hour sustained peak mentioned in the White Book. It is a measure of the ability of the system to meet the peak demand day-after-day. It measures the 6 highest load hours for 5 days a week and 4 weeks per month (6x5x4 = 120). Would we describe this as capacity or as energy? Sustained capacity is probably a little bit of each. It is certainly limited by the energy available to meet peaks all month, but it is also limited by the storage capacity in the run-of-river projects to provide peaking capacity every day.

The HYDSIM and HOSS studies presented in this Needs Assessment (Approach B) are not the best measure of system ability to flexibly deploy water behind various generators to produce ancillary services—that will be examined through Columbia Vista-Auto Vista studies. However, the HYDSIM and HOSS studies did show that the system was not able to accommodate all of the DEC reserves associated with integrating variable wind generation at the current estimated requirements. In April I, August II, September, and October, roughly half of the studies were not able to meet the DEC reserve requirement with existing resource supplies. In the worst case, we missed the DEC reserve requirement by 1,650 MW. Not being able to provide the full reserve requirement implies that the system did not have enough flow to generate minimum turbine flow plus the flow needed for the DEC reserves on a monthly basis. DEC reserves require that the system operate above minimum flows, so that when the DEC reserves are called upon, the system can reduce generation and still be above minimum flows.

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[9] Note that this run does not include the change in the list of Slice customers from the Dec. 1, 2008, contract signing. It also includes only 25 percent Slice. We will change the load forecast when the Needs Assessment is re-run in Spring 2009.

[10] The Preliminary Needs Assessment deficit is close but not exactly identical to the sum of Tier-1 and potential Tier-2 augmentation because there have been some changes in load and resource inputs since we began this analysis.

The INC requirements are not flow-dependent but rather require the system to generate below capacity in order to leave room for the system to increase generation if use of generating reserves is required. The HYDSIM/HOSS studies were able to accommodate the full INC requirement. The wind reserve effect study (Approach C) goes into further detail assessing the impact of the INC reserves. However, the general results of the two methods are consistent. Both models show increased spill and the shifting of generation from HLH to LLH.

Assumptions Overview:

The inputs for this study were finalized in fall of 2008. Some of the inputs are already outdated (and will change for the next Needs Assessment).

Loads:

- No major recession, but a slight slow-down in 2009. (Recession will be covered by scenarios.) A deeper recession would decrease our deficit, so it could count as an adjustment or 'contribution' to our acquisition strategy.
- Slice. We assume the existing Slice customer list, with 25 percent of the Federal Base System (FBS) in Slice. Within this, we assume Slice customers purchase a 70 percent/30 percent Slice/Block mix [*We will update this for the next Needs Assessment.*]
- BPA serves all potential load in the Tier-2 rate pool, i.e. all load above the High Water Mark. For some studies, we have also indicated how the results would differ if BPA did not serve the load above the customers' High Water Mark.
- Energy Efficiency at 56 aMW/year, not accelerated from Council's 5th Power Plan
- Direct-Service Industries (DSIs) We did not include DSI load.

Resources:

- We did not assume any purchases for Tier-1 augmentation beyond the 15 aMW Klondike III wind power purchase that is already complete.

Energy and 120-hour Superpeak Assessment:

- Used expected loads.
- Used 70 water years and recent Rate Case hydro-regulation.
- Used stochastic variability in CGS performance and load variability.

18-hour Capacity Assessment

- Used loads expected for a 1-in-10 year heat or cold event.
- Used the median hydro generation year.
- Allowed Grand Coulee to draft up to 1.9 ft/day (normal draft limits is 1.37 ft/day in model).
- Did not use extra water from Canadian projects or Dworshak Dam for capacity on a planning basis, even though in an emergency BPA could request more water. We don't want to plan to be in emergency conditions.

Reserve Requirements:

- Contingency reserves: based on peak control area generation by month; 5 percent hydro, 7 percent thermal; PBL obligation equal to 80 percent of control area obligation
- Regulation, Load Following and Generation Imbalance (based on regional wind fleet of 6,670 MW in 2013, with 2-hour persistence scheduling accuracy):
- **INC = 2,494 MW** (full amount modeled);
- **DEC = 3,300 MW** (only modeled the portion that the system could handle under all 70 water conditions; was short up to 1,650 MW. December and July were the only months that were able to meet the full DEC requirement in all years.)

Methods

The Preliminary Needs Assessment entailed generating a net obligation forecast, selecting a recent HYDSIM study, and then analyzing energy and capacity using HOSS. The HYDSIM study was available from the WP-10 2012-2011 Initial Rate Case work and contains the latest interpretation of BiOp implementation. The HOSS studies for inventory and capacity are similar to studies done routinely for within-year inventory analysis. The net obligation forecast, on the other hand, proved to be an enormous challenge.

To do the capacity assessment for this Preliminary Needs Assessment, we needed to forecast loads, resources, and obligations on an hourly basis for the years covered by the resource program, namely out to 2019. This had never been done before.

We began by determining the specific load and resource data required to calculate hourly residual hydro loads for the study horizon. Many of the long-term resource forecasts supplied by the various contributing groups within the agency were monthly, requiring algorithms to transform those monthly forecasts into hourly and heavy/light hour forecasts. Additionally, we adjusted the shape of specific projects where appropriate.

The load forecasts were developed using the new Agency Load Forecasting (ALF) tool, an efficiency improvement from the Marketing and Sales Enterprise Process Improvement Project (M&S EPIP). ALF is a statistical approach that allows the customer load to be influenced by heating and cooling weather conditions. It explicitly models new industrial production sites in a customer's service territory. It continues to use the time-series-based regression that reflects a fundamental assumption that historical patterns will continue into the future. Monthly forecasts of energy and peak were produced using this tool. To properly prepare for capacity analysis, we initiated a new process to develop the hourly loads for the BPA Net Requirements. This process required developing hourly load shapes for each customer or groups of customers and calibrating this shape to the monthly energy. This process allows for a different system level load shape to emerge as individual customers grow differently. This properly supports what will happen when faster growing customers with increasing summer loads influence the overall system shape. Because this was a new task for the agency, it did result in additional time for review from interested staff within BPA. A couple of key

assumptions embedded in this forecast are that the Slice customers would continue to change and that they would have 25 percent[11] of the system available to them. Additionally, we assumed that the agency would serve all above high water mark load as Tier 2 loads. The overall forecast of total retail load resulted in an average annual growth rate of 1.3 percent from FY 2009 through FY 2028. The summer and winter peaks' average annual growth rates are 1.1 percent and 0.9 percent, respectively. These are lower than the Council's growth rates of 1.6 percent for energy, 2.3 percent for the summer peak, and 1.7 percent for the winter peak for the same time period.

The capacity studies are weekly studies that measure the capacity inventory over the 6 peak load hours for 3 days (18 hours) using the median hydro generation with loads that are predicted for extreme temperature events. For this purpose, we increased net requirements using temperature adders provided by BPA Load Forecasting and Analysis staff. We increased Canadian Entitlement delivery to the maximum contractual limit. The temperature adders were based on a 1-in10-year occurrence over 3 consecutive days. Without this added extreme, there is a large uncertainty in the load for any given hour. Working with load data in the past, we have seen a 300-500 MW change in load when you constrain for conditions that typically explain the variability. With the uncertainty of the weather impacts, this range would be greater. On the generation side, we reduced Federal wind generation to 5 percent of the Federal share of nameplate capacity, following the most recent guidance from the Council. Though actual wind generation is often zero during extreme temperature events, the difference between 5 percent and 0 percent is very small for BPA's share of the existing wind fleet. System losses were set at 2.82 percent for normal weather and 3.59 percent for extreme weather.

The residual hydro load for the extreme temperature events served as inputs to HOSS for capacity analyses for February (cold) and August I (heat) events, again using an analysis procedure like the heat wave/cold snap studies that BPA Power staff produces for within-year analyses.

Recommendation: To be in load-resource balance on an annual basis in critical water, BPA would need to purchase up to 750 aMW for 2013. Of this, the current estimate is that about 280 aMW correspond to load in the Tier-1 rate pool while the remainder, about 500 aMW, would correspond to load in the Tier-2 rate pool, assuming all customers elect to have BPA serve this load. Therefore, the average energy deficit is between about 280aMW and 750 aMW for 2013. However, this deficit is by no means evenly distributed; there are significant seasonal deficits, up to 2,000 MW in HLH energy and 120-hour superpeak for winter and early spring at the P10 level and 2,200 MW HLH deficit at P5. Therefore, we need to purchase the annual energy with about 1,500-2,000 MW of HLH in late summer through winter to eliminate the HLH deficit (some of the

[11] At the time when we put together the load forecast, we thought that Slice would be expanding to 25% of the FBS. We also expected possible changes in the list of customers participating in Slice, but we did not know exactly which customers would choose Slice and therefore did not change the list of Slice customers.

energy may come from within-year purchasing). There is an uncertainty in the net obligation (at least 300-500 MW[12]), which is not included in the deficit.

Because we show a slight (200 MW winter, 250 MW summer) capacity surplus for the 18-hour metric, we do not necessarily need to buy peaking capacity for extreme temperature events. However, we also cannot afford to acquire mostly energy that has no capacity component such as wind generation because we do show a deficit in HLH. It is also important to remember that there is an uncertainty in the extreme-temperature loads that could be as high as 750 MW. There is intrinsically large volatility of the effect of temperature on load. We use a temperature effect of about 900 MW for February and 800 MW for August, but it could be 750 MW higher. If the actual load is indeed higher than in our forecast, we would have a large capacity deficit. This argument supports the earlier conclusion that we need HLH energy with assured capacity.

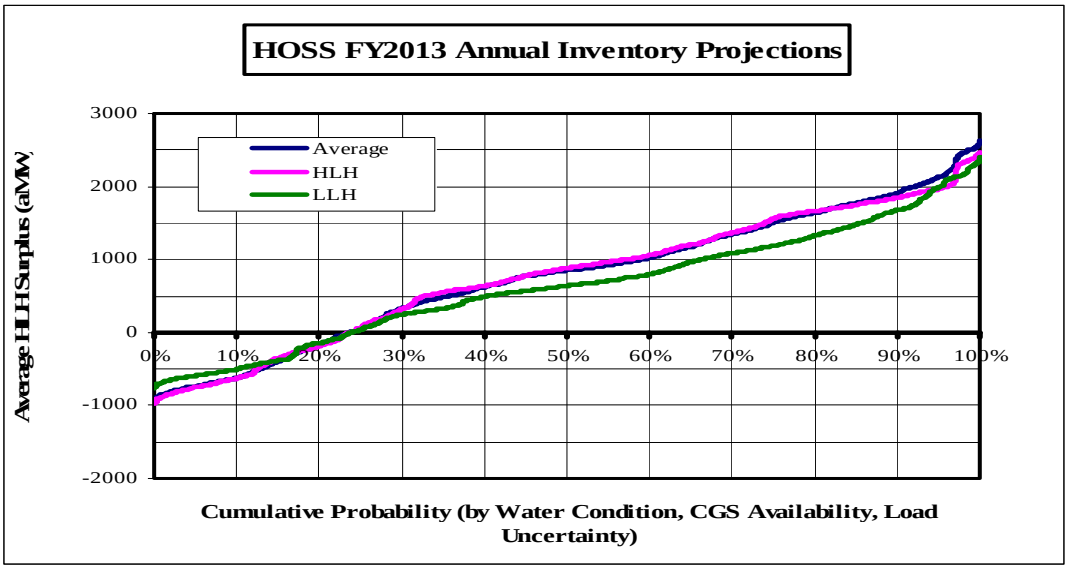
The energy and capacity metrics do not specify whether the acquisition needs to be dispatchable. However, the failure of the HYDSIM/HOSS models to meet the downward regulation (DEC) reserve requirement in 2013 under certain water conditions indicates that we would need a dispatchable resource to assist with DEC reserves unless the reserve requirement changes. The wind reserve effect study examined in more detail the impact of wind reserves on our system and question of whether or not we need a dispatchable resource. The reserve requirement can be reduced by improving wind forecasting, strengthening agreements to curtail wind, or installing less wind generation than projected.

The assumptions for this Preliminary Needs Assessment include full Tier-2 load, 25 percent slice with the pre-2012 slice customer list, no DSI physical delivery (or physical delivery with separate purchasing), and no major recession. Changes to these assumptions will require adjustments to the results. A change in the reserve requirements for wind would also impact our results. For example, lower reserve requirements would decrease the HLH and superpeak deficits under certain water conditions. We will update these assumptions/inputs in the next iteration of the Needs Assessment.

Results for Energy and 120-hour Superpeak:

This next graph shows that the system is deficit on an annual average below about the P25 level (25th percentile).

[12] The uncertainty estimate is based on the team's professional judgment based on looking at different load forecasting models and experience with operations.



One can portray the import of different deficit conditions at different probabilities:

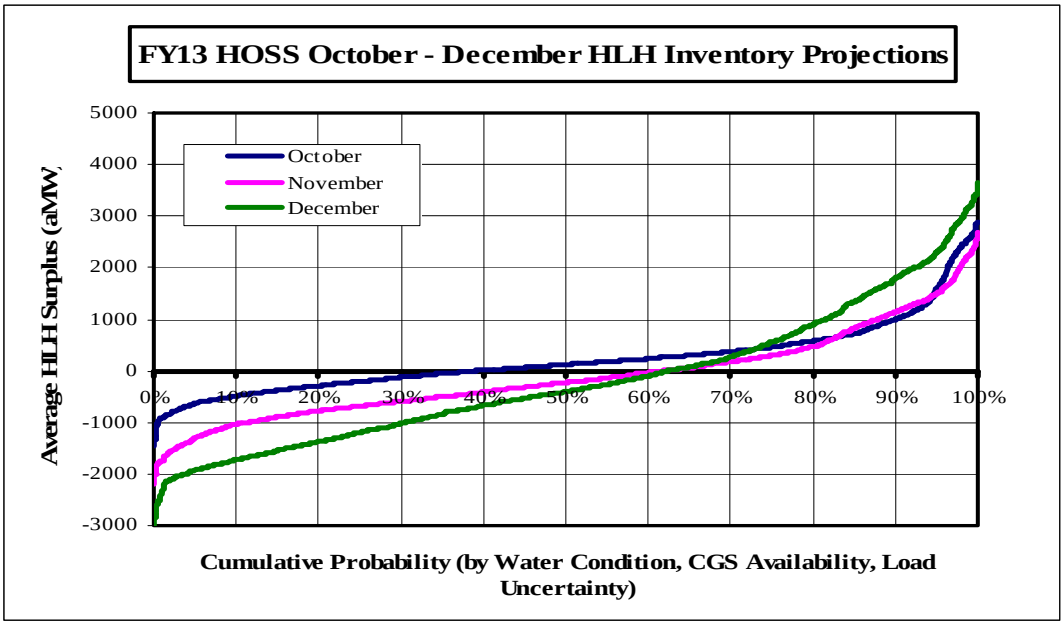
- Deficits at P5 mean a **potential reliability issue** in severe conditions (energy concern in severely dry years or capacity concern in extreme load event).
- Deficits at P10 mean **a potential issue meeting firm contract obligations.**
- Deficits at P20 mean **a potential need to purchase to meet firm contractual obligations.**
- Deficits or reduced supply at average water (close to P50 median) means **lower secondary revenues and higher power rates.**

Critical water is roughly a P10 water year in terms of HLH, but it is not a uniformly bad year. For example, November of 1936-1937 is above average. Thus, it is not a good measure of an adverse period for every month. Therefore, instead of focusing our monthly metrics on a single year with a particular shape, we chose to focus on the low-probability for each month.
The table below highlights these specific probability levels for the annual average energy.

2013	P5	P10	P20	Critical Water (1937) †	Average Water
Annual Average Energy	-750 MW	-600 MW	-150 MW	-750 MW	300 MW

† Note that Critical Water is around P10 or P5 on an annual basis, but each month in 1937varies dramatically, and some months are above-normal.

In the HOSS analysis, we examined the HLH, superpeak, and LLH energy. The following graph shows the HLH breakdown by month for October - December. In November and December we are deficit in well over half of the years, and in 25 percent of the cases the deficit exceeds 1,000 MW in December.



Graphs for other months and for LLHs are in the appendix. Much of the year, especially winter and the end of August, shows HLH deficits at the P20 level, and virtually every month is deficit below the P10 level. The following tables summarize the positions for HLH and 120-hour superpeak metrics. In almost all cases, the HLH deficits are the same or larger than the LLH deficits.

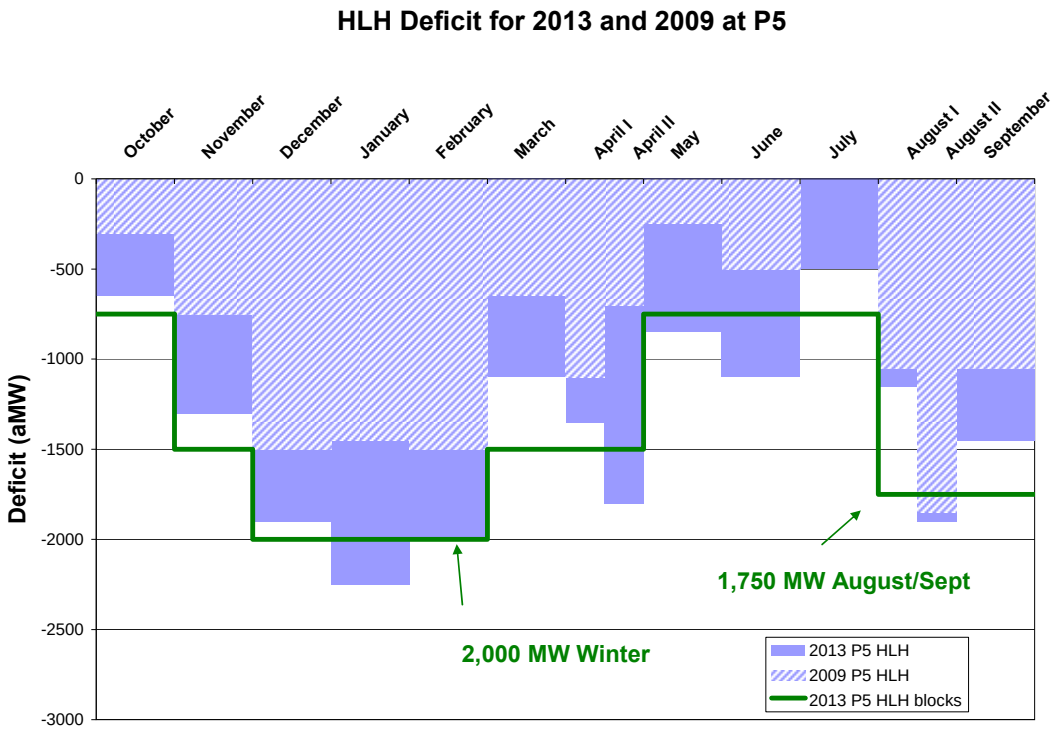
FY2013
HOSS Estimated Inventory Summary - HLH Energy

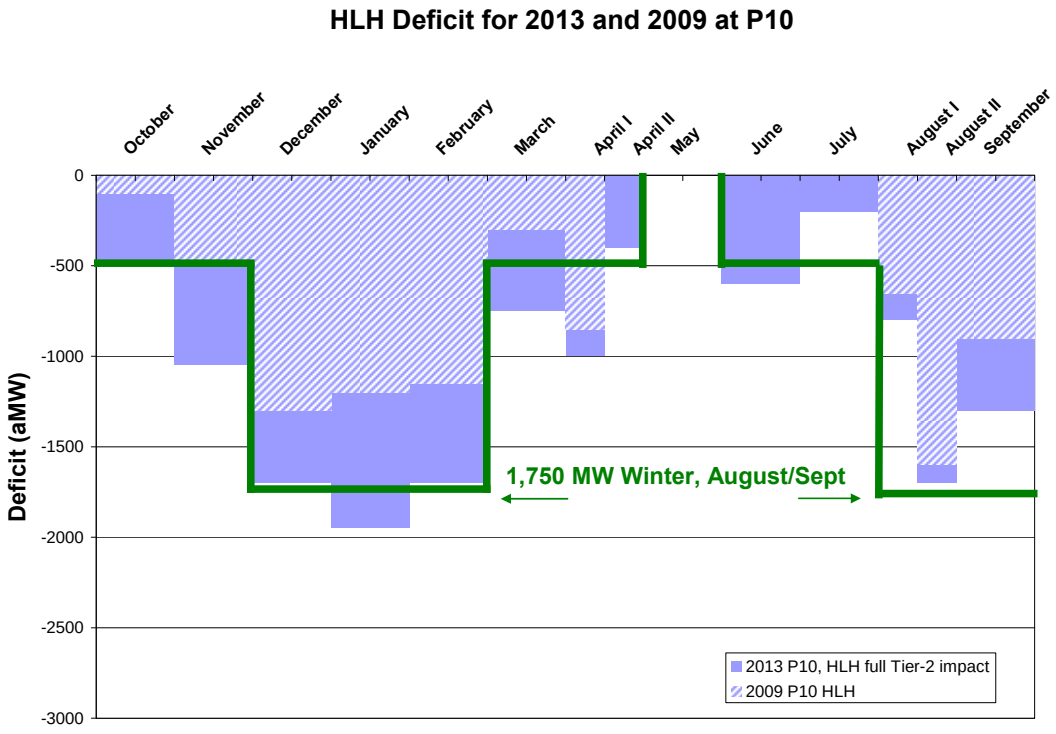
3/10/2009	5%	10%	20%	Critical Water (1937)	Average of all Scenarios
October	-650	-500	-300	0	200
November	-1300	-1050	-750	150	-100
December	-1900	-1700	-1350	-1600	-200
January	-2250	-1950	-1500	-1700	600
February	-2000	-1700	-1200	-1950	700
March	-1100	-750	-350	-1600	1250
April I	-1350	-1000	-700	-1500	1100
April II	-1800	-400	850	-2100	1800
May	-850	200	2000	250	2350
June	-1100	-600	1000	-900	2100
July	-500	-200	250	-550	1600
August I	-1150	-800	-100	750	800
August II	-1900	-1700	-1400	-550	-350
September	-1450	-1300	-1050	-550	-400
Average	**-1350**	**-950**	**-350**	**-850**	**800**

FY2013
HOSS Estimated Inventory Summary - 120-hour

3/10/2009	5%	10%	20%	Critical Water (1937)	Average of all Scenarios
October	-300	-150	50	300	500
November	-800	-550	-350	500	300
December	-1350	-1000	-500	-700	400
January	-1800	-1200	-750	-1000	950
February	-1350	-1100	-650	-1200	1050
March	-500	-200	150	-850	1600
April I	-1150	-850	-500	-1350	1150
April II	-1750	-150	900	-2100	1800
May	-500	700	2300	750	2550
June	-700	-150	1500	-550	2300
July	-250	50	500	-250	1800
August I	-1000	-650	250	1150	1000
August II	-1850	-1600	-1250	-300	-150
September	-1000	-850	-600	-100	0
Average	**-950**	**-500**	**100**	**-350**	**1100**

The following graphs show the HLH deficit at both the P5 and P10 levels (blue shade). The heavy (green) lines smooth the need roughly by season since the HOSS results show more granularity than what is reasonably precise 5 years forward. The lighter hashed areas are the 2009 inventory results for comparison.

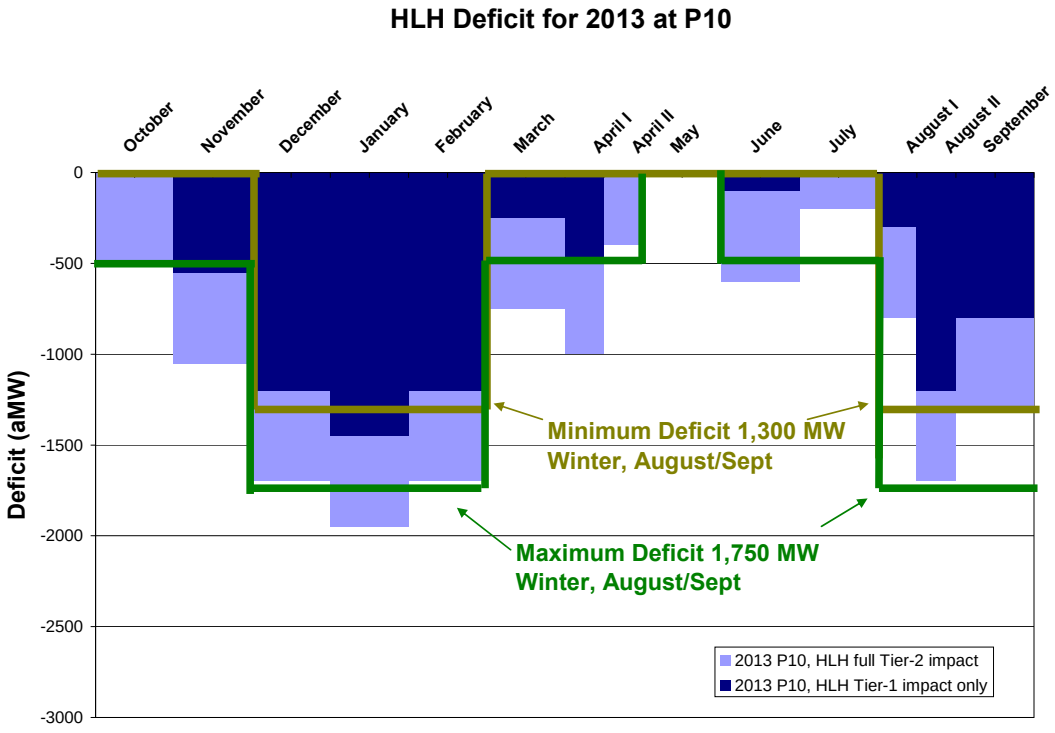




This study permitted LLH deficits, but assumed only 1,000 MW deficit was permissible in the graveyard period. Generally, the system was deficit at least as much in HLH hours

as in LLH hours. Thus, it would be possible to satisfy the purchase requirement with a flat purchase to meet the HLH and LLH deficits together. The model tries to shape as much water into heavy load hours as it can, thus the deficits that we see in HLH could not be made up with LLH purchases only. However, if the 1,000 MW cap on graveyard deficits were removed, the model could shape some additional energy into the HLH and lessen those deficits slightly.

The discussion in the preceding paragraphs assumed that customers would ask BPA to serve their entire load (Tier-1 and maximum Tier-2 rate pool loads). However, customers may choose to serve their load above the High Water Mark from sources other than Federal Generation. In this case, BPA's obligation would be reduced and the deficits would be reduced. The following graph shows the potential range in the HLH deficit. The larger deficit (jagged purple blocks and the green smoothed "need" lines are identical to the previous figure and correspond to the maximum load placed on BPA causing the maximum HLH deficits. The dark blocks and gold colored lines correspond to the deficit if BPA is only asked to serve load in the Tier-1 rate pool. (In this Preliminary Needs Assessment, we have not considered the potential impact of RSS services. If customers elect RSS services for resources that do not have dependable capacity, then BPA's obligation to serve would probably fall in-between the maximum (green) and minimum (gold) deficits.)



Comparison with 2009 for annual energy, HLH, and 120-hour superpeak

The 2013 Preliminary Needs Assessment shows up to a 750 aMW deficit with critical water and up to an 600 aMW deficit at P10 (if BPA serves all load growth), while the

study for 2009 had only 250 to 350 MW deficit. Thus there is a clear trend of decreasing inventory, due to a combination of 1.3 percent load growth, an increase in Canadian Entitlement payment, changes in customer dedicated resources as the Regional Dialogue contracts begin, less efficient generation as reserve requirements grow, loss of some resources, and other factors.

Compared to 2009, the 2013 study has significantly less inventory available during HLH but only a small reduction or even an increase in LLH. See the table below.. Effectively, there is an overall reduction in inventory combined with a shift of energy from HLH to LLH periods. We are already buying significant amounts in the HLH period for 2009, and will need to do even more in 2013 because the reserves required for wind integration are reducing the generation in HLHs.

Difference between 2013 and 2009 Inventories at the 10%
(Negative values mean less inventory in 2013)

2/13/2009	HLH	Spk	Avg	LLH	Grv Yrd
October	-400	-350	-250	-100	50
November	-550	-550	-450	-300	150
December	-400	-700	-450	-450	0
January	-750	-700	-650	-500	0
February	-550	-450	-450	-400	0
March	-450	-300	-400	-400	-200
April I	-150	-200	-200	-200	-300
April II	-700	-500	-750	-750	-850
May	-650	-750	-350	100	250
June	-600	-700	-400	-100	50
July	-900	-1100	-200	700	900
August I	-150	-50	-100	0	100
August II	-100	-100	-50	50	100
September	-400	-400	-354	-280	-189
Average	**-500**	**-550**	**-350**	**-200**	**50**

The shift in inventory from HLH (peak period) to LLH is caused mostly by the increased reserve requirements for the larger wind fleet expected in 2013. One reason for this shift is that the higher DEC reserves require generation above minimum turbine levels in the LLH (especially during the graveyard defined as HE01-04[13]) period. Ideally, the system would reduce generation to the project minimum levels in the graveyard period to save energy for the HLH (peak) period. Increased DEC reserves require generation above the minimum turbines at night, thus shifting energy into the LLH/graveyard period and out of the HLH period.

The increased INC reserve requirements also contribute to shifting energy out of the HLH period by increasing the amount of spare (unloaded) turbine capacity needed. In high flow periods, the reduced turbine availability will limit the amount of water that can

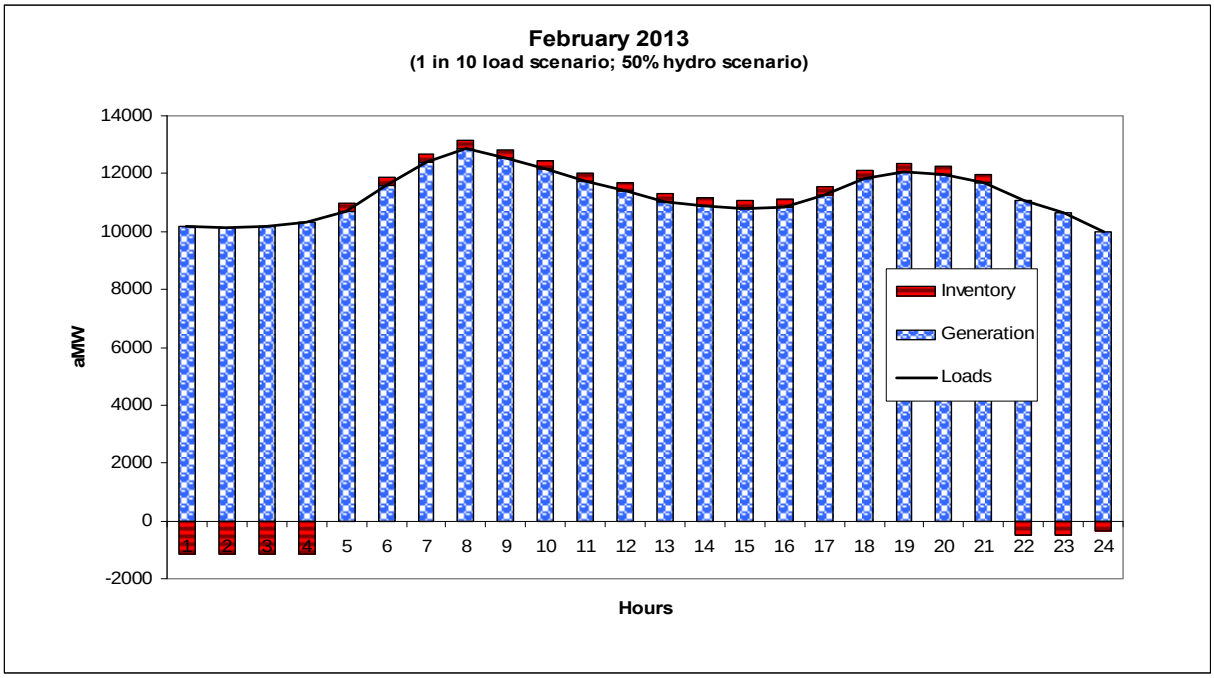
[13] HE 01-04 is "hour ending 01" to "hour ending 04," i.e. midnight to 4 am.

be shaped into the HLH period. This in turn shifts energy into the LLH period and in high flow periods can lead to increased spill.

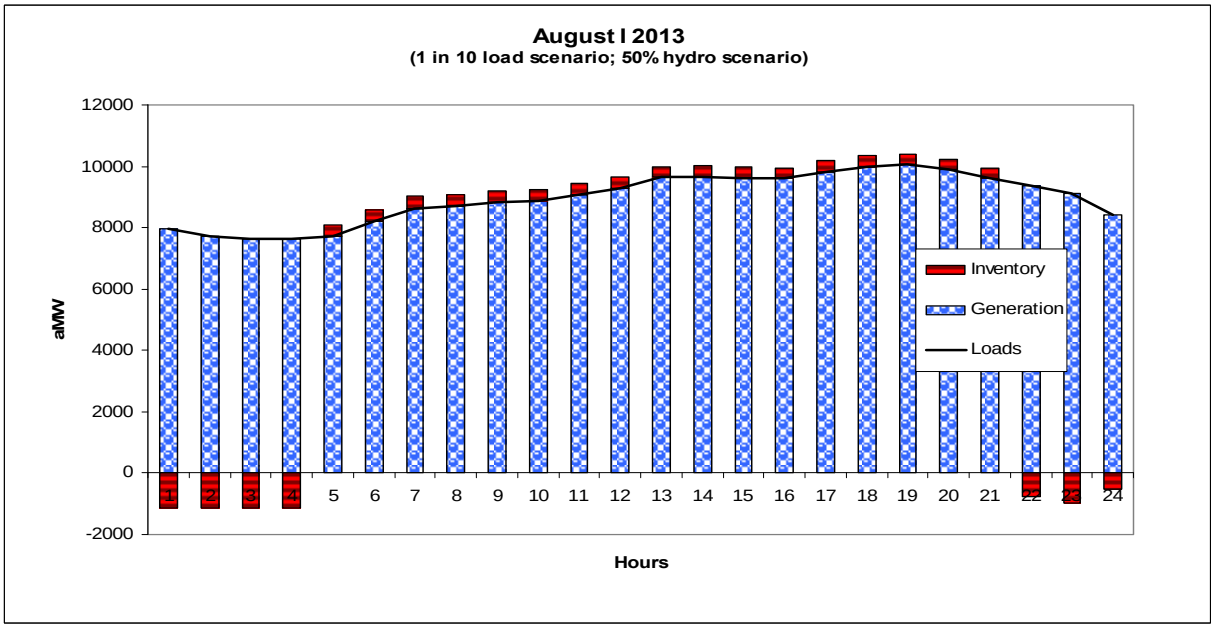
These HYDSIM/HOSS studies showed that we are not able to provide the full DEC reserve requirement in all months and all years from existing Federal resources. This implies that the system did not have enough flow to generate above minimum-turbine flow plus the flow needed for the DEC reserves. The needed volume of DEC reserves requires that the system operates above minimum flows, so that when the DEC reserves are called upon, the system can reduce generation and still meet the minimum flow requirement.

This analysis reflects system operation practices as of fall 2008. The DEC reserve requirements could be smaller if any of a number of initiatives comes to fruition.

18-Hour Capacity Analysis:



Metric Summary 6-hour	Energy Limited Capacity	Peak Limited Capacity Inventory	Final Capacity Inventory
	200	1350	200



Metric Summary 6-hour	Energy Limited Capacity	Peak Limited Capacity Inventory	Final Capacity Inventory
	250	1650	250

The above graphs show the 18-hour capacity analysis for extreme temperature events in 2013. The metric covers the 6-highest load hours over 3 consecutive days. The studies are performed with peak loads corresponding to a 1-in-10 year event with average hydro generation.

- February has a surplus of about 200 MW, with about 1,000 MW of LLH purchases. This surplus will grow if we purchase to meet the winter HLH energy deficit as long as the purchased energy has a significant capacity component
- August has a surplus of about 250 MW, with about 1,000 MW of LLH purchases.
- Note, when such an extreme weather event occurs, it would reduce the available energy for the rest of the month by about 250 aMW winter or 150 aMW summer.

The 18-hour capacity metric shows that we are still slightly surplus in 18-hour capacity, both during an extreme cold snap in February and an extreme heat spell in August for 3-day events. However, the combination of forecast error and the possibility of larger temperature-effects on load cause a 750 MW load uncertainty. There is intrinsically large volatility of the effect of temperature on load. We use about 900 MW temperature effect for February peak and 800 MW for August, but it could be 750 MW higher. If the actual load is indeed higher than in our forecast, we would have a large capacity deficit.

This result underscores the earlier conclusion that we have a need for HLH energy with dependable capacity. Acquiring this energy would cover the deficit if the loads turn out to be higher by the full 1,000 MW of uncertainty. Conversely, if customers choose to supply the energy above their High Water Mark themselves, without requiring significant RSS services from BPA, then BPA's future load could be lower, giving us a bit more surplus in 18-hour capacity.

These studies were performed using median hydro generation conditions. The only change made to operations was to increase Grand Coulee's draft limit to 1.9 ft/day from 1.37 ft/day (permissible a few times per year during events). Separate studies have shown that the 18-hour capacity is not highly dependent on water conditions. This is because our system still has enough flexibility to shape water into the peak hours of the day for a cold snap or a heat wave, even when there isn't that much water. (This is not quite the same flexibility used for wind reserves where you have only minutes' to a couple of hours' notice of the need to consume the reserves. In a cold snap, we typically have a couple of days to set up the system to meet the peaks.)

The water used to meet the demands during the extreme event is taken out of the rest of the month [perhaps also subsequent months, depending on the time of the year or that year's flood control and fish Variable Energy Content Curve (VECC) constraints]. If the energy comes out of the balance of the month, the capacity assessment presented here for February would reduce energy for the rest of February by about 100 aMW. Though this is a 'big hit' in terms of the need to buy energy, this 18-hour capacity assessment shows that the system can meet load during the 3-day event when market power purchases are likely to be extremely expensive or unavailable. The energy that must be made up for the

balance of the month would presumably be more available and less expensive outside the 3-day event. Fortunately, this type of cold snap is a rare event, estimated to occur only once every 10 years.

For an August heat-wave, the water needed to meet peak loads for a 3-day event reduces the energy available for the rest of the month by about 100 aMW. Again, the event analyzed here should be rare (once-in-10 years), and the key measure of the 18-hour metric is to be capacity sufficient during the event, when there would be little or no energy or capacity available on the market.

Under adverse hydro generation conditions, the system would have somewhat less energy. However, during an adverse water year, the system is already energy deficit, so we would presumably have to buy energy, including HLH, and that would assist with capacity to meet the cold snap/heat spell loads too, unless the energy were bought from an intermittent resource.

In this capacity analysis, we assumed that we would not be able to release additional water from Canada and headwater projects in the United States. While we do have the ability to flex Dworshak Dam during an emergency to gain energy at Dworshak and downstream, it is not prudent to plan the system to require emergency measures. We would still have the ability in short-term operations to use this flexibility.

Comparison of 2013 18-Hour Capacity with 2009

The 18-hour capacity assessments showed a slight decrease in capacity from 2009 to 2013, both in summer and in winter. This change is the net result of various effects that are operating in opposite directions.

Factors that increase 18-hour capacity are:

- the PacifiCorp peaking contract (575 MW) will have ended before 2013,
- hydro efficiency improvements by 2013, and
- potential effects from changes in customer dedicated resources (notably River Road[14] in summer).

Factors that decrease 18-hour capacity are:

- load is growing,
- the rising reserve requirements shift generation from HLH and peaks into LLH,
- the Canadian Entitlement capacity limit is higher,
- big unit overhaul in progress at Grand Coulee Dam takes turbines out of service, and
- potential small effects from changes in customer dedicated resources.

On net, these effects seem to offset each other, as we only see a small drop in surplus 18-hour capacity from 2009 to 2013.

[14] River Road is a 151 MW capacity combined-cycle combustion turbine owned by Clark Public Utilities.

We should consider ourselves at the edge of load/resource balance for capacity to meet summer and winter extreme peak loads in 2013. Given the uncertainty in load, we certainly will need the HLH purchases recommended in the previous sections unless customers do not ask us to serve much of their load above the High Water Mark.

Flexibility/Dispatchability/Ancillary Services

- Columbia Vista-Auto Vista studies being run concurrently are a more detailed assessment for ancillary service needs (see Approach C). Findings here are consistent with those studies, showing increasing occurrence of operating constraint or reserve requirement violations at about the same reserve level, near 2011.
- These HOSS studies did show that the Federal system had trouble meeting the DEC reserve requirement for wind generation beyond the 4,300 MW nameplate expected in 2011 and was not able to meet the 3,300 MW DEC reserve requirement for 6,700 MW nameplate in 2013, especially in August II – October and April I, where 35-65 percent of the years did not have enough water to meet the flows required to provide the required DEC reserves.
- Missing DEC reserves can create unacceptable reliability issues or violation of non-power system operation requirements. The hydro system would not be able to compensate for wind increases without violating some combination of Total Dissolved Gas (TDG) spill caps, missing Area Control Error (ACE) standards, or other reliability constraints.

For 2013, the current estimates have a wind fleet of 6,670 MW nameplate capacity. The reserve estimates for Regulation, Load Following and Generation Imbalance used in this assessment derive from a 2-hour persistence scheduling accuracy level:

- **INC = 2,494 MW** (full amount modeled);
- **DEC = 3,300 MW** (only modeled the portion that the system could handle under all 70 water conditions; was short up to 1,650 MW). Only the months of December and July were able to meet the full DEC requirement in all water years.

These studies (and similar HYDSIM and HOSS studies done for the WP-10 Rate Case) showed that the system had trouble meeting the DEC reserve requirement for wind generation beyond the 4,300 MW nameplate expected in 2011. The hydro system was not able to meet the DEC reserve requirement for 6,670 MW nameplate in 2013, especially in August II – October and February – April I, where 25-65 percent of the years did not have enough water to meet the flows required for the DEC reserves. The following table shows the number of years out of 70 where the studies were not able to meet minimum turbine plus DEC reserve flows.

	Number of Years Below Min Turbine													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr I	Apr II	May	Jun	Jul	Aug I	Aug II	Sep
Grand Coulee	28	3	0	1	4	9	26	5	4	6	0	4	34	42
Chief Joe	22	3	0	2	4	9	26	5	4	6	0	6	35	43
McNary	15	9	0	3	1	3	1	4	0	7	0	0	0	30
John Day	2	2	0	3	1	4	0	3	0	2	0	7	36	27
The Dalles	3	2	0	3	1	3	0	3	0	2	0	11	45	27
Bonneville	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The problem with the DEC reserves manifests itself primarily during LLH in the drier years. In order for the hydrosystem to have the flexibility to decrease generation at night (such as when the wind fleet picks up unexpectedly and decremental reserves are called-upon), the hydro system must be generating above its minimum level by the amount of the DEC reserves. However, in drier years, there often is not enough flow in the river to meet each hydro project's minimum flow plus the additional flow requirement for the DEC reserves.

As mentioned earlier when discussing differences between 2009 and 2013, the HYDSIM/HOSS studies showed that, as the reserve requirements increase, there is a shift in generation from HLH to LLH. One reason for this shift is that the higher DEC reserves require generation above minimum turbine levels in the LLH (especially during the graveyard defined as midnight to 4 a.m. or the HE01-04) period. The increased DEC reserves require generation above the minimum, thus shifting energy out of the HLH period into the LLH/graveyard period. An increase in DEC reserves will affect the system primarily in low flow periods.

The HYDSIM/HOSS studies showed that the increased INC reserve requirements also contribute to shifting energy out of the HLH period by increasing the amount of spare (unloaded) turbine capacity needed. In high flow periods, the reduced turbine availability will limit the amount of water that can be shaped into the HLH period. This in turn shifts energy into the LLH period and in high flow periods can lead to increased spill.

Uncertainties/Risks:

A number of assumptions made in this paper embody risk that we need to keep in mind.

- Our loads could be lower and our deficits smaller for a number of reasons. In the Preliminary Needs Assessment, we assumed that BPA would serve all potential load in the Tier-2 rate pool, but that may not be the case. If the recession proves to be deeper and/or longer than just a slight slow-down in 2009, net requirements might be less. The next Needs Assessment will have an updated load forecast and will include a deeper recession. One specific impact of a recession could be a reduction in large industry and associated loads.

- Our deficits could be bigger if we lose generating capacity. In this study, we assumed full CGS generation during the extreme temperature event for the capacity assessment. In the energy assessment, we "gamed" CGS outages, but a particularly prolonged CGS outage would fall into the low-probability tail that we might not have captured at the P10 or even P5 level.

- Roughly, loads could be +/- 300 to 500 MW for the expected case, with a larger upward uncertainty for extreme temperature loads.

- In the capacity analysis, there is some uncertainty in the effect of the extreme temperature on the loads. Because we do not have many years of data with loads like today (less DSI, more residential/commercial), we do not have a high confidence in the temperature effect on loads. The combination of forecast error and the possibility of larger temperature-effects on load cause a 750 MW load uncertainty. There is intrinsically large volatility of the effect of temperature on load. We use about 900 MW temperature effect for February peak and 800 MW for August, but it could be 750 MW higher. Therefore, the loads could be higher by 750 MW. If the extreme-temperature loads are indeed larger by about 750 MW, then we will be capacity deficit in the winter and summer.

- Another uncertainty involves fish and other non-power constraints. Changes in operating requirements may reduce the amount of energy the system can produce and/or reduce the flexibility of the system.

- The models do have limitations. For example, modeling the full characteristics of required reserves has not been a big concern in the past, and we have been able to model them as reductions in unit availability. As the need for spinning reserves increases, not every model will capture that completely. This is one of the reasons why we are using multiple models, but still we must remember that we are treading in uncharted territory and may be missing something.

- And, last-but-by-no-means least, we have to keep in mind that water conditions could turn out to be anywhere over the wide range of possible streamflows.

Approach C = Wind Reserve Impact Study (CV Auto Vista)

Purpose

The purpose of this analysis is to evaluate the effects on the FCRPS under the increasing reserve requirements associated with growing wind penetration in BPA's balancing authority area. This is a single-issue study that isolates the incremental impact of additional reserve requirements. It analyzes the effects on FCRPS operation of providing all wind integration reserves solely from FCRPS resources.

BPA is experiencing very fast, significant growth of wind power in its balancing authority, and has been and continues to work with the wind community on ways to facilitate the rapid growth of the wind power resource. The reserve levels used in this study are based on the *Regulation, Load Following and Generation/Load Imbalance* report prepared by the BPA Wind Integration Team (WIT) and presented on September 10, 2008. The installed wind capacity shown for each scenario year from 2009 – 2013 is based on actual interconnection requests received by the date of the WIT report. BPA Wind Integration Team actions, improvements in wind power scheduling accuracy, and changes in interconnection requirements since that date may lower the reserve requirement for a given installed capacity level.

The study seeks to identify the level of reserves where it appears that the hydro system is no longer functioning in an acceptable manner and reliability, hydro operation or non-power operating requirement violations may be expected to occur. Indicators of situations that could cause violations:

- Inability to hold downward regulation without violating system minimums (low flow).
- Inability to hold upward reserves without violating downstream spill constraints (high flow). This could result in failure to meet BiOp and TDG spill caps and/or other non-power requirements.
- Unreliable allocation of reserves – Grand Coulee (GCL) and Chief Joseph (CHJ) dams holding a larger proportion of reserves.

Note that the level of reserves associated with identified volumes of wind capacity is based on actual operations of the initial wind fleet interconnected at the time of the study. This relationship is likely to change as a result of the recently released Large Generation Interconnection Agreement (LGIA). Improved scheduling will reduce the regulating reserve requirement needed to manage a particular level of wind fleet. Thus the timing of the reserve effects may be extended to a larger wind fleet but the effects will be the same. Therefore, the model results shown in this report should be used for reference only.

Results Summary: The results of this study are consistent with expectations:

As the reserve requirements rise:

- The ability to peak the system declines.
- The wholesale market opportunity goes down; i.e. generation moves from on-peak to off-peak filling the trough.
- Spill increases and unit efficiency decreases causing generation volumes to decline.

- The number of operational violations increases, reaching unacceptable levels by the 2011[15] level of wind reserves.
- The additional reserve requirements are held mainly at GCL, which may cause reliability concerns.

These impacts are magnified as flow levels move away from the median. As can be seen in the following graphs the effects are seasonal, driven by flow, flood control, and spill requirements. Each of these points is expanded following the methodology section.

Methodology: The Columbia Vista (CV) Auto Vista module was used to perform multiple year-long hourly simulations of the Federal hydro system with varying reserve requirements and flow levels. Analyses were run for 21 sample cases; three flow levels (low, median, and high) combined with seven levels of reserve requirement. CV Auto studies enable a year long simulation of the hydro system at a finer resolution than has previously been available.[16]

The reserve levels used in this study are based on the *Regulation, Load Following and Generation/Load Imbalance* report prepared by the BPA Wind Integration Team (WIT) and presented on September 10, 2008. These reserve levels assume the wind facilities schedule with the equivalent of a two-hour persistence forecast for the projected installed wind fleet capacity. The installed capacity at the end of each scenario year is based on actual interconnection requests received by the date of the WIT report. It should be noted that improvements in scheduling accuracy and changes in interconnection requirements may lower the reserve requirement for a given installed capacity level. Therefore, the model results shown in the balance of this report are for the given reserve requirement levels and the years and installed capacity are subject to the assumptions in the WIT report and should be used for reference only.

Scenario Wind	**Base 0 MW**	**2008 1425 MW**	**2009 2105 MW**	**2010 3155 MW**	**2011 4330 MW**	**2012 5570 MW**	**2013 6670 MW**
Up Reg	679	757	894	1179	1414	1693	1983
Down Reg	837	884	1048	1453	1773	2174	2542

For this first set of studies the only variables are the reserve requirements representing the level of wind penetration and specific constraints that match the inflow volume. All of the studies are running against 2007 historical loads. The wholesale purchase market has a limit of 4000 MW in any hour and the sales market is effectively unlimited.

[15] Because this analysis does not include load growth, 2011 refers only to the level of reserves modeled not the actual operating year. Additionally, improved forecasting of wind energy is expected to reduce the quantity of necessary reserves, allowing the assimilation of more Wind generation before operations become acceptable.

[16] To get results in a timely fashion the simulation used a 7-period blocking rather than hourly for these studies. Each blocked, year-long study takes approximately 24 hours to complete. Each year long hourly study takes nearly three weeks to complete and a small sample comparison indicated that the results were not substantially different from the blocked studies.

Results

Peaking Capability Declines

The extra reserves required to follow the variability of wind resources decrease the flexibility of the hydro system. Hydro flexibility is available because there is not enough fuel (streamflow) to use all of the system capacity in every hour. While operations that provide flood control and protect fish have limited the operational flexibility to some extent there is still opportunity to generate more energy during the peak load hours and less in the off-peak load hours.

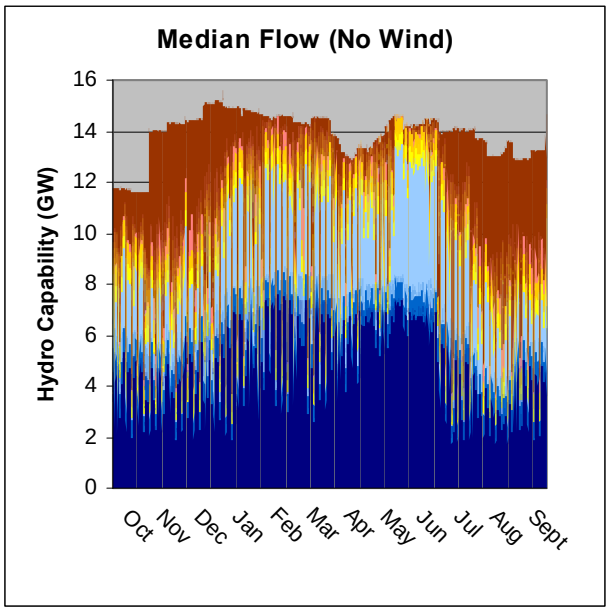
The increased reserve requirement needed to manage variable resources like wind power further limits the system flexibility. The **downward regulating margin** (*down reg*) increases the low end of the operating range while the **upward regulating reserves** (*up reg*) decrease the upper end of the operating range.

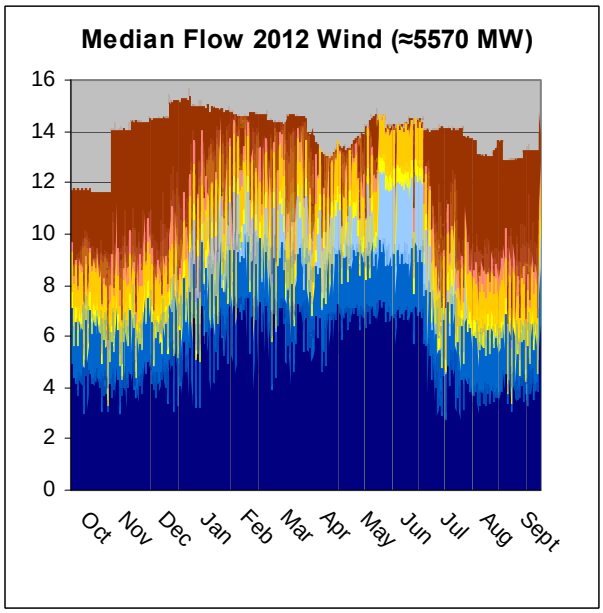
Down reg effectively increases the minimum operating level from the minimum flow level to a generation level that would allow the system to back off to minimum flow levels if the wind resource is greater than expected. *Up re*g is the regulating margin, in excess of the contingency reserves, that must be spinning with enough headroom to quickly replace wind resources that suddenly decline below the expected level. *Up re*g has a triple impact. First, the available capacity is decreased by the amount of the reserve requirement. Second, since these reserves must be spinning, more spinning units are required and the combined minimum generation increases. And finally, more units spinning reduce the plant efficiency, reducing the total energy that can be produced with the available streamflow.

The graphs on the following two pages provide a visual display of the hydro operations modeled using Auto Vista, with and without the increased reserves required to manage wind resources. The first page includes an example of the hourly optimized annual operation of FCRPS projects as modeled with and without the additional reserve requirement. On second page the detail is expanded to more clearly show the details of the changing operation for a typical week in each of the four seasons.

On each page the graphs on the left are from the study with no additional reserves for wind and the graphs on the right are the operations that require enough reserves to support the 2012 level of wind (about 5570 MW). In these graphs the three shades of blue areas represent generating resource including the generation that could be decreased without violating non-power constraints. The yellow and red areas are the unused available hydro capacity identified as different types of reserves.

Annual Hourly Hydro Operations – Model Results





Operations Category

- Total Hydro Capacity Available - NonSpinning Reserves
- Spinning Reserves Available
- Spinning Reserves - Identified for Reg Up
- Contingency Reserves - 50% Spinning
- Operating Generation Flexability
- Operating Generation - Reg Down Required
- Operation Generation - Minimum Levels

These graphs are examples of the hourly optimized annual operation of FCRPS projects as modeled with and without the additional reserve requirement. In these graphs the dark orange area represents the available capacity of the federal hydro system. The other colors are laid over the top to display how the capacity is used by the modeled operation. The three blue areas represent the generating resource:

- **dark blu**e is the minimum generation for each hour,
- **medium blue** is generation required for *down reg*, and
- **light blue** area is the portion of the hydro generation that is operating to maximize the value of the hydro system generating capacity; i.e., the discretionary (flexible) portion of the optimized hydro operation.

The yellow to orange colors represent the non-generating system capacity including both spinning and non-spinning reserves in various state of readiness.

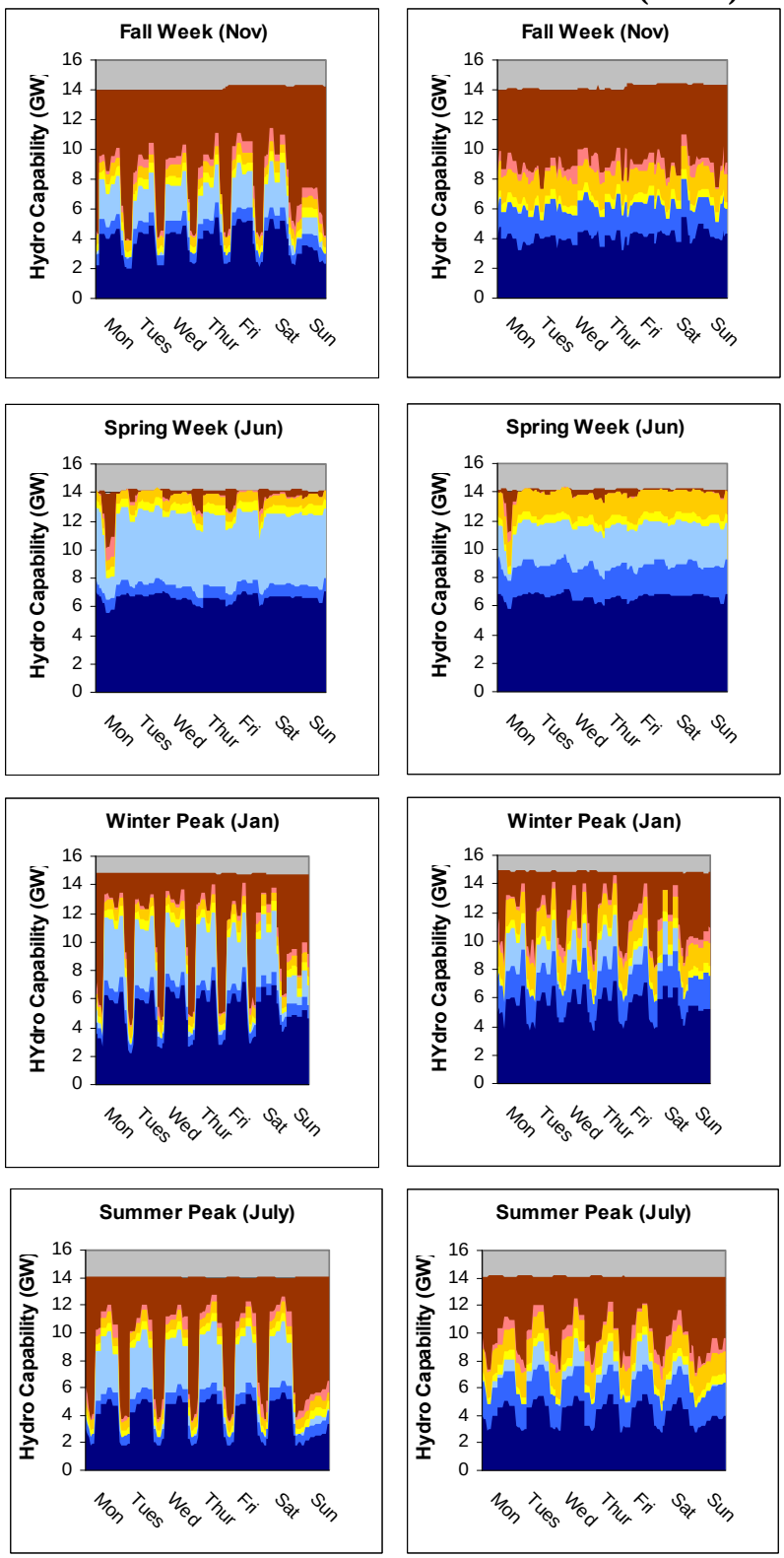
- **bright yellow** is the contingency reserve required by WECC (half spinning),
- **light orange** is the *up reg* that is used to manage load following and generation imbalance and, in the graph on the right, to balance wind resources.
- **peach color** is spinning resource that is in excess of the reserve requirements and
- **dark orange** is capacity that is available but not spinning in the given hour.

Notice that in the graph on the right, the base load generation (the two darker blue areas) increases and the system flexibility decreases. The reason is three fold: (1) The *down reg* requirement takes over some of the flexible generation; (2) The additional *up reg* requirement causes the model to bring on more hydro units increasing the minimum generation[17]: and (3), the required *up reg* reduces the maximum operating capacity for available for discretionary operations.

[17] Minimum generation is a function of the number units in operation for the hour as well as down stream flow requirements and changes depending on the number of units in operation.

Using the same color scheme as the previous page, these graphs show the detail of the reserve effect using typical weeks from each season. Even though both scenarios have the same load input, notice the flattening of the generation profiles when more reserves are required. In all seasons the higher reserve requirements force generation out of high load hours into the light load hours.

No Wind | **2012 Wind (~5570)**



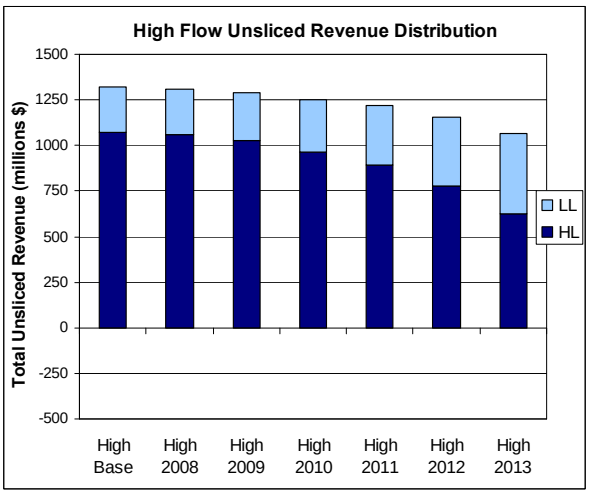
The fall season (with the lowest streamflow) is the most dramatic. In the right-hand graph, the required *down reg* leaves no room for any discretionary generation shaping. In fact, detailed analysis shows that many hours are violating the high *down reg* reserve requirement.

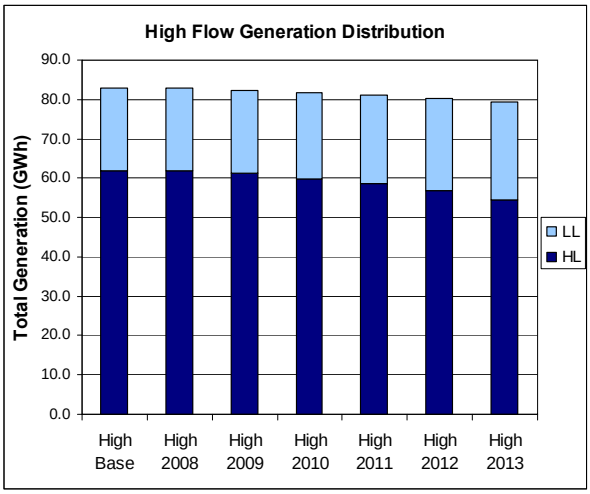
In the spring example, total generation has declined in the right-hand graph. At this time of year, high streamflows are being spilled to maintain the *up reg* requirement. While there is plenty of discretionary generation, any reduction in generation will result increase the amount of spill. The spill would result in lost energy and often violate the total dissolved gas limits.

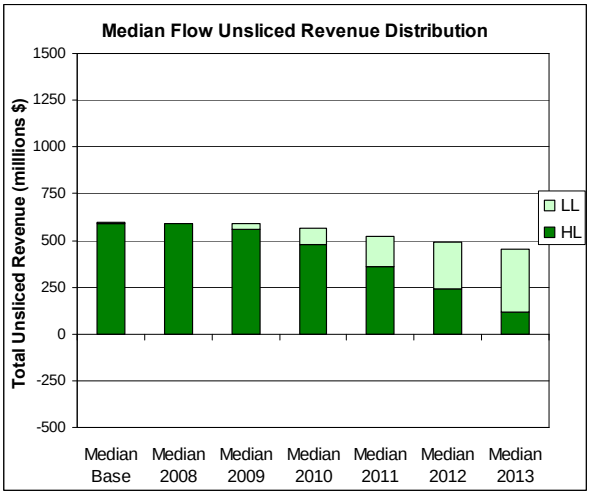
There are similar consequences during the summer and winter peak periods. Comparing the left and right diagrams, it is apparent that a significant portion of the generating capability is devoted to managing the reserve requirement. Water that is used, in the base case, to generate during high load hours is forced into the light load hours to maintain the *down reg*.

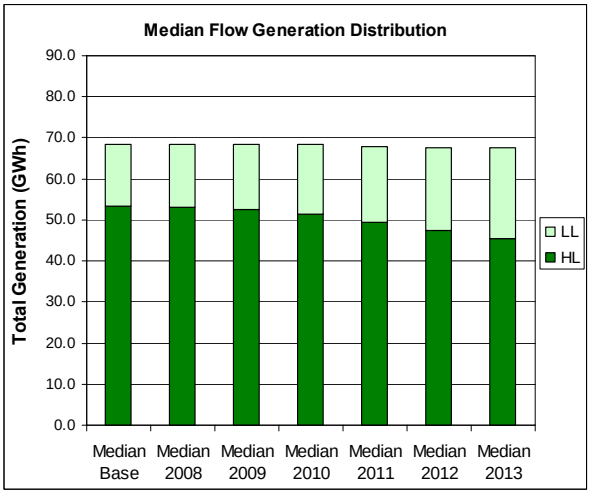
Secondary Market Opportunities Decrease

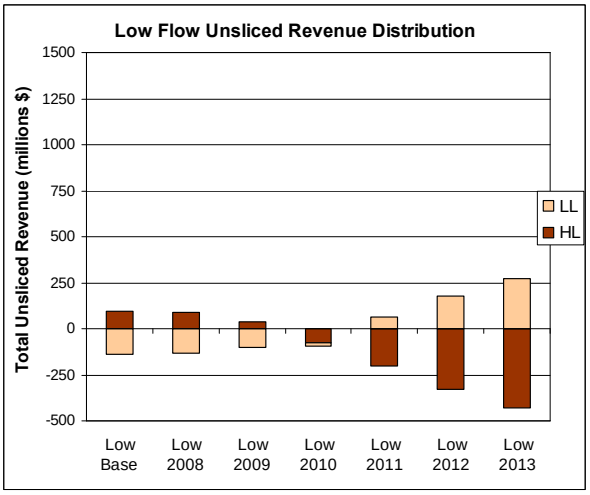
These graphs illustrate the effect on BPA power sales inventory and revenues as the wind fleet in BPA's balancing authority increases, assuming BPA provides all generation imbalance, load following and regulation from the Federal hydro power system. As the system is limited by the need for more regulating reserves due to the increase of variable resources, generation moves from on-peak to off-peak and wholesale market opportunity goes down.

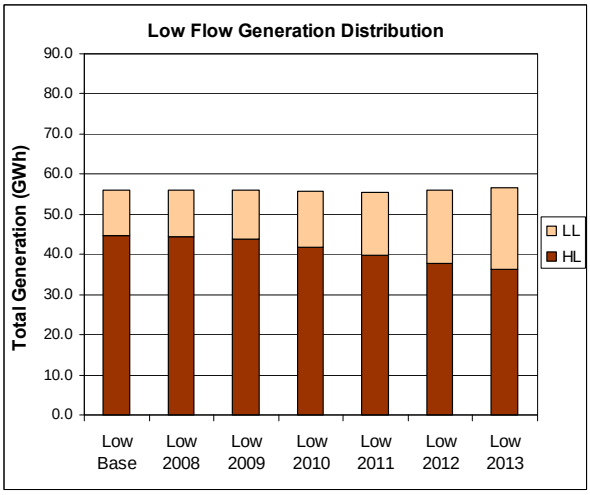








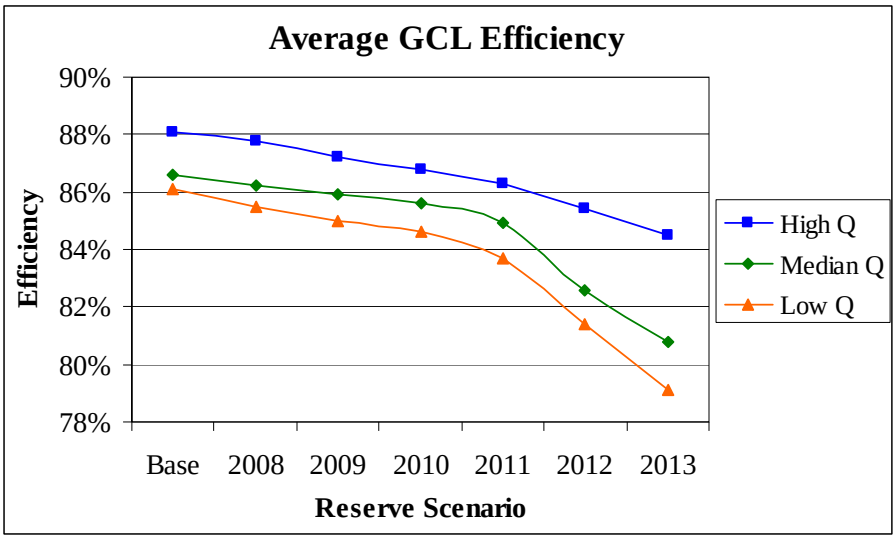




Unit Efficiency Decreases and Spill Increases:

The increased reserve requirement results in a reduction in generation and in some cases a need to bring more units on line. This effect is measured as a reduction in unit efficiency; i.e., the same volume of water produces less energy Grand Coulee (GCL), Chief Joseph (CHJ), McNary (MCN), John Day (JDA), and The Dalles (TDA) dams were modeled as plants capable of holding regulating reserves. The units of three lower river plants were limited by the 1 percent efficiency operating range prescribed by the Biological Opinion.

The graph below shows that GCL plant efficiencies decrease with the increasing reserve requirement. Efficiency on the lower river plants did not greatly change from the base scenario because the majority of the incremental reserve requirements ended up at GCL. To accommodate reserve obligations, the model brings more units online particularly when the regulating up reserve is the controlling factor. As units are brought online plant efficiency drops causing a reduction in generation. Costs associated with additional unit activity (e.g., breaker costs and unit wear and tear) were not addressed in this study.



The table below shows spill increases under higher hydrologic conditions and incrementally with higher reserve requirements. Regulation up reserves will induce additional spill when units cannot increase generation to meet increasing reserve requirements but are also required to meet elevation requirements. Consequently water that cannot be generated must be spilled.

Average spill during fish operations for high hydrology (kcfs)

FY	GCL (kcfs)	CHJ (kcfs)	MCN (kcfs)	JDA (kcfs)	TDA (kcfs)	Total (kcfs)
Base	13	14	183	134	135	***479***
2008	14	15	184	137	136	***485***
2009	15	15	186	139	136	***491***
2010	17	16	187	146	142	***507***
2011	19	17	187	151	144	***519***
2012	21	19	192	159	151	***542***
2013	24	21	196	166	156	***563***

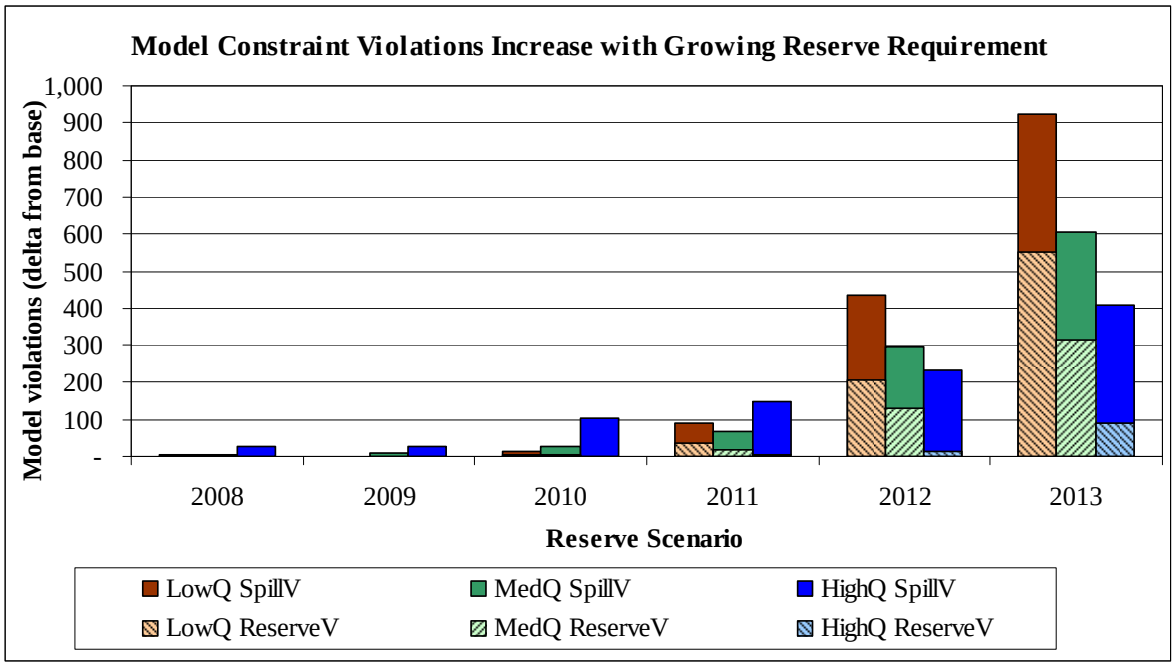
**563-479/479 = 17.5 percent increase in spill during fish operations for the 10 percent water year. These values will change based on flow volume and timing of spring runoff.

Model Constraint Violations Increase:

The graph below shows reserve and spill violations increasing as the size of the wind fleet grows, again, assuming BPA provides all reserves for the wind fleet in BPA's balancing authority from the Federal hydro power system. We developed a model constraint violation index[18] that combines probability and magnitude of reserve and spill violations. The index is for comparative purposes and does not have any physical meaning.

There are two types of spill violations that occur in the model results. In the low streamflow scenarios, the spill violations occur due to violating minimum spill requirements. In the median and high water year scenarios, spill violations are caused by exceeding the spill caps, which results in excess nitrogen saturation (TDG) levels in the water. During median and high flow base cases (no wind), variances in spill operations occur and spill priorities are used to manage high flow during spring runoff.

Incremental changes in spill and reserve violations increase between the 2010 and 2011 regulating requirement. As the reserve requirement increases, spill is used to try to manage the reserve requirement. This leads to increasing spill violations during spring runoff, indicating difficulty meeting BiOp operations. Also, the model increasingly cannot hold the reserve requirements needed to integrate the growing wind fleet.

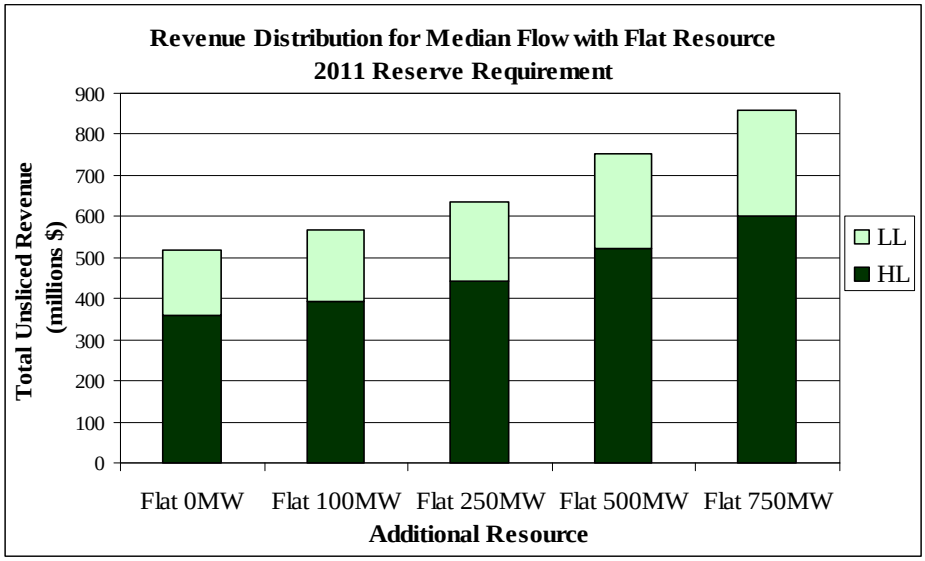


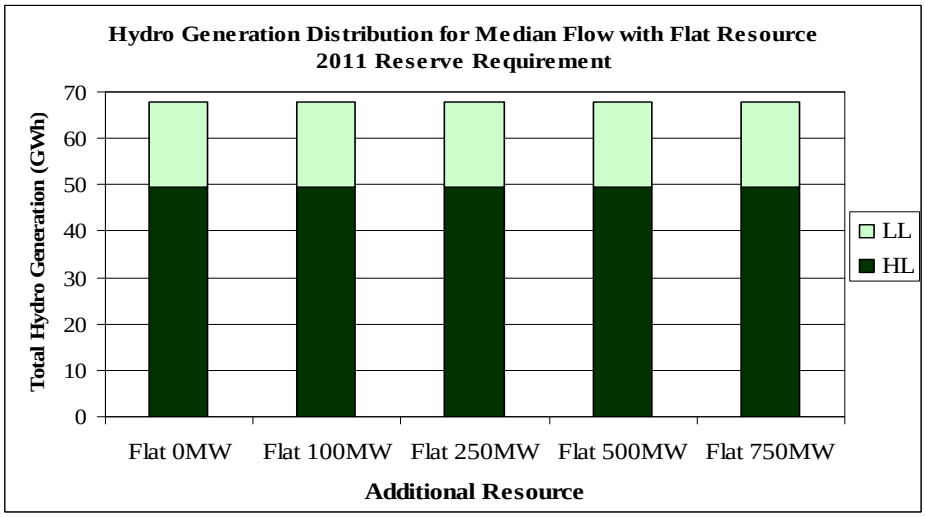
Many BPA analysts suggested that, since FCRPS has an installed system capacity of 22,000 MW that is energy constrained, if more energy could be supplied from another source, the freed up water in the FCRPS could be used in a more shaped, responsive manner to supply ancillary services rather than meet load on an hour. To test this theory, we added new energy resources to our system model, reran the analyses and calculated the operations violations. However, no

[18] The violation index was calculated by multiplying the percent of hours the metric was missed by the magnitude of the violation. The spill metric was calculated at TDA and JDA and converted using an average energy to flow ratio for each of the projects. Spill violations at other projects are still being examined.

significant change in the calculated violation index resulted from adding a flat 500 MW resource to the median flow scenarios at the 2009 and 2011 wind (future) reserve requirement levels and to the high and low flow cases at the 2011 level.

The graphs below show that, as expected, adding a flat resource of increasing size increases secondary revenues. However, because the generation distribution remains the same with the addition of the flat resource, the inability to peak the system still occurs and spill increases and unit efficiency decreases with the high reserve requirement. This indicates that the hydro system is already load factored to the maximum extent to move a given volume of water. The model has already determined the most optimal operation for the hydro resources. Therefore the addition of a flat resource does not free up hydro capability for other uses. The inability to hold downward regulation without violating system minimums also remains a problem. To change the model results, the resource added would need to reduce the reserve requirement on the hydro system. This could be a dispatchable resource that is able to hold reserves or an ancillary product from a third party supplier. Only a dispatchable resource capable of providing incremental and/or decremental capability, or that can otherwise carry a portion of the regulation, following and imbalance reserve requirements, can reduce the reserve amount carried by the hydro sources and make that capacity available for other uses.

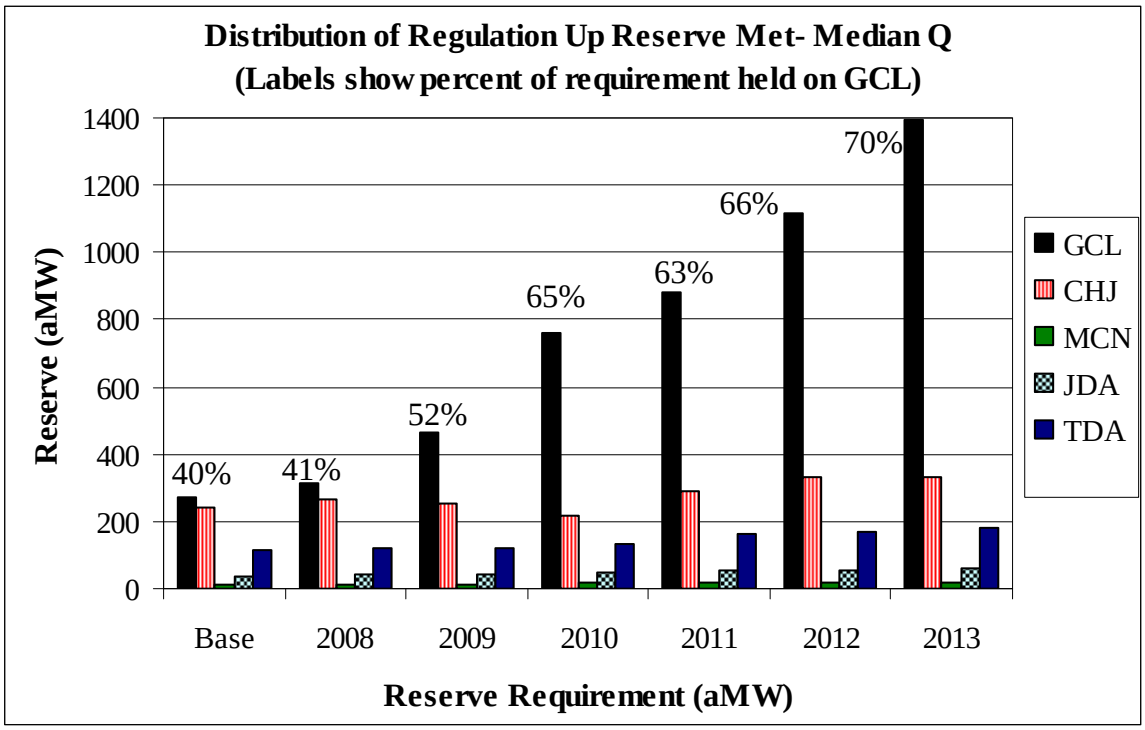


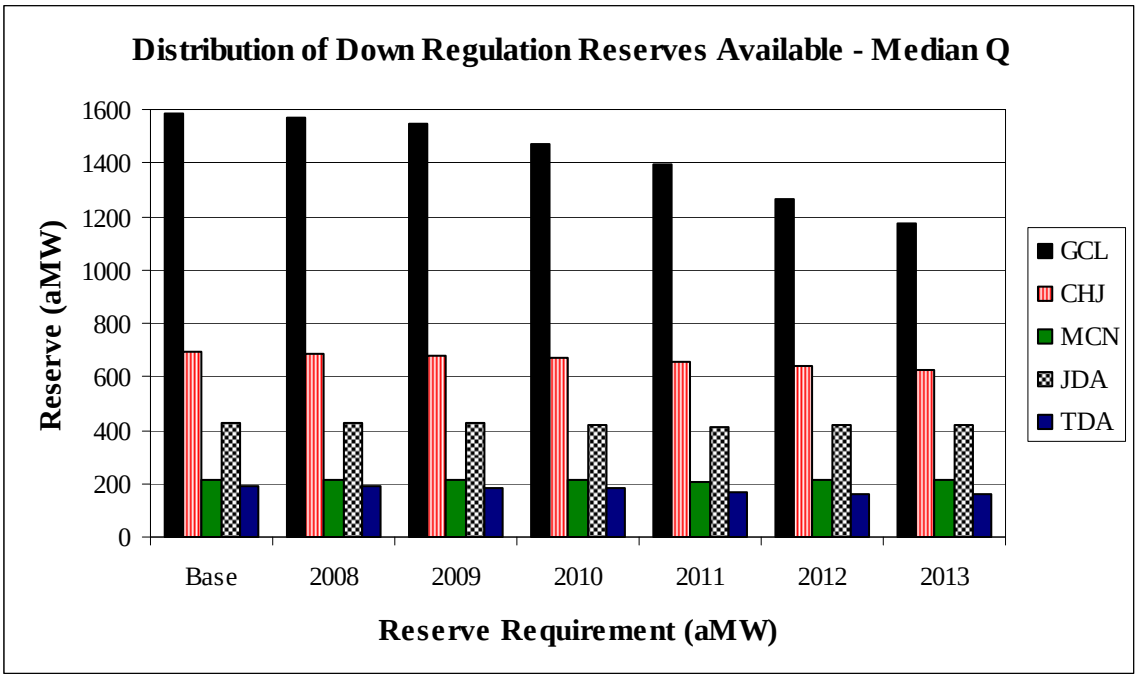


Reliable Allocation of Reserves:

Due to the existing power and non-power requirements on the system, the increasing reserve requirements needed to integrate wind are held at projects that currently operate with fewer constraints. The graph below shows that allocation of reserves on the Lower Columbia increases only slightly throughout the scenarios. The constraints on the Lower Columbia limit the ability of those plants to hold regulating reserves and any future fisheries requirements that further limits their flexibility (e.g. increased spill or requirements that limit reservoir content) would decrease the amount of regulating reserves and load following response on those projects.

The percentages in the chart below indicate the percent of total reserve requirement being met at Grand Coulee. In the base scenario, Grand Coulee holds approximately 40 percent of the regulation up reserves with the combination of Grand Coulee and Chief Joseph being 75 percent. The BPA transmission system has internal constraints and GCL and CHJ are predominantly on the "wrong" side of these constraints. Transmission was not modeled in this study so the increasing allocation of reserves onto GCL and CHJ may create transmission reliability concerns that are not captured in the results.





Regulation up reserves met at Grand Coulee increases according to the requirement associated with increasing wind penetration. At the same time, the down regulation reserves available are decreasing. This occurs as flow, which originally went through one unit, is dispatched through two units. The maximum generation under two units thereby gets reduced, increasing the regulation up but decreasing the regulation down capability.

Conclusion:

The ability of the hydro system to support increasing reserve requirements for integrating wind is limited by existing power and non-power constraints. As the reserve requirements rise, spill increases and unit efficiency decreases, causing generation volumes to decline. This decreases the wholesale market opportunity or causes load obligations to be met by other resources.

The incremental changes in operating violations increase noticeably between the 2010 and 2011 reserve requirement specified in the September 10, 2008, WIT study (INC range from 1,179 – 1,414 MW and DEC range from 1,453 – 1,773 MW), depending on inflow levels. This would indicate a system condition where meeting the reserve requirements and satisfying other power and non-power requirements would be extremely difficult.

The model results show that adding a flat energy resource does not significantly affect the amount of operating violations. To increase the system flexibility, the added resource would need to provide reserves in addition to energy; e.g. a dispatchable resource or ancillary product. The point of delivery should be selected to balance the increasing dependence on GCL for reserves.

This study uses actual loads from 2007 and does not incorporate load growth in the analysis. In addition, new obligations for Resource Support Services and Forced Outage Reserve requirements resulting from Regional Dialogue contracts were not modeled. Nor were transmission impacts modeled. Incorporating transmission constraints, increased load growth and

increased requirements in these studies can be expected to exacerbate the complications created by rising reserve requirements for wind integration.

Risks:

This analysis is a single issue study that isolates the incremental impact of holding additional reserve requirements on the Federal system. This study does not capture any risks associated with deploying Federal reserves to balance a variable wind profile such as: managing forebay bounces, navigation issues, transmission redispatch and reliability if GCL is disproportionately responding to large swings, and unit operational cycling costs.

It is important to note that these reserve requirements are functions of the assumptions in the September 10, 2008, WIT report. The reserve requirements assume a particular level of forecasting accuracy. Sensitivity analyses show the reserve requirement to be very sensitive to this assumption. To the extent forecasts are demonstrated to be more accurate, or other provisions to limit BPA's reserve exposure are put in place (e.g. through Large Generator Interconnection Agreements and a new Dispatch Standing Order), these reserve requirements can be reduced for a given wind fleet size. However, the reserve carrying capability of the current FCRPS does not change from the values above.

The fish protection and other operating constraints on the Lower Columbia limit the ability of those plants to hold regulating reserves. Any future fisheries requirements that further limit the flexibility of these projects (e.g., increased spill or requirements that limit reservoir content), would decrease the amount of regulating reserves and load following response available from those projects. Allocating the response to fewer projects could risk the ability to manage transmission overloads (redispatch) and the ability to respond to wind imbalances and inflow uncertainties. Also, a reduction in generation available for load service would transfer that load service obligation to other projects, including projects that could otherwise have flexibility to follow wind movement.

Approach D = Power and Conservation Council's Resource Adequacy Standards for the Northwest

In April 2008, the Northwest Power and Conservation Council (Council) adopted resource adequacy standards that were developed by the Pacific Northwest Resource Adequacy Forum. These standards for both energy and capacity provide a minimum threshold that serves as an early warning should resource development fall dangerously short. These are minimum thresholds and should not be mistaken for resource planning targets.

Utility-by-utility deterministic translation of these standards has yet to occur, but high level guidance to align utility resource planning efforts with the regional standard has been provided for the energy standard. This high level guidance suggests that utilities should include the amount of market and non-firm hydro resources assumed to be available to them in their energy planning efforts based on their pro rata share of these resources, i.e. based on their percentage shares of regional load and regional hydro resources, respectively. For the Federal system, the share of these regional resources is 2,036 average megawatts.

The energy metric is defined to be the annual load/resource balance with a threshold of zero using critical water for firm hydro generation. For 2013, the Preliminary Needs Assessment forecasts an annual average deficit of 750 average megawatts. However, when the Federal system pro rata shares of market and non-firm resources are included, the Federal system is 1,286 average megawatts energy surplus. Therefore, the Federal system meets the energy threshold of the regional adequacy standards.

Note, the standard is meant to be merely a minimum threshold for reliability. It is less stringent than what the Council expects utilities to use for prudent resource planning (such as Integrated Resource Plans or BPA's Resource Program).[19]

We have not yet completed an assessment of BPA's capacity under the Council's resource adequacy standard. The Council's schedule calls for utilities to perform this analysis this spring or summer.

[19] Per conversation with NWPCC staff.

Appendix: Technical Details for Approach C.

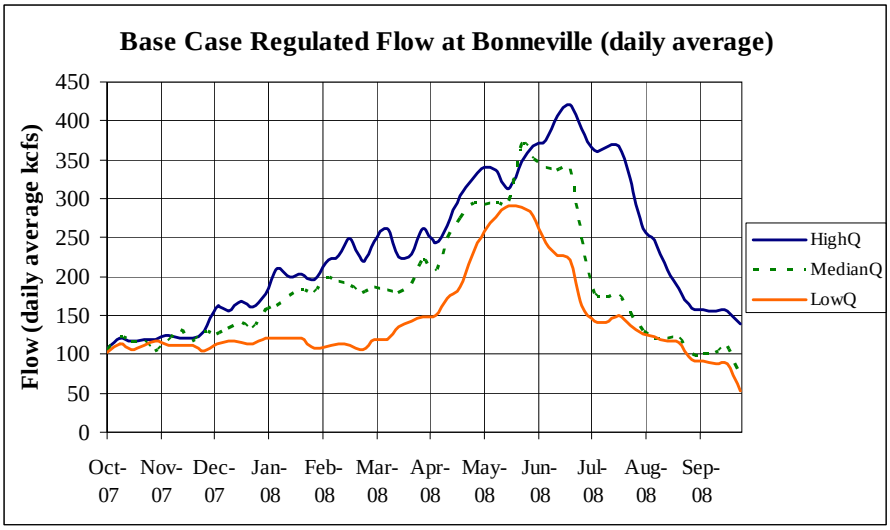
System Components Modeled: Only the "Big 10" federal projects were modeled to manage the run times and study scope. The non-federal Mid-Columbia projects were hydraulically modeled to pass inflow. The hydro regulation from projects upstream of GCL included the Willamette dams, Libby, Hungry Horse, Albeni Falls, and Dworshak generation.

Grand Coulee and Lower Granite dam inflows: The hydrologic years were selected from a set of ESP water years. The objective was to find a fair representation of the 90 percent, 50 percent, and 10 percent exceedence levels. The selection methodology broke out the year into four periods; Oct-Sep, Dec-Mar, April-Jul and Aug-Sep. The first period represented the transition into the new water year, the second period represented the winter, the third represented the majority of the freshet season, and the last represented the transition to lower summer flows. For each of these periods, the average flows were considered for The Dalles, Grand Coulee, and Lower Granite. In looking at the different cases (90 percent, 50 percent, 10 percent), it was difficult to find a consistent year across all three forecast points and in all periods. Consequently, the selection process placed more emphasis on the total volumes during the winter and freshet seasons, and less consideration on the fall and late summer. Based on this, the following years were selected:

Water volume at The Dalles for hydrology selection

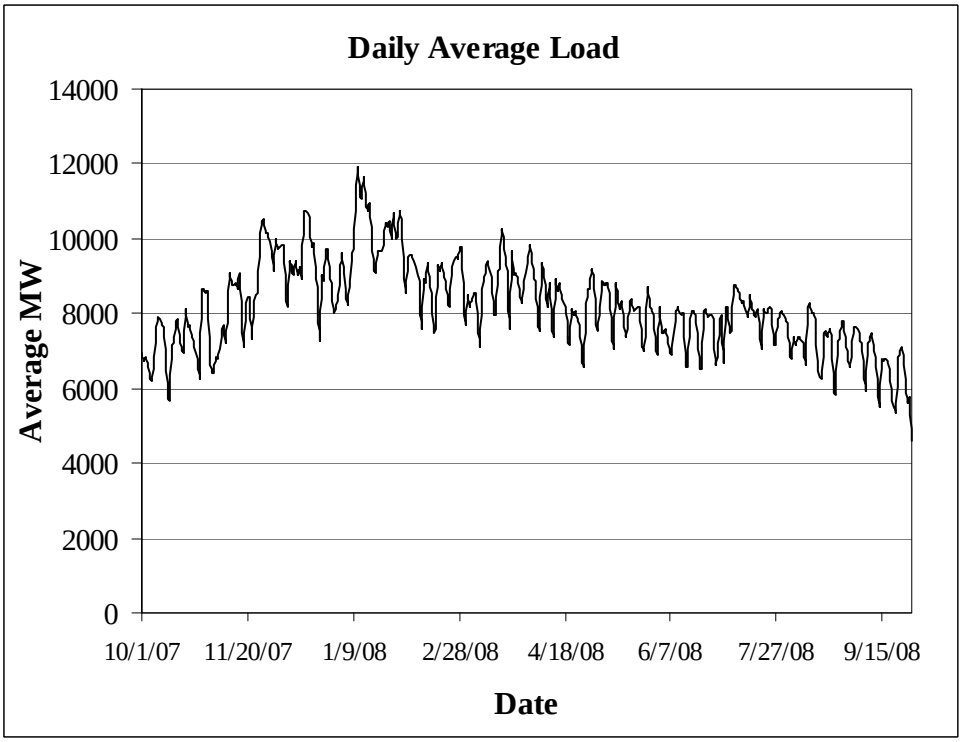
	Year	**Case**	**Jan-July Vol. at TDA**	**Oct-Sep Volume**
90%	1992	Low	77 maf	99 maf
50%	1958	Median	104 maf	129 maf
10%	1982	High	130 maf	167 maf

The average regulated discharge at Bonneville for the three water years selected is shown below.



Average Regulated Flow at Bonneville

Loads: The load profile used in the study was defined on an hourly basis and remained the same through each hydrologic sequence and reserve requirement scenario. The load was calculated by taking the generation from FY 2007 (adjusted for wind) and subtracting out the trading floor deals.



Average daily load profile

External Energy Sources: External energy sources included hydro independent, Willamette and non-hydro sources. These energy contributors were loaded as external energy sources on the BPA Bus. As a note, the external energy values were taken from the 8/21 Data Center. The Willamette generation and the generation values for LIB, HGH, ALF, and DWR are from the HYDSIM FY08 Study #2.

Markets: In all of the studies the wholesale purchase market has a limit of 4,000 MWh and the sale market is effectively unlimited. The prices came from the Aurora pricing model based off of the generation from the HYDSIM FY08 Study #2.

Availabilities: Operational conditions were based on plant availabilities defined in HYDSIM FY08 Study #2 adjusted for how reserves are treated in HYDSIM. These plant availabilities were then translated into unit outages. Because of the expected overhaul of the 3rd powerhouse units at Grand Coulee, one 805 MW unit was out of service the entire study period.

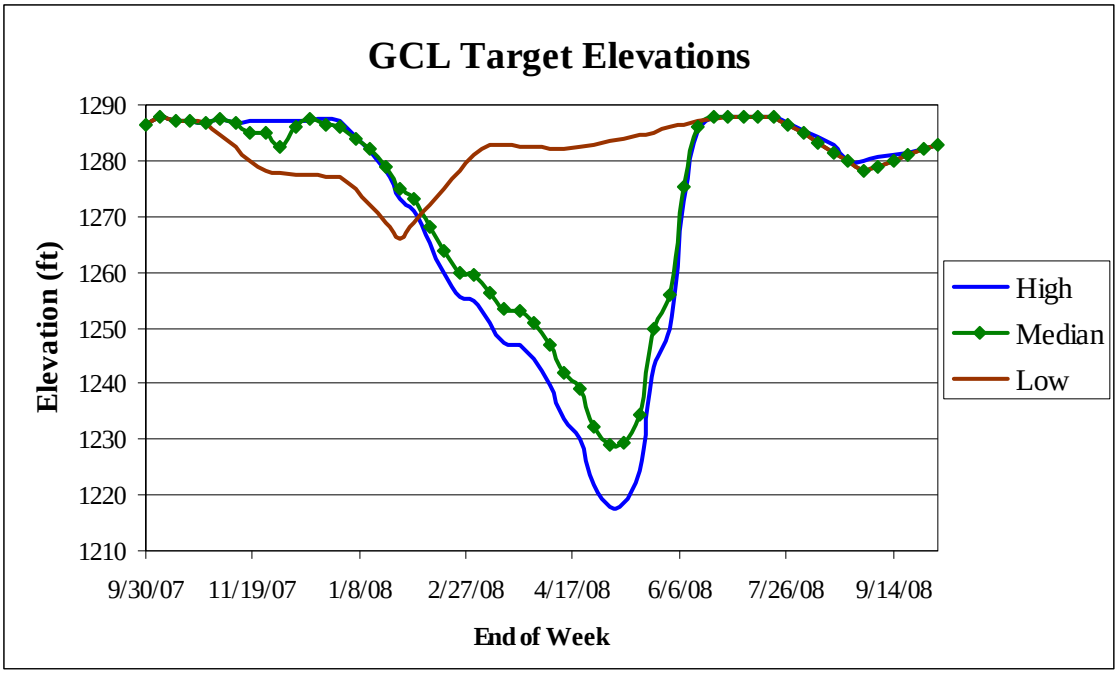
Hourly Blocking: To get results in a timely fashion, a seven-period blocking rather than hourly time steps were used for these studies. Even blocked, the year long studies took approximately 24 hours to complete. Over a long holiday weekend, test runs of a 2 hour grouping took approximately 3 days to complete. The hourly time step took a few weeks of computation time.

Regulating Reserves: Grand Coulee, Chief Joseph, McNary, John Day, and The Dalles were eligible for regulation, spin and non-spin reserve types. All other projects were eligible for spin and non spin only. The reserve levels used in this study are based on the *Regulation, Load Following and Generation/Load Imbalance* report prepared by the BPA Wind Integration Team (WIT) and presented on September 10, 2008, an average summary of the requirement is listed below.

Average Regulation Reserve Requirement

FY **Wind**	**Base** **0 MW**	**2008** **1425 MW**	**2009** **2105 MW**	**2010** **3155 MW**	**2011** **4330 MW**	**2012** **5570 MW**	**2013** **6670 MW**
Up Reg	679	757	894	1179	1414	1693	1983
Down Reg	837	884	1048	1453	1773	2174	2542

Run Scenarios: Run scenarios included a base case and several future reserve cases. The evaluation and calibration of operations under existing conditions was performed over a 1 year period for the three flow cases. Operation constraints were adjusted during the spring runoff season to accommodate the different flow volumes and form the base case condition. Grand Coulee water level constraints were supplied to guide operations for each of the hydrologic years. The results were compared as incremental changes from the base to represent the additional operating costs associated with the additional wind integration reserve requirements



Grand Coulee target water levels

Glossary

Above-High-Water-Mark Loads which a customer has above that customer's highest load-carrying capability utilizing BPA resources and the customer's own resources, as determined in the rate-period high-water-mark process under the Regional Dialog.

Agency Load Forecasting Tool(ALF) BPA's load forecasting tool that uses historical load, load trends, and temperature information to forecast loads for the future.

Ancillary Services Technical within-hour power and transmission services necessary for reliable power delivery other than simple megawatt-hours. Includes spinning and non-spinning generation reserves, VAR support, within-hour load following and regulation, generation imbalance and others. Some ancillary services are charged in power rates, others in transmission rates, and others are provided without specific charge. The Preliminary Needs Assessment refers specifically to ancillary services purchased by BPA Transmission from BPA Power (FCRPS resources) to support transmission reliability.

Auto Vista Auto Vista is an historical simulator which simulates system response for a range of hydrologic inputs for defined physical and operational constraints, simulating the operation of the system over a user-defined historical period, using operational procedures analogous to those used in actual practice. It is a component of Columbia Vista.

Balancing Authority (New term for Control Area) The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Reserves A portion of the operating system that is held ready to maintain load resource balance at all times. This includes load following, regulating reserves, generation imbalance (scheduling error), and the variability of intermittent resources (up reg or INC and down reg or DEC)

BiOp Biological Opinion, A determination by a responsible Federal agency as to whether the operating plan of a subject Federal agency is adequate to protect affected species listed under the Endangered Species Act. For the Preliminary Needs Assessment, the relevant BiOp is the 2008 BiOp on FCRPS operations for Columbia Basin salmon and steelhead.

Capacity The greatest amount of power a generator or system of generators can supply at its peak output for a given period. The Preliminary Needs Assessment specifically analyses FCRPS capacity that can be sustained over 18-hour and 120-hour periods under varying water conditions. Measured in megawatts.

Capacity factor The portion of a generator's nameplate rated output that can be: 1) relied upon to be available at need, or 2) average output. (These two definitions can be

quite different.) For wind generation, the term "capacity factor" generally refers to the generator's average output.

CGS Columbia Generating Station, a nuclear plant owned by Energy Northwest, for which BPA markets all power.

ColumbiaGrid Regional transmission entity being developed by BPA, Puget Sound Energy, Chelan and Grant Public Utility Districts, and Seattle City Light.

Columbia Vista A decision support system computer model developed by Acres International of Ontario, Canada on the Vista platform as adapted to the Columbia River FCRPS.

Critical water The historic sequence of streamflows least able to refill FCRPS reservoirs. Specifically: October 1936 to September1937 in this study.

DEC [decremental] Downward-regulating, load-following reserves; a backing-off of a system's generation as wind or other generation picks up or as area load drops off.

Direct-Service Industries (DSIs): Industrial customers, primarily aluminum smelters, that buy power directly from BPA at relatively high voltages.

Downward regulation (*down reg*) The backing-off, or regulation, of a power system's base generation in response to a rising contribution of a non-dispatchable resource such as wind contributes more energy, or in response to a decreasing contribution from load.

Dynamic scheduling Control of and responsibility for providing ancillary services to support a resource that is physically located in a different balancing authority, through remote electrical controls. BPA is working on developing greater ability to allow other utilities to dynamically schedule wind resources located in BPA's balancing authority.

Energy Where used specifically, an amount of electricity consumed over time, which may include periods of higher and lower consumption within that time frame. Measured in megawatt-hours or average MW.

Ensemble Streamflow Prediction (ESP) A probabilistic streamflow prediction model, developed by the National Weather Service, that uses conceptual hydrologic models and historical data to generate a distribution set, or ensemble, of possible streamflow scenarios with uncertainty, conditioned on the initial states of a given basin.

FCRPS Federal system Federal Columbia River Power System: The transmission system constructed and operated by BPA and the hydro-electric dams constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Northwest. Each entity is separately managed and financed, but the facilities are operated as an integrated power system. Approaches A and B in the Preliminary Needs Assessment include the Columbia Generating Station and other nonfederal resources

marketed by BPA. Approach C, the Wind Reserve Impacts Study, includes only federal hydropower.

Forced Outage Reserves As used here, a power product BPA is offering its customers under Regional Dialogue Contracts.

GCL Grand Coulee hydroelectric facility

HLH Heavy-Load Hours. Typically (but not universally) the 16 daily hours between 6 a.m. and 10 p.m., Monday through Saturday not including holidays; can be negotiated on a contract-by-contract basis otherwise.

HOSS Hourly Operating and Scheduling Simulator: A computer model that simulates the hourly dispatch and short-term marketing of Northwest thermal and hydropower resources for a study period of up to four weeks. It is used to examine system capacity, marketing, and various environmental concerns that require hourly detail.

Hydrologic Simulator Model (HYDSIM or HydSim) A monthly-step computer river simulation model that routes water from the headwaters of the Columbia basin as it actually occurred through the system of dams, storing in and drafting from reservoirs to meet non-power and power requirements established by the modeler.

High Water Mark The amount of power a BPA utility customer can purchase from BPA at Tier 1 rates, reflecting costs of the existing federal hydro system, as established in the Regional Dialogue Policy.

INC [incremental] Upward regulating; a picking-up of a system's baseload generation as wind or other renewable generation backs off, or as load increases.

Intermittent generation See non-dispatchable or variable generation. An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

LLH Light-Load Hours. Remaining hours of the week that are not defined as heavy-load hours.

Load The total amount of electricity used at any given time or over any given period that a utility is obligated to serve or balancing authority area must balance with generation.

Loads and Resources Information System (LaRIS) A BPA Power Services data repository software system for information on loads, resources, and contracts.

Marketing and Sales Enterprise Process Improvement Project (M&S EPIP) Review, reassessment and reorganization project proposed by consultant KEMA to consolidate and create efficiencies in the areas of Transmission and Power sales and marketing activities consistent with federal regulation, to include billing, metering, budgeting,

human capital management, evaluation and forecasting of loads and resources, communications reinforcements, and structural improvements.

Non-dispatchable resources An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints. Resources such as wind power that cannot increase or produce generation at the command of their operators, but are only available at Nature's discretion. See variable or intermittent generation.

Non-power operating requirements: Constraints on Federal hydro production not related to power production, such as minimum pool elevations to allow barge navigation and irrigation water withdrawals, flood-control requirements, and fish protection requirements.

NWPCC Northwest Power and Conservation Council: An eight-member council, established by the Pacific Northwest Electric Power Planning and Conservation Act. Comprised of two voting members from the four Northwestern states: Washington, Oregon, Idaho, and Montana. Helps guide BPA and the region with planning for conservation and generation resources and for protection, mitigation, and enhancement of fish and wildlife in the Columbia River Basin.

Northwest Wind Integration Forum Advisory committee to NWPCC, created in 2007 and scheduled to disband in 2009, whose 26-member Steering Committee has reviewed through its Technical Workgroup operational and infrastructure issues associated with large-scale wind energy development in the Pacific Northwest and to define actions that Northwest parties could undertake to help the region meet its wind energy objectives in a reliable, least-cost fashion.

Obligations, net obligations The sum of BPA's contracted power supply or transmission responsibilities for a given time period. Net obligations are net of any countervailing sources or mandates.

120-hour sustained peaking The term 'super-peak' analysis is used in the inventory study for the same metric as the '120-hour sustained peaking capacity' term in the White Book. It is a measure of the system's ability to meet the peaks day-after-day throughout the month (6 hours/day, 5 days/week, 4 weeks/month 6*5*4=120).

Peak load: The highest amount of electricity used in a specific area, either for a moment, an hour, a set of hours, or another specified period. To maintain reliability, peak loads must always be less than generation capacity available to the specified area. The Preliminary Needs Assessment analyzes peak loads in **18-hour** and **120-hour "Superpeak"** increments.

P5 The 5% exceedence probability level, having the chance of occurring of 1 out of 20 times.

P10 The 10% exceedence probability level, having the chance of occurring of 1 out of 10 times.

Redispatch Redirection of a power flow from one transmission path to another by the Dispatcher, normally to maintain system reliability and avoid transmission congestion.

Reserves, Operating reserves In a power system, the capability in excess of that required to carry the normal total load. Electric power needed to serve customers in the event of generation or transmission system outages, adverse streamflows, delays in completion of new resources, or other factors which may restrict generating capability or increase loads. Normally provided from additional resources acquired for that purpose, or from contractual rights to interrupt, curtail, or otherwise withdraw portions of the electric power supplied to customers.

Reserve requirements Amounts and types of reserves a Balancing Authority must maintain in available status to comply with North American Electric Reliability Corporation, Western Electricity Coordinating Council, or other regulatory requirements. Includes contingency reserves (half **spinning, half nonspinning), regulating reserves, load following, generation imbalance and contingency reserves**.

Resource Any source of power supply that can be contractually assured.

Resource Adequacy Standard (energy and/or capacity) A standard set by a regulatory or similar body determining how much excess energy supply a utility must have available to assure it can meet expected energy or capacity loads beyond those presently realized. In this study, we are referring to the Regional Resource Adequacy Standard adopted by the NWPCC (the Council).

Resource Support Services (RSS) A new class of power services BPA is making available to its customers for purchase under its Regional Dialogue Contracts. For example, Resource Support Services would allow a customer to purchase services to shape variable output of a wind project owned by a customer utility into flat blocks of power. The Preliminary Needs Assessment does not estimate the potential requirements associated with this new service.

Secondary Power over and above BPA's firm power obligations to its customers that may be sold in the competitive wholesale power market. BPA's **net secondary** sales are net of its power purchases in that market to meet its firm obligations.

Shaping Taking energy (or streamflows) from a generation source as it is produced, and providing, in return, energy (or water) in the amount(s) over time as requested by the customer or as required. BPA shapes streamflows to meet spill and flow requirements for fish. BPA offers to shape energy from a customer's power source into flat blocks of power for a customers' baseload in its Resource Support Service.

Spill, spill requirements Spill is water sent through the spillways of a dam rather than through generating turbines, either for fish protection, because there is no market for the

power that would be produced, or because streamflows exceed turbine capacity. Spill requirements are amounts and timing of spill to protect fish.

Spinning reserves Generators that are turned on and synchronized with the grid, literally spinning but not connected to load or that are not operating at full capacity – held on stand-by to increase generation at a moment's notice.

Stochastic Involving a random variable, or a study based on probability of occurrence.

Tier-1 Rate component in a BPA rate case that comprises the collection of resources and contract purchases that comprise the Tier 1 system resources (Federal System hydro generation resources plus certain designated non-Federally-owned resources and certain designated BPA contract purchases), and the collection of contract loads and obligations that comprise the Designated BPA System Obligations. Tier-1 and Tier-2 are both defined in the Regional Dialog and Tiered Rates Methodology.

Tier-2 Rate component in a BPA rate case that comprises any Priority Firm Power (PF) rate that reflects Tier 2 costs and applies to power purchased under a contract to meet a customer's above-rate-period-high-water-mark Load.

2-Hour persistence scheduling accuracy (for wind) Under a 2-hour persistence scheduling accuracy, the forecast of wind generation for an hour is at least as good as assuming that the level of generation 2 hours before the hour will persist.

Upward regulation (*Up reg*) Spinning reserves ready to increase generation to compensate for a declining contribution of a non-dispatchable resource such as wind, or an increase in load. This is in addition to the spinning reserves that stand ready to respond to contingency outages.

Variable generation An electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints. Hydropower is variable beyond the storage capabilities of reservoirs. Wind and solar output vary with wind and sun, respectively. Tidal and wave energy will no doubt prove variable, within patterns of those resources. See non-dispatchable, intermittent.

Wind Integration Team (WIT) BPA wind study group formed in the WI-09 Rate Case Settlement to study and report on the operational and infrastructure issues associated with integrating large-scale wind resources into the electrical grid. (The Northwest Wind Integration Forum is a public study group providing advice to the WIT and to other utilities as they implement the Northwest Wind Integration Action Plan of 2007.)

Within-hour sales or scheduling Power generation is typically scheduled over transmission paths by the hour. Some utilities and balancing authorities, such as the California Independent System Operator, have developed the ability to schedule some generation changes within hours. BPA is working on developing this capability in concert with other western utilities, particularly to support variable wind generation.

BONNEVILLE POWER ADMINISTRATION

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